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

OR

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

For the transition period from to

Commission file number 001-35410

MATADOR RESOURCES COMPANY
(Exact name of registrant as specified in its charter)

Texas **(State or other jurisdiction of incorporation or organization)**	**27-4662601** **(I.R.S. Employer Identification No.)**
5400 LBJ Freeway, Suite 1500 **Dallas, Texas 75240** **(Address of principal executive offices)**	**75240** **(Zip Code)**

(972) 371-5200
(Registrant's telephone number, including area code)

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 (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☒ Yes ☐ No

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

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

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

As of August 14, 2012, there were 55,499,209 shares of the registrant's common stock, par value $0.01 per share, outstanding.

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FORM 10-Q
FOR THE QUARTER ENDED JUNE 30, 2012

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Part I – Financial Information

Item 1. Financial Statements

Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED BALANCE SHEETS — UNAUDITED
(In thousands, except par value and share data)

	June 30, 2012	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 9,432	$ 10,284
Certificates of deposit	266	1,335
Accounts receivable		
Oil and natural gas revenues	11,898	9,237
Joint interest billings	2,378	2,488
Other	1,656	1,447
Derivative instruments	16,033	8,989
Lease and well equipment inventory	1,381	1,343
Prepaid expenses	1,538	1,153
Total current assets	44,582	36,276
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	564,026	423,945
Unproved and unevaluated	166,230	162,598
Other property and equipment	22,102	18,764
Less accumulated depletion, depreciation and amortization	(269,766)	(205,442)
Net property and equipment	482,592	399,865
Other assets		
Derivative instruments	5,093	847
Deferred income taxes	4,594	1,594
Other assets	828	887
Total other assets	10,515	3,328
Total assets	$ 537,689	$ 439,469
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 16,874	$ 18,841
Accrued liabilities	36,259	25,439
Royalties payable	5,497	1,855
Borrowings under Credit Agreement	—	25,000
Derivative instruments	—	171
Deferred income taxes	5,376	3,024
Dividends payable - Class B	—	69
Other current liabilities	56	177
Total current liabilities	64,062	74,576
Long-term liabilities		
Borrowings under Credit Agreement	60,000	88,000
Asset retirement obligations	4,363	3,935
Derivative instruments	—	383
Other long-term liabilities	1,487	1,060
Total long-term liabilities	65,850	93,378
Commitments and contingencies (Note 10)		
Shareholders' equity		
Common stock - Class A, $0.01 par value, 80,000,000 shares authorized; 56,691,718 and 42,916,668 shares issued; 55,502,543 and 41,737,493 shares outstanding, respectively	566	429
Common stock - Class B, $0.01 par value, zero and 2,000,000 shares authorized; zero and 1,030,700 shares issued and outstanding, respectively	—	10
Additional paid-in capital	402,622	263,562
Retained earnings	15,376	18,279
Treasury stock, at cost, 1,189,175 and 1,179,175 shares, respectively	(10,787)	(10,765)
Total shareholders' equity	407,777	271,515
Total liabilities and shareholders' equity	$ 537,689	$ 439,469

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

Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS — UNAUDITED
(In thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Revenues				
Oil and natural gas revenues	$ 36,078	$20,864	$65,242	$ 34,562
Realized gain on derivatives	4,713	952	7,776	2,802
Unrealized gain (loss) on derivatives	15,114	332	11,844	(1,336)
Total revenues	55,905	22,148	84,862	36,028
Expenses				
Production taxes and marketing	2,619	1,654	4,783	2,954
Lease operating	6,375	1,969	11,020	3,574
Depletion, depreciation and amortization	19,913	8,179	31,119	15,290
Accretion of asset retirement obligations	58	57	111	96
Full-cost ceiling impairment	33,205	—	33,205	35,673
General and administrative	4,093	3,094	7,882	5,712
Total expenses	66,263	14,953	88,120	63,299
Operating (loss) income	(10,358)	7,195	(3,258)	(27,271)
Other income (expense)				
Net loss on asset sales and inventory impairment	(60)	—	(60)	—
Interest expense	(1)	(183)	(309)	(290)
Interest and other income	30	94	103	166
Total other expense	(31)	(89)	(266)	(124)
(Loss) income before income taxes	(10,389)	7,106	(3,524)	(27,395)
Income tax provision (benefit)				
Current	—	(46)	—	(46)
Deferred	(3,713)	—	(649)	(6,906)
Total income tax benefit	(3,713)	(46)	(649)	(6,952)
Net (loss) income	$ (6,676)	$ 7,152	$ (2,875)	$(20,443)
Earnings (loss) per common share				
Basic				
Class A	$ (0.12)	$ 0.17	$ (0.06)	$ (0.48)
Class B	$ —	$ 0.23	$ 0.07	$ (0.35)
Diluted				
Class A	$ (0.12)	$ 0.17	$ (0.06)	$ (0.48)
Class B	$ —	$ 0.23	$ 0.07	$ (0.35)
Weighted average common shares outstanding				
Basic				
Class A	55,271	41,667	52,434	41,646
Class B	—	1,031	210	1,031
Total	55,271	42,698	52,644	42,677
Diluted				
Class A	55,271	41,782	52,434	41,646
Class B	—	1,031	210	1,031
Total	55,271	42,813	52,644	42,677

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

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Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY – UNAUDITED
(In thousands)

For the six months ended June 30, 2012

	Common stock				Additional paid-in capital	Retained earnings	Treasury stock		Total
	Class A		Class B						
	Shares	Amount	Shares	Amount			Shares	Amount	
Balance at January 1, 2012	42,917	$ 429	1,031	$ 10	$263,562	$18,279	(1,179)	$(10,765)	$271,515
Issuance of Class A common stock	12,209	122	—	—	146,388	—	—	—	146,510
Cost to issue equity	—	—	—	—	(11,268)	—	—	—	(11,268)
Conversion of Class B common stock to Class A common stock	1,031	10	(1,031)	(10)	—	—	—	—	—
Issuance of Class A common stock to Board advisors	6	—	—	—	61	—	—	—	61
Stock options expense	—	—	—	—	47	—	—	—	47
Stock options exercised	295	3	—	—	3,541	—	—	—	3,544
Liability based stock option awards forfeited or expired	—	—	—	—	86	—	—	—	86
Restricted stock issued	234	2	—	—	(2)	—	—	—	—
Restricted stock forfeited	—	—	—	—	—	—	(10)	(22)	(22)
Restricted stock and restricted stock units expense	—	—	—	—	183	—	—	—	183
Swing sale profit contribution	—	—	—	—	24	—	—	—	24
Class B dividends declared	—	—	—	—	—	(28)	—	—	(28)
Current period net loss	—	—	—	—	—	(2,875)	—	—	(2,875)
Balance at June 30, 2012	56,692	$ 566	—	$ —	$402,622	$15,376	(1,189)	$(10,787)	$407,777

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

Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS — UNAUDITED
(In thousands)

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Operating activities		
Net loss	$ (2,875)	$ (20,443)
Adjustments to reconcile net loss to net cash provided by operating activities		
Unrealized (gain) loss on derivatives	(11,844)	1,336
Depletion, depreciation and amortization	31,119	15,290
Accretion of asset retirement obligations	111	96
Full-cost ceiling impairment	33,205	35,673
Stock option and grant expense	(333)	159
Restricted stock and restricted stock units expense	161	22
Deferred income tax benefit	(649)	(6,906)
Loss on asset sales and inventory impairment	60	—
Changes in operating assets and liabilities		
Accounts receivable	(2,761)	(3,526)
Lease and well equipment inventory	(98)	(1)
Prepaid expenses	(385)	366
Other assets	59	—
Accounts payable, accrued liabilities and other liabilities	1,687	(3,330)
Royalties payable	3,642	1,643
Advances from joint interest owners	—	(723)
Other long-term liabilities	427	(125)
Net cash provided by operating activities	51,526	19,531
Investing activities		
Oil and natural gas properties capital expenditures	(134,425)	(89,632)
Expenditures for other property and equipment	(3,521)	(1,722)
Purchases of certificates of deposit	(266)	(2,663)
Maturities of certificates of deposit	1,335	2,928
Net cash used in investing activities	(136,877)	(91,089)
Financing activities		
Repayments of borrowings under Credit Agreement	(123,000)	—
Borrowings under Credit Agreement	70,000	60,000
Proceeds from issuance of common stock	146,510	592
Swing sale profit contribution	24	—
Cost to issue equity	(11,599)	(758)
Proceeds from stock options exercised	2,660	725
Payment of dividends - Class B	(96)	(137)
Net cash provided by financing activities	84,499	60,422
Decrease in cash and cash equivalents	(852)	(11,136)
Cash and cash equivalents at beginning of period	10,284	21,059
Cash and cash equivalents at end of period	$ 9,432	$ 9,923

Supplemental disclosures of cash flow information (Note 11)

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

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS –

UNAUDITED

NOTE 1 - NATURE OF OPERATIONS

Matador Resources Company ("Matador" or the "Company") is an independent energy company engaged in the exploration, development, acquisition and production of oil and natural gas resources in the United States, with a particular emphasis on oil and natural gas shale plays and other unconventional resource plays. Matador's current operations are located primarily in the Eagle Ford shale play in South Texas and the Haynesville shale play in Northwest Louisiana and East Texas. In addition to these primary operating areas, Matador has acreage positions in Southeast New Mexico and West Texas and in Southwest Wyoming and adjacent areas in Utah and Idaho where the Company continues to identify new oil and natural gas prospects.

On November 22, 2010, the company formerly known as Matador Resources Company, a Texas corporation founded on July 3, 2003, formed a wholly-owned subsidiary, Matador Holdco, Inc. Pursuant to the terms of a corporate reorganization that was completed on August 9, 2011, the former Matador Resources Company became a wholly owned subsidiary of Matador Holdco, Inc. and changed its corporate name to MRC Energy Company, and Matador Holdco, Inc. changed its corporate name to Matador Resources Company.

MRC Energy Company holds the primary assets of the Company and has four wholly owned subsidiaries: Matador Production Company, MRC Permian Company, MRC Rockies Company and Longwood Gathering and Disposal Systems GP, Inc. Matador Production Company serves as the oil and natural gas operating entity. MRC Permian Company conducts oil and natural gas exploration and development activities in Southeast New Mexico. MRC Rockies Company conducts oil and natural gas exploration and development activities in the Rocky Mountains and specifically in the states of Wyoming, Utah and Idaho. Longwood Gathering and Disposal Systems GP, Inc. serves as the general partner of Longwood Gathering and Disposal Systems, LP which owns a majority of the pipeline systems and salt water disposal wells used in the Company's operations and also transports limited quantities of third-party natural gas.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Interim Financial Statements, Basis of Presentation, Consolidation and Significant Estimates

The unaudited condensed consolidated financial statements of Matador and its subsidiaries have been prepared in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") but do not include all of the information and footnotes required by generally accepted accounting principles in the United States of America ("U.S. GAAP") for complete financial statements and should be read in conjunction with the Company's 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 filed with the SEC. All intercompany accounts and transactions have been eliminated in consolidation. In management's opinion, these interim unaudited condensed consolidated financial statements include all adjustments of a normal recurring nature necessary for a fair presentation of the Company's consolidated financial position as of June 30, 2012, consolidated results of operations for the three and six months ended June 30, 2012 and 2011, consolidated changes in shareholders' equity for the six months ended June 30, 2012 and consolidated cash flows for the six months ended June 30, 2012 and 2011. Certain reclassifications have been made to prior period items to conform to the current period presentation. These reclassifications had no effect on previously reported results of operations, cash flows or retained earnings. Amounts as of December 31, 2011 are derived from the audited consolidated financial statements as filed with the SEC in our Annual Report on Form 10-K for the year ended December 31, 2011.

Accounting measurements at interim dates inherently involve greater reliance on estimates than at year end and the results for the interim periods shown in this report are not necessarily indicative of results to be expected for the full year due in part to volatility in oil and natural gas prices, global economic and financial market conditions, interest rates, access to sources of liquidity, estimates of reserves, drilling risks, geological risks, transportation restrictions, oil and natural gas supply and demand, market competition and interruptions of production.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS –

UNAUDITED — CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates and assumptions may also affect disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. The Company's consolidated financial statements are based on a number of significant estimates, including accruals for oil and natural gas revenues, accrued assets and liabilities primarily related to oil and natural gas operations, stock-based compensation, valuation of derivative instruments and oil and natural gas reserves. The estimates of oil and natural gas reserves quantities and future net cash flows are the basis for the calculations of depletion and impairment of oil and natural gas properties, as well as estimates of asset retirement obligations and certain tax accruals. While the Company believes its estimates are reasonable, changes in facts and assumptions or the discovery of new information may result in revised estimates. Actual results could differ from these estimates.

Property and Equipment

The Company uses the full-cost method of accounting for its investments in oil and natural gas properties. Under this method of accounting, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing the Company's activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects and general and administrative expenses directly related to exploration and development activities, but do not include any costs related to production, selling or general corporate administrative activities. The Company capitalized approximately $1.1 million and $0.9 million of its general and administrative costs for the six months ended June 30, 2012 and 2011, respectively. The Company capitalized approximately $0.6 million and $0.3 million of its interest expenses for the six months ended June 30, 2012 and 2011, respectively.

The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized costs less related deferred income taxes or the cost center ceiling, with any excess above the cost center ceiling charged to operations as a full-cost ceiling impairment. The need for a full-cost ceiling impairment is assessed on a quarterly basis. The cost center ceiling is defined as the sum of (a) the present value discounted at 10 percent of future net revenues of proved oil and natural gas reserves, plus (b) unproved and unevaluated property costs not being amortized, plus (c) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less (d) income tax effects related to the properties involved. Future net revenues from proved non-producing and proved undeveloped reserves are reduced by the estimated costs for developing these reserves. The fair value of the Company's derivative instruments is not included in the ceiling test computation as the Company does not designate these instruments as hedge instruments for accounting purposes.

The estimated present value of after-tax future net cash flows from proved oil and natural gas reserves is highly dependent on the commodity prices used in these estimates. These estimates are determined in accordance with guidelines established by the SEC for estimating and reporting oil and natural gas reserves. Under these guidelines, oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost escalations in future periods except by contractual arrangements.

The commodity prices used to estimate oil and natural gas reserves are based on unweighted, arithmetic averages of first-day-of-the-month oil and natural gas prices for the previous 12-month period. For the period July 2011 through June 2012, these average oil and natural gas prices were $92.17 per Bbl and $3.146 per MMBtu (million British thermal units), respectively. For the period July 2010 through June 2011, these average oil and natural gas prices were $86.60 per Bbl and $4.209 per MMBtu, respectively. In estimating the present value of after-tax future net cash flows from proved oil and natural gas reserves, the average oil prices were adjusted by property for quality, transportation and marketing fees and regional price differentials, and the average natural gas prices were adjusted by property for energy content, transportation and marketing fees and regional price differentials. At June 30, 2012 and 2011, the Company's oil and natural gas reserves estimates were prepared by the Company's engineering staff in accordance with guidelines established by the SEC and then audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS –

UNAUDITED — CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

Using the average commodity prices, as adjusted, to determine the Company's estimated proved oil and natural gas reserves at June 30, 2012, the Company's net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $21.3 million. The Company recorded an impairment charge of $33.2 million to its net capitalized costs and a deferred income tax credit of $11.9 million related to the full-cost ceiling limitation at June 30, 2012. Corresponding charges were also recorded in the Company's unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2012. At March 31, 2011, the Company's net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $23.0 million. The Company recorded an impairment charge of $35.7 million to its net capitalized costs and a deferred income tax credit of $12.7 million related to the full-cost ceiling limitation at March 31, 2011. These charges are reflected in the Company's unaudited condensed consolidated statement of operations for the six months ended June 30, 2011. Changes in oil and natural gas production rates, reserves estimates, future development costs and other factors will determine the Company's actual ceiling test computation and impairment analyses in future periods.

As a non-cash item, the full-cost ceiling impairment impacts the accumulated depletion and the net carrying value of the Company's assets on its balance sheet, as well as the corresponding shareholders' equity, but it has no impact on the Company's net cash flows as reported.

Capitalized costs of oil and natural gas properties are amortized using the unit-of-production method based upon production and estimates of proved reserves quantities. Unproved and unevaluated property costs are excluded from the amortization base used to determine depletion. Unproved and unevaluated properties are assessed for possible impairment on a periodic basis based upon changes in operating or economic conditions. This assessment includes consideration of the following factors, among others: the assignment of proved reserves, geological and geophysical evaluations, intent to drill, remaining lease term and drilling activity and results. Upon impairment, the costs of the unproved and unevaluated properties are immediately included in the amortization base. Dry holes are included in the amortization base immediately upon determination that the well is not productive.

Earnings Per Common Share

The Company reports basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities, unless their impact is anti-dilutive.

Prior to the consummation of the Company's Initial Public Offering (see Note 7) in February 2012, the Company had issued two classes of common stock, Class A and Class B. The holders of the Class B shares were entitled to be paid cumulative dividends at a per share rate of $0.26-2/3 annually out of funds legally available for the payment of dividends. These dividends were accrued and paid quarterly. Dividends declared during the three months ended June 30, 2012 and 2011 totaled zero and $68,713, respectively. Dividends declared during the six months ended June 30, 2012 and 2011 totaled $27,643 and $137,427, respectively, in each period. Class B dividends declared during the fourth quarter of 2011 and the first quarter of 2012 were paid during the first quarter of 2012 totaling $96,356. As of June 30, 2012, the Company had not paid any dividends to holders of the Class A shares. Concurrent with the completion of the Initial Public Offering, all 1,030,700 shares of the Company's Class B common stock were converted to Class A common stock on a one-for-one basis. The Class A common stock is now referred to as the common stock.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS –

UNAUDITED — CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

The following are reconciliations of the numerators and denominators used to compute the Company's basic and diluted distributed and undistributed earnings (loss) per common share as reported for the three and six months ended June 30, 2012 and 2011 (in thousands, except per share amounts).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Net income (loss) - numerator				
Net (loss) income	$ (6,676)	$ 7,152	$ (2,875)	$(20,443)
Less dividends to Class B shareholders – distributed earnings	—	(69)	(28)	(138)
Undistributed (loss) earnings	$ (6,676)	$ 7,083	$ (2,903)	$(20,581)
Weighted average common shares outstanding – denominator				
Basic				
Class A	55,271	41,667	52,434	41,646
Class B	—	1,031	210	1,031
Total	55,271	42,698	52,644	42,677
Diluted				
Class A				
Weighted average common shares outstanding for basic earnings (loss) per share	55,271	41,667	52,434	41,646
Dilutive effect of options and restricted stock units	—	115	—	—
Class A weighted average common shares outstanding - diluted	55,271	41,782	52,434	41,646
Class B				
Weighted average common shares outstanding – no associated dilutive shares	—	1,031	210	1,031
Total diluted weighted average common shares outstanding	55,271	42,813	52,644	42,677

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS –

UNAUDITED — CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Earnings (loss) per common share				
Basic				
Class A				
Distributed earnings	$ —	$ —	$ —	$ —
Undistributed (loss) earnings	$ (0.12)	$ 0.17	$ (0.06)	$ (0.48)
Total	$ (0.12)	$ 0.17	$ (0.06)	$ (0.48)
Class B				
Distributed earnings	$ —	$ 0.06	$ 0.13	$ 0.13
Undistributed (loss) earnings	$ —	$ 0.17	$ (0.06)	$ (0.48)
Total	$ —	$ 0.23	$ 0.07	$ (0.35)
Diluted				
Class A				
Distributed earnings	$ —	$ —	$ —	$ —
Undistributed (loss) earnings	$ (0.12)	$ 0.17	$ (0.06)	$ (0.48)
Total	$ (0.12)	$ 0.17	$ (0.06)	$ (0.48)
Class B				
Distributed earnings	$ —	$ 0.06	$ 0.13	$ 0.13
Undistributed (loss) earnings	$ —	$ 0.17	$ (0.06)	$ (0.48)
Total	$ —	$ 0.23	$ 0.07	$ (0.35)

A total of 1,293,568 options to purchase the Company's Class A common stock and 139,963 restricted stock units were excluded from the calculations above for the three and six months ended June 30, 2012 because their effects were anti-dilutive. Additionally, 231,683 restricted shares, which are participating securities, were excluded from the calculations above for the three and six months ended June 30, 2012 as the security holders do not have the obligation to share in the losses of the Company. A total of 1,076,000 options to purchase shares of the Company's Class A common stock were excluded from the calculations above for the six months ended June 30, 2011 because their effects were anti-dilutive. These options were included in the calculations above for the three months ended June 30, 2011.

Fair Value Measurements

The Company measures and reports certain assets and liabilities on a fair value basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company follows Financial Accounting Standards Board ("FASB") guidance establishing a fair value hierarchy that prioritizes the inputs to valuation methods used to measure fair value.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS –

UNAUDITED — CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

Recent Accounting Pronouncements

Balance Sheet. In December 2011, the FASB issued Accounting Standards Update, or ASU, 2011-11, *Balance Sheet*. The requirements amend the disclosure requirements related to offsetting in Accounting Standard's Codification, or ASC, 210-20-50. The amendments require enhanced disclosures by requiring improved information about financial instruments and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. The adoption of ASU 2011-11 is not expected to have a material effect on the Company's consolidated financial statements, but may require certain additional disclosures. The amendments in ASU 2011-11 are to be applied for annual reporting periods beginning on or after January 1, 2013 and are to be applied retrospectively for all periods presented.

Fair Value. In May 2011, the FASB issued ASU 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS*. ASU 2011-04 amends ASC 820, *Fair Value Measurements*, providing a consistent definition and measurement of fair value, as well as similar disclosure requirements between U.S. GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles, clarifies the application of existing fair value measurements and expands the ASC 820 disclosure requirements, particularly for Level 3 fair value measurements. The Company adopted ASU 2011-04 on January 1, 2012; adoption did not have a material effect on the Company's consolidated financial statements, but did require additional disclosures.

NOTE 3 - ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company's asset retirement obligations for the six months ended June 30, 2012 (in thousands).

Beginning asset retirement obligations	$4,269
Liabilities incurred during period	326
Liabilities settled during period	—
Accretion expense	111
Ending asset retirement obligations	$4,706

At June 30, 2012, approximately $0.3 million of the Company's asset retirement obligations were classified as current liabilities and included in "accrued liabilities" in the Company's unaudited condensed consolidated balance sheet (see Note 11).

NOTE 4 - REVOLVING CREDIT AGREEMENT

In December 2011, the Company amended and restated its senior secured revolving credit agreement ("Credit Agreement") for which Comerica Bank serves as administrative agent. This amendment increased the maximum facility amount from $150 million to $400 million. Borrowings under the Credit Agreement are limited to the lesser of $400 million or the borrowing base. At June 30, 2012, the borrowing base was $125 million. The Credit Agreement matures in December 2016.

MRC Energy Company is the borrower under the Credit Agreement and borrowings are secured by mortgages on substantially all of the Company's oil and natural gas properties and by the equity interests of all of MRC Energy Company's wholly owned subsidiaries, which are also guarantors. In addition, all obligations under the Credit Agreement are guaranteed by Matador Resources Company, the parent corporation. Various commodity hedging agreements with Comerica Bank (or an affiliate thereof) are also secured by the collateral and guaranteed by the subsidiaries of MRC Energy Company.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS –

UNAUDITED — CONTINUED

NOTE 4 - REVOLVING CREDIT AGREEMENT - Continued

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of the Company's proved oil and natural gas reserves, but also on external factors, such as the lenders' lending policies and the lenders' estimates of future oil and natural gas prices, over which the Company has no control. At December 31, 2011, the borrowing base was $125 million and we had $113 million in outstanding borrowings under the Credit Agreement. In January 2012, the Company borrowed an additional $10 million to finance a portion of its working capital requirements and capital expenditures, bringing the then outstanding revolving borrowings under the Credit Agreement to $123 million. Following the completion of the Initial Public Offering in February 2012, the Company used a portion of the net proceeds to repay the then outstanding $123 million under the Credit Agreement in full, at which time the borrowing base was reduced to $100 million. On February 28, 2012, the borrowing base was increased to $125 million pursuant to a special borrowing base redetermination made at the Company's request. The borrowing base increase was determined by the lenders based upon, among other items, the increase in the Company's oil and natural gas reserves at December 31, 2011.

Between March 1, 2012 and June 30, 2012, the Company borrowed $60 million under the Credit Agreement to finance a portion of its working capital requirements and capital expenditures. At June 30, 2012, the Company had $60 million in borrowings outstanding under the Credit Agreement, approximately $1.3 million in outstanding letters of credit issued pursuant to the Credit Agreement and approximately $63.7 million available for additional borrowings. At June 30, 2012, the Company's outstanding borrowings bore interest at an effective rate of 3.3% per annum.

Both the Company and the lenders may each request an unscheduled redetermination of the borrowing base twice at any time during the first year of the Credit Agreement and once between scheduled redetermination dates thereafter. The Company requested one such unscheduled redetermination in February 2012. In the event of a borrowing base increase, the Company is required to pay a fee to the lenders equal to a percentage of the amount of the increase, which will be determined based on market conditions at the time of the borrowing base increase. If the borrowing base were to be less than the outstanding borrowings under the Credit Agreement at any time, the Company would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or to repay the deficit in equal installments over a period of six months.

If the Company borrows funds as a base rate loan, such borrowings will bear interest at a rate equal to the higher of (i) the weighted average of rates used in overnight federal funds transactions with members of the Federal Reserve System plus 1.0% or (ii) the prime rate for Comerica Bank then in effect or (iii) a daily adjusted LIBOR rate plus 1.0% plus, in each case, an amount from 0.375% to 1.75% of such outstanding loan depending on the level of borrowings under the agreement. If the Company borrows funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (i) the quotient obtained by dividing (A) the interest rate appearing on Page BBAM of the Bloomberg Financial Markets Information Service by (B) a percentage equal to 100% minus the maximum rate during such interest calculation period at which Comerica Bank is required to maintain reserves on Eurocurrency Liabilities (as defined in Regulation D of the Board of Governors of the Federal Reserve System) plus (ii) an amount from 1.375% to 2.75% of such outstanding loan depending on the level of borrowings under the agreement. The interest period for Eurodollar borrowings may be one, two, three or six months as designated by the Company. A facility fee of 0.375% to 0.50%, depending on the amounts borrowed, is also paid quarterly in arrears. The Company includes this facility fee and any loan amortization costs in its interest rate calculations and related disclosures.

Key financial covenants under the Credit Agreement require the Company to maintain (1) a current ratio, which is defined as consolidated total current assets plus the unused availability under the Credit Agreement divided by consolidated total current liabilities, of 1.0 or greater measured at the end of each fiscal quarter beginning March 31, 2012 and (2) a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.0 or less.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS –

UNAUDITED — CONTINUED

NOTE 4 - REVOLVING CREDIT AGREEMENT - Continued

Subject to certain exceptions, the Credit Agreement contains various covenants that limit the Company's, along with its subsidiaries', ability to take certain actions, including, but not limited to, the following:

- incur indebtedness or grant liens on any of its assets;
- enter into commodity hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates; and
- engage in certain asset dispositions, including a sale of all or substantially all of the Company's assets.

If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of the borrowings and exercise other rights and remedies. Events of default include, but are not limited to, the following events:

- failure to pay any principal or interest on the notes or any reimbursement obligation under any letter of credit when due or any fees or other amount within certain grace periods;
- failure to perform or otherwise comply with the covenants and obligations in the Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;
- bankruptcy or insolvency events involving the Company or its subsidiaries; and
- a change of control, as defined in the Credit Agreement.

At June 30, 2012, the Company believes that it was in compliance with the terms of the Credit Agreement.

NOTE 5 - INCOME TAXES

The Company had a net loss for the three and six months ended June 30, 2012 and a net loss for the six months ended June 30, 2011. The Company established a valuation allowance at March 31, 2011 and retained a valuation allowance of approximately $2.8 million at June 30, 2011, due to uncertainties regarding the future realization of its deferred tax assets. As a result, there was no income tax expense recorded for the three months ended June 30, 2011.

During the first quarter of 2012, the Company recorded an adjustment to the estimated permanent differences between book and taxable income related to stock compensation expense in prior periods. The adjustment resulted in a charge to deferred tax assets and additional deferred income taxes of approximately $0.7 million which is reflected in the Company's statement of operations for the six months ended June 30, 2012. Although the amount may be considered material to the financial results for the six months ended June 30, 2012, the Company does not believe that the adjustment will have a material impact on the financial results for the year ended December 31, 2012.

NOTE 6 - STOCK-BASED COMPENSATION

Effective January 1, 2012, the Board of Directors adopted the 2012 Long-Term Incentive Plan (the "2012 Incentive Plan"). The 2012 Incentive Plan was also approved by the Company's shareholders at its Annual Meeting of Shareholders on June 7, 2012. The 2012 Incentive Plan provides for a maximum of four million shares of common stock in the aggregate that may be issued by the Company pursuant to grants of stock options, restricted stock, stock appreciation rights, restricted stock units and other performance awards. The persons eligible to receive awards under the 2012 Incentive Plan include employees, contractors, and outside directors of the Company. The primary purpose of the 2012 Incentive Plan is to attract and retain key employees, key contractors and outside directors of the Company.

In February 2012, the Company granted one of its executive officers the option to purchase 150,000 shares of its common stock at $12.00 per share. The award was classified as an equity award, vesting over a service period of approximately three years. The total grant date fair value of the option was approximately $1.1 million. The Company reversed previously recognized stock-based compensation expense related to this grant of approximately $70,000 at June 30, 2012, as the executive officer terminated his employment with the Company in July 2012, and therefore, the service condition requirement for this award will not be met.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS –

UNAUDITED — CONTINUED

NOTE 6 - STOCK-BASED COMPENSATION - Continued

On April 16, 2012, the Board of Directors approved an award of stock options, restricted stock and restricted stock units to both executive and non-executive employees under the 2012 Incentive Plan. Non-qualified options to purchase an aggregate of 472,318 shares of the Company's common stock at $10.49 per share were awarded; these options vest over four years. A total of 116,842 shares of time-lapse restricted stock was granted, and these shares also vest over four years. A total of 116,841 shares of performance-based restricted stock was granted. These shares vest based on the outcome of the Company's total shareholder return over a three-year period as compared to a designated peer group. This award may result in the issuance of an aggregate of up to 116,841 restricted stock units in addition to the restricted stock grants. If the minimum performance conditions are not met, however, this award may also result in no performance-based restricted stock being vested and no restricted stock units being issued. The grant date fair value of all of these awards is approximately $5.5 million.

On April 11, 2012 and June 29, 2012, the Company awarded 13,608 and 12,215 restricted stock units, respectively, to its Board of Directors and one advisor to the Board as payment for their services to the Company during the first and second quarters of 2012. The restricted stock units vest over three years and have an aggregate grant date fair value of approximately $0.3 million.

On April 11, 2012 and June 29, 2012, the Company issued 1,000 shares of common stock each (aggregate of 2,000 shares issued) to two advisors to the Board of Directors as payment for their services to the Company during the first and second quarters of 2012. The fair value of these awards was $11,020 and $10,740, respectively, which was recorded as an expense during the three months ended March 31, 2012 and June 30, 2012, respectively. On June 6, 2012, the Company issued 4,000 shares of common stock to a retiring director as payment for his services during the second quarter of 2012. The fair value of this award was $38,840, which was recorded as an expense during the three months ended June 30, 2012.

NOTE 7 - COMMON STOCK

On August 12, 2011, the Company filed a Form S-1 Registration Statement under the Securities Act of 1933 to commence the initial public offering of its common stock (the "Initial Public Offering"). The Company's Registration Statement (File 333-176263), as amended, was declared effective by the SEC on February 1, 2012. The underwriters for the Company's Initial Public Offering were RBC Capital Markets, LLC; Citigroup Global Markets, Inc.; Jefferies & Company, Inc.; Howard Weil Incorporated; Stifel, Nicolaus & Company, Incorporated; Simmons & Company International; Stephens Inc.; and Comerica Securities, Inc. On February 2, 2012, shares of the Company's common stock began trading on the New York Stock Exchange under the symbol "MTDR" at an initial offering price of $12.00 per share.

Pursuant to its Prospectus dated February 1, 2012, the Company and the selling shareholders offered 13,333,334 shares of the Company's common stock for sale. The Company offered 11,666,667 shares of its common stock, and the selling shareholders offered 1,666,667 shares. On February 7, 2012, the Company closed the Initial Public Offering and issued 11,666,667 shares of its common stock pursuant to the Initial Public Offering.

The Company and the selling shareholders granted the underwriters the right to purchase up to an additional 2,000,000 shares of the Company's common stock at the initial offering price of $12.00 per share, less the underwriters' discounts and commissions, for a period of 30 days following the Initial Public Offering to cover over-allotments, with the Company offering 700,000 shares and the selling shareholders offering 1,300,000 shares. On March 2, 2012, the underwriters exercised their option to purchase an additional 1,550,000 shares, including the purchase of 542,500 shares from the Company and the purchase of 1,007,500 shares from the selling shareholders. On March 7, 2012, the Company closed this transaction and issued 542,500 shares of its common stock pursuant to the underwriters' exercise of the over-allotment.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS –

UNAUDITED — CONTINUED

NOTE 7 - COMMON STOCK - Continued

Pursuant to the Initial Public Offering and the over-allotment, the Company issued a total of 12,209,167 shares of its common stock at $12.00 per share. The Company received cash proceeds of approximately $136.6 million from this transaction, net of underwriting discounts and commissions. The Company did not receive any proceeds from the sale of shares of its common stock by the selling shareholders. The underwriters received underwriting discounts and commissions totaling approximately $9.9 million, and the Company incurred additional costs of approximately $3.5 million in connection with the offering, which amounted to total fees and costs of approximately $13.4 million, of which approximately $2.1 million was incurred in a prior period. On February 8, 2012, the Company used a portion of the net proceeds of the offering to repay the $123.0 million in borrowings then outstanding under its Credit Agreement in full. The Company used the remaining net proceeds of the offering to fund a portion of its 2012 capital expenditures.

Concurrent with the completion of the Initial Public Offering, all 1,030,700 shares of the Company's Class B common stock were converted to Class A common stock on a one-for-one basis. In addition, in February 2012, the Company issued an additional 295,500 shares of its Class A common stock pursuant to the exercise of stock options and received net proceeds of $2.7 million. The Class A common stock is now referred to as the common stock.

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS

From time to time, the Company uses derivative financial instruments to mitigate its exposure to commodity price risk associated with oil and natural gas prices. These instruments consist of put and call options in the form of costless collars. The Company records derivative financial instruments on its balance sheet as either an asset or a liability measured at fair value. The Company has elected not to apply hedge accounting for its existing derivative financial instruments. As a result, the Company recognizes the change in derivative fair value between reporting periods currently in its consolidated statement of operations as an unrealized gain or loss. The fair value of the Company's derivative financial instruments is determined using purchase and sale information available for similarly traded securities. The Company has evaluated the credit standing of its single counterparty, Comerica Bank, in determining the fair value of these derivative financial instruments.

The Company has entered into various costless collar contracts to mitigate its exposure to fluctuations in oil prices on a portion of its future expected oil production, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss to the Company pursuant to any of these transactions is the arithmetic average of the settlement prices for the NYMEX West Texas Intermediate oil futures contract for the first nearby month corresponding to the calculation period's calendar month. When the settlement price is below the price floor established by these collars, the Company receives from Comerica Bank, as counterparty, an amount equal to the difference between the settlement price and the price floor multiplied by the contract oil volume. When the settlement price is above the price ceiling established by these collars, the Company pays to Comerica, as counterparty, an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract oil volume.

The Company has entered into various costless collar transactions to mitigate its exposure to fluctuations in natural gas prices on a portion of its future expected natural gas production, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss to the Company pursuant to any of these transactions is the settlement price for the NYMEX Henry Hub natural gas futures contract for the delivery month corresponding to the calculation period's calendar month for the last day of that contract period. When the settlement price is below the price floor established by these collars, the Company receives from Comerica Bank, as counterparty, an amount equal to the difference between the settlement price and the price floor multiplied by the contract natural gas volume. When the settlement price is above the price ceiling established by these collars, the Company pays to Comerica, as counterparty, an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract natural gas volume.

At June 30, 2012, the Company had multiple costless collar contracts open and in place to mitigate its exposure to oil and natural gas price volatility, each with a specific term (calculation period), notional quantity (volume hedged) and price floor and ceiling. Each contract is set to expire at varying times during 2012, 2013 and 2014.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS –

UNAUDITED — CONTINUED

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The following is a summary of the Company's open costless collar contracts for oil and natural gas at June 30, 2012.

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (thousands)
Oil	07/01/2012 - 12/31/2012	20,000	90.00	104.20	$ 784
Oil	07/01/2012 - 12/31/2012	10,000	90.00	108.00	407
Oil	07/01/2012 - 12/31/2012	10,000	90.00	109.50	411
Oil	07/01/2012 - 12/31/2012	20,000	90.00	111.00	829
Oil	07/01/2012 - 12/31/2012	20,000	90.00	111.90	832
Oil	07/01/2012 - 12/31/2012	20,000	95.00	116.00	1,274
Oil	07/01/2012 - 03/31/2013	20,000	90.00	110.00	1,294
Oil	01/01/2013 - 12/31/2013	20,000	85.00	102.25	938
Oil	01/01/2013 - 12/31/2013	20,000	90.00	115.00	2,065
Oil	01/01/2013 - 12/31/2013	20,000	85.00	110.40	1,356
Oil	01/01/2013 - 12/31/2013	20,000	85.00	108.80	1,292
Oil	01/01/2013 - 06/30/2014	8,000	90.00	114.00	1,258
Oil	01/01/2013 - 06/30/2014	12,000	90.00	115.50	1,930
Total Oil					$ 14,670

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas	07/01/2012 - 12/31/2012	300,000	4.50	5.60	$ 2,801
Natural Gas	07/01/2012 - 12/31/2012	150,000	4.25	6.17	1,187
Natural Gas	07/01/2012 - 12/31/2012	70,000	2.50	3.34	(26)
Natural Gas	07/01/2012 - 07/31/2013	150,000	4.50	5.75	2,557
Natural Gas	07/01/2012 - 12/31/2013	100,000	3.00	3.83	(63)
Total Natural Gas					6,456
Total open costless collar contracts					$ 21,126

The following table summarizes the location and aggregate fair value of all derivative financial instruments recorded in the consolidated balance sheets for the periods presented (in thousands). These derivative financial instruments are not designated as hedging instruments.

Type of Instrument	Location in Balance Sheet	June 30, 2012	December 31, 2011
Derivative Instrument			
Oil	Current assets: Derivative instruments	$ 9,595	$ —
Oil	Other assets: Derivative instruments	5,075	—
Oil	Current liabilities: Derivative instruments	—	(171)
Oil	Long-term liabilities: Derivative instruments	—	(383)
Natural Gas	Current assets: Derivative instruments	6,438	8,989
Natural Gas	Other assets: Derivative instruments	18	847
Total		$21,126	$ 9,282

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS –

UNAUDITED — CONTINUED

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The following table summarizes the location and aggregate fair value of all derivative financial instruments recorded in the consolidated statements of operations for the periods presented (in thousands). These derivative financial instruments are not designated as hedging instruments.

Type of Instrument	Location in Statement of Operations	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Derivative Instrument					
Oil	Revenue: Realized gain on derivatives	$ 719	$ —	$ 719	$ —
Natural Gas	Revenues: Realized gain on derivatives	3,994	952	7,057	2,802
Realized gain on derivatives		4,713	952	7,776	2,802
Oil	Revenues: Unrealized gain on derivatives	20,483	—	15,223	—
Natural Gas	Revenues: Unrealized (loss) gain on derivatives	(5,369)	332	(3,379)	(1,336)
Unrealized gain (loss) on derivatives		15,114	332	11,844	(1,336)
Total		$19,827	$1,284	$19,620	$ 1,466

NOTE 9 - FAIR VALUE MEASUREMENTS

The Company measures and reports certain financial and non-financial assets and liabilities on a fair value basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements are classified and disclosed in one of the following categories.

Level 1 Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Active markets are considered to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 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. This category includes those derivative instruments that are valued using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.

Level 3 Unobservable inputs that are not corroborated by market data. This category is comprised of financial and non-financial assets and liabilities whose fair value is estimated based on internally developed models or methodologies using significant inputs that are generally less readily observable from objective sources.

Financial and non-financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

At June 30, 2012 and December 31, 2011, the carrying values reported on the consolidated balance sheets for cash and cash equivalents, accounts receivable, prepaid expenses, accounts payable, accrued liabilities, royalties payable and other current liabilities approximate their fair values due to their short-term maturities and are classified at Level 1.

At June 30, 2012 and December 31, 2011, the carrying value of borrowings under the Credit Agreement approximates fair value as it is subject to short-term floating interest rates that reflect market rates available to the Company at the time and is classified at Level 2.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS –

UNAUDITED — CONTINUED

NOTE 9 - FAIR VALUE MEASUREMENTS - Continued

The following tables summarize the valuation of the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis in accordance with the classifications provided above as of June 30, 2012 and December 31, 2011 (in thousands).

Description	Fair Value Measurements at June 30, 2012 using			
	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Certificates of deposit	$ —	$ 266	$ —	$ 266
Oil and natural gas derivatives	—	21,126	—	21,126
Total	$ —	$21,392	$ —	$21,392

Description	Fair Value Measurements at December 31, 2011 using			
	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Certificates of deposit	$ —	$ 1,335	$ —	$ 1,335
Oil and natural gas derivatives	—	9,836	—	9,836
Oil and natural gas derivatives	—	(554)	—	(554)
Total	$ —	$10,617	$ —	$10,617

Additional disclosures related to derivative financial instruments are provided in Note 8. For purposes of fair value measurement, the Company determined that certificates of deposit and derivative financial instruments (e.g., oil and natural gas derivatives) should be classified at Level 2.

The Company accounts for additions to asset retirement obligations and lease and well equipment inventory at fair value on a non-recurring basis. The following tables summarize the valuation of the Company's assets and liabilities that were accounted for at fair value on a non-recurring basis for the periods ended June 30, 2012 and December 31, 2011 (in thousands).

Description	Fair Value Measurements for the period ended June 30, 2012 using			
	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$ —	$ —	$ (326)	$ (326)
Total	$ —	$ —	$ (326)	$ (326)

Description	Fair Value Measurements for the period ended December 31, 2011 using			
	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$ —	$ —	$ (187)	$ (187)
Lease and well equipment inventory	—	—	1,343	1,343
Total	$ —	$ —	$ 1,156	$ 1,156

For purposes of fair value measurement, the Company determined that the additions to asset retirement obligations should be classified at Level 3. The Company recorded additions to asset retirement obligations of $325,643 for the six months ended June 30, 2012 and $186,873 for the year ended December 31, 2011.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS –

UNAUDITED — CONTINUED

NOTE 9 - FAIR VALUE MEASUREMENTS - Continued

For purposes of fair value measurement, the Company determined that lease and well equipment inventory should be classified as Level 3. In 2011, the Company recorded an impairment to some of its equipment held in inventory consisting primarily of drilling rig parts of $17,500 and pipe and other equipment of $22,276; no impairment to any equipment was recorded for the three and six months ended June 30, 2012. The Company periodically obtains estimates of the market value of its equipment held in inventory from an independent third-party contractor or seller of similar equipment and uses these estimates as a basis for its measurement of the fair value of this equipment.

NOTE 10 - COMMITMENTS AND CONTINGENCIES

Office Lease

The Company's corporate headquarters are located in 28,743 square feet of office space at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas. In April 2011, the Company agreed to a restated third amendment to its office lease agreement, in which the office space was increased to 28,743 square feet and the term of the lease was extended from July 1, 2011 to June 30, 2022. The effective base rent over the term of the new lease extension is $19.75 per square foot per year. The base rate escalates several times during the course of the lease, specifically in July 2015, July 2017, July 2019 and July 2020.

Other Commitments

During the first quarter of 2012, the Company extended one of its drilling rig contracts in South Texas for an additional nine months. The Company terminated its second contract with no termination penalty and entered into a new contract for a higher performance rig with the same drilling rig contractor for a period of one year. Drilling operations under these two contracts began in early March 2012. Should the Company elect to terminate one or both contracts and if the drilling contractor were unable to secure work for one or both rigs or if the drilling contractor were unable to secure work for one or both rigs at the same daily rate being charged to the Company prior to the end of their respective terms, the Company would incur termination obligations. The Company's maximum outstanding aggregate termination obligations under these contracts were approximately $6.7 million at June 30, 2012.

At June 30, 2012, the Company had outstanding commitments to participate in the drilling and completion of various non-operated wells, primarily in the Haynesville shale. The Company's working interests in these wells are small, and most of these wells were in progress at June 30, 2012. If all of these wells are drilled and completed, the Company's minimum outstanding aggregate commitments at June 30, 2012 for its participation in these wells were approximately $2.8 million, and the Company expects these costs to be incurred in the next twelve months.

Legal Proceedings

Cynthia Fry Peironnet, et al. v. Matador Resources Company. The Company is involved in a dispute over a mineral rights lease involving certain acreage in Louisiana. The dispute regards an extension of the term of a lease in Caddo Parish, Louisiana (the "Lease") where the Company has drilled or participated in the drilling of both Cotton Valley and Haynesville shale wells. At issue are the deep rights below the Cotton Valley formation on approximately 1,805 gross acres where the Company has the right to participate for up to a 25% working interest, and also retains a small overriding royalty interest, in Haynesville shale wells drilled in units that include portions of the acreage. The Company's total net revenue and overriding royalty interests in several non-operated Haynesville shale wells previously drilled on this acreage range from approximately 2% to 23%, and only portions of these interests are attributable to this acreage. The sum of the Company's overriding royalty and net revenue interests attributable to this acreage from Haynesville wells previously drilled on this acreage comprises less than one net well.

NOTE 10 - COMMITMENTS AND CONTINGENCIES - Continued

The plaintiffs brought this claim against the Company on May 15, 2008 in the First Judicial District Court, Caddo Parish, Louisiana (the "Trial Court"). The plaintiffs sought (i) reformation or recission of the lease extension, (ii) an accounting for additional royalty, (iii) monetary damages and (iv) attorney's fees. During the pendency of the case in the Trial Court, the Company settled with one lessor who owned a 1/6th undivided interest in the minerals. Since May 2008, the Trial Court has rendered multiple rulings in the favor of the Company, including a unanimous jury verdict in favor of the Company in the fall of 2010. Final judgment of the Trial Court was rendered in favor of Matador on June 6, 2011. On August 1, 2012, the Louisiana Second Circuit of Appeal (the "Court of Appeal") affirmed in part and reversed in part the judgment of the Trial Court and remanded the case to the Trial Court for determination of damages. The Court of Appeal affirmed the Trial Court with respect to the 1/6th royalty owner that settled and also affirmed that the Company's lease extension was unambiguous. Nonetheless, the Court of Appeal reformed the lease extension to cover only approximately 169 gross acres, holding that the deep rights covering the remaining 1,636 gross acres had expired.

The Company believes that the facts of the case and the applicable law do not support the Court of Appeal's judgment and it intends to vigorously pursue its rights to have the Trial Court's judgment reinstated. Although the Company does not consider a loss resulting from this dispute to be probable, it is reasonably possible that the Company could incur a loss as a result of the continuing litigation of this matter. The Company currently estimates that a reasonable range of potential loss is zero to $6 million.

The Company is a defendant in several other lawsuits encountered in the ordinary course of its business, none of which, in the opinion of management, will have a material adverse impact on the Company's financial position, results of operations or cash flows.

NOTE 11 - SUPPLEMENTAL DISCLOSURES

Accrued Liabilities

The following table summarizes the Company's current accrued liabilities at June 30, 2012 and December 31, 2011 (in thousands).

	June 30, 2012	December 31, 2011
Accrued evaluated and unproved and unevaluated property costs	$29,653	$ 18,185
Accrued support equipment and facilities costs	—	216
Accrued cost to issue equity	—	332
Accrued stock-based compensation	1,276	2,860
Accrued lease operating expenses	2,272	575
Accrued interest on borrowings under Credit Agreement	118	—
Accrued asset retirement obligations	343	334
Other	2,597	2,937
Total accrued liabilities	$36,259	$ 25,439

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS –

UNAUDITED — CONTINUED

NOTE 11 - SUPPLEMENTAL DISCLOSURES - Continued

Supplemental Cash Flow Information

The following table provides supplemental disclosures of cash flow information for the six months ended June 30, 2012 and 2011 (in thousands).

	Six Months Ended June 30,	
	2012	2011
Cash paid for interest expense, net of amounts capitalized	$ 226	$ 36
Asset retirement obligations related to mineral properties	293	(22)
Asset retirement obligations related to support equipment and facilities	33	17
Increase (decrease) in liabilities for oil and natural gas properties capital expenditures	8,995	(12,587)
(Decrease) increase in liabilities for support equipment and facilities	(215)	71
Increase in accounts receivable for oil and natural gas properties capital expenditures	—	45
Issuance of restricted stock units for Board and advisor services	10	—
Issuance of common stock for Board and advisor services	61	99
Decrease in liabilities for accrued cost to issue equity	(331)	(291)
Stock-based compensation expense recognized as liability	(491)	115
Transfer of costs to support equipment and facilities from oil and natural gas properties capital expenditures	—	129
Transfer of inventory from oil and natural gas properties	—	(157)
Receivable for inventory from other joint interest owners	—	(157)

NOTE 12 - SUBSEQUENT EVENTS

In July and August 2012, the Company borrowed an additional $30.0 million under the Credit Agreement to finance a portion of its working capital requirements and capital expenditures. At August 14, 2012, the Company had $90.0 million in borrowings outstanding under the Credit Agreement and approximately $1.3 million in outstanding letters of credit issued pursuant to the Credit Agreement.

In August 2012, the Company committed to participating in a non-operated Eagle Ford shale well in Wilson County, Texas. If the well is drilled and completed as planned, the Company will have a minimum commitment for its participation in the well of approximately $2.4 million. At August 14, 2012, drilling operations are in progress on this well.

On August 10, 2012, the Company acquired 4,911 gross and 2,873 net acres prospective for the Wolfcamp and Bone Spring formations in the Delaware Basin in Loving County, Texas. The Company paid approximately $8.6 million to acquire this acreage.

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes thereto contained herein and in our Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC, along with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in such Form 10-K. The Annual Report is accessible on the SEC's website at www.sec.gov and on our website at www.matadorresources.com. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with "Cautionary Note Regarding Forward-Looking Statements" below for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

In this Quarterly Report on Form 10-Q, references to "we," "our" or "the Company" refer to Matador Resources Company and its subsidiaries before the completion of our corporate reorganization on August 9, 2011 and Matador Holdco, Inc. and its subsidiaries after the completion of our corporate reorganization on August 9, 2011. Prior to August 9, 2011, Matador Holdco, Inc. was a wholly owned subsidiary of Matador Resources Company, now known as MRC Energy Company. Pursuant to the terms of our corporate reorganization, former Matador Resources Company became a wholly owned subsidiary of Matador Holdco, Inc. and changed its corporate name to MRC Energy Company, and Matador Holdco, Inc. changed its corporate name to Matador Resources Company.

Unless the context otherwise requires, the term "common stock" refers to shares of our common stock after the conversion of our Class B common stock into Class A common stock upon the consummation of our Initial Public Offering on February 7, 2012, as the Class A common stock became the only class of common stock authorized, and the term "Class A common stock" refers to shares of our Class A common stock prior to the automatic conversion of our Class B common stock into Class A common stock upon the consummation of our Initial Public Offering.

For certain oil and natural gas terms used in this report, please see the "Glossary of Oil and Natural Gas Terms" included with our Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC.

Cautionary Note Regarding Forward-Looking Statements

Certain statements in this Quarterly Report on Form 10-Q constitute "forward-looking statements" within the meaning of applicable U.S. securities legislation. Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future, by us or on our behalf. Such statements are generally identifiable by the terminology used such as "anticipate," "believe," "continue," "could," "estimate," "expect," "intend," "may," "might," "potential," "predict," "project," "should" or other similar words.

By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: changes in oil or natural gas prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, and the other factors discussed below and elsewhere in this report and in other documents that we file with or furnish to the SEC, all of which are difficult to predict. Forward-looking statements may include statements about:

- our business strategy;
- our reserves and the present value thereof;
- our technology;
- our cash flows and liquidity;
- our financial strategy, budget, projections and operating results;
- our oil and natural gas realized prices;
- the timing and amount of future production of oil and natural gas;
- the availability of drilling and production equipment;
- the availability of oil field labor;
- the amount, nature and timing of capital expenditures, including future exploration and development costs;
- the availability and terms of capital;

- our drilling of wells;
- government regulation and taxation of the oil and natural gas industry;
- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- our costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- competition in the oil and natural gas industry;
- the effectiveness of our risk management and hedging activities;
- environmental liabilities;
- counterparty credit risk;
- developments in oil-producing and natural gas-producing countries;
- our future operating results;
- our estimated future reserves and the present value thereof;
- our plans, objectives, expectations and intentions contained in this report that are not historical; and
- other factors discussed in our Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity, achievements or financial condition.

You should not place undue reliance on any forward-looking statement and should recognize that the statements are predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward- looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We do not intend to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements except as required by law.

Overview

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with a particular emphasis on oil and natural gas shale plays and other unconventional resource plays. Our current operations are located primarily in the Eagle Ford shale play in South Texas and the Haynesville shale play in Northwest Louisiana and East Texas. We expect the majority of our near-term capital expenditures will focus on increasing our production and reserves from the Eagle Ford shale play. We believe our interests in the Eagle Ford shale play will enable us to create a more balanced commodity portfolio through the drilling of locations that are prospective for oil and liquids. In addition to these primary operating areas, we have acreage positions in Southeast New Mexico and West Texas and in Southwest Wyoming and adjacent areas of Utah and Idaho where we continue to identify new oil and gas prospects.

During the first six months of 2012, our operations were primarily focused on the exploration and development of our Eagle Ford shale properties in South Texas, as we continued executing our plan to significantly increase our oil production and oil reserves during 2012. During the six months ended June 30, 2012, we completed and began producing oil and natural gas from 12 gross/11.8 net operated and 1 gross/0.2 net non-operated Eagle Ford shale wells. We also completed and began producing natural gas from 14 gross/0.6 net non-operated Haynesville shale wells. We had two contracted drilling rigs operating in South Texas throughout the first six months of 2012 (except for a brief period near the end of the second quarter where we added a third rig to execute a two-well contract), and all of our operated drilling and completion activities were focused on the Eagle Ford shale. At August 14, 2012, we have two contracted drilling rigs operating in South Texas: one in LaSalle County and one in Karnes County.

In the second quarter of 2012 specifically, our activities were almost entirely focused on our Eagle Ford shale properties. During the three months ended June 30, 2012, we completed and began producing oil and/or natural gas from 6 gross/5.9 net operated and 1 gross/0.2 net non-operated Eagle Ford shale wells. We completed one well on our Northcut lease in LaSalle County, four wells on our Danysh/Pawelek lease in Karnes County and one well on our Glasscock Ranch lease in Zavala County, all in the Eagle Ford shale. Three of the wells on the Danysh/Pawelek lease began producing at various times during the month of June 2012, and the Glasscock Ranch #1H well began producing at the very end of June. As a result, these four wells did not contribute fully to our second quarter production volumes.

Our average daily production for the three months ended June 30, 2012 was approximately 8,740 BOE per day, including approximately 3,130 Bbl of oil per day and 33.6 MMcf of natural gas per day, as compared to approximately 8,000 BOE per day, including 560 Bbl of oil per day and 44.6 MMcf of natural gas per day for the three months ended June 30, 2011. Both the average total daily production and the average daily oil production for the second quarter of 2012 were the best quarterly figures in our history. Our average daily oil production of 3,130 Bbl of oil per day during the second quarter of 2012 was an increase of about 42% from an average daily production of approximately 2,200 Bbl of oil per day during the first quarter of 2012 and an increase of almost six-fold from an average daily production of approximately 560 Bbl of oil per day in the second quarter of 2011. Our average daily production for the six months ended June 30, 2012 was approximately 8,380 BOE per day, including approximately 2,670 Bbl of oil per day and 34.3 MMcf of natural gas per day, as compared to approximately 7,160 BOE per day, including approximately 390 Bbl of oil per day and 40.8 MMcf of natural gas per day for the six months ended June 30, 2011. Our total oil production increased almost seven-fold to approximately 485 MBbl of oil during the first six months of 2012 from approximately 70 MBbl of oil during the first six months of 2011. This increased oil production is a direct result of our ongoing drilling operations in the Eagle Ford shale. Oil production comprised approximately 36% and 32% of our total production (using a conversion ratio of one Bbl of oil per six Mcf of natural gas) for the three and six months ending June 30, 2012, respectively, as compared to approximately 7% and 5% of our total production for the three and six months ended June 30, 2011.

Our oil and natural gas revenues were approximately $65.2 million, or an increase of about 89%, for the six months ended June 30, 2012 as compared to $34.6 million for the six months ended June 30, 2011. Our oil revenues increased almost eight-fold to $51.0 million for the six months ended June 30, 2012 as compared to $6.8 million for the six months ended June 30, 2011. Our oil and natural gas revenues of $65.2 million for the first six months of 2012 were 97% of our total oil and natural gas revenues of $67.0 million reported for all of 2011. Our Adjusted EBITDA increased by approximately $23.8 million to approximately $49.3 million, or an increase of approximately 93%, for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. This increase in our Adjusted EBITDA is primarily attributable to the increase in our oil production and the associated increase in our oil and natural gas revenues for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. Our Adjusted EBITDA of $49.3 million for the first six months of 2012 was 99% of our Adjusted EBITDA of $49.9 million reported for all of 2011.

Our estimated proved oil reserves increased almost eight-fold to approximately 6.7 million Bbl of oil at June 30, 2012 from approximately 0.9 million Bbl of oil at June 30, 2011, based on the reserves audit by our independent reservoir engineers, Netherland, Sewell & Associates, Inc. At June 30, 2012, we had approximately 19.1 million BOE of estimated total proved reserves, including approximately 6.7 million Bbl of oil and 73.9 Bcf of natural gas, with a PV-10 of $303.4 million and a Standardized Measure of $281.5 million. At June 30, 2012, 64% of our estimated proved reserves were proved developed reserves, 35% of our estimated proved reserves were oil and 65% of our estimated proved reserves were natural gas. At June 30, 2011, based on the reserves audit by our independent reservoir engineers, we had approximately 26.3 million BOE of estimated total proved reserves, including 0.9 million barrels of oil and 152.5 Bcf of natural gas, with a PV-10 of $144.4 million and a Standardized Measure of $134.2 million. At June 30, 2011, 34% of our estimated proved reserves were proved developed reserves, 3% of our estimated proved reserves were oil and 97% of our estimated proved reserves were natural gas.

The unweighted arithmetic average of the first-day-of-the-month natural gas prices was $3.146 per MMBtu for the period from July 2011 to June 2012 and $4.209 per MMBtu for the period from July 2010 to June 2011. These average prices were the natural gas prices used to estimate our natural gas reserves at June 30, 2012 and 2011, respectively. As a result of this decline in natural gas prices, at June 30, 2012, we removed 97.8 Bcf of previously classified proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana from our estimated total proved reserves, most of which were attributable to non-operated properties. As the leasehold acreage associated with these previously classified proved undeveloped natural gas reserves is held by production from existing Haynesville wells, however, these natural gas volumes remain available to be developed by us or the operator at a future time when natural gas prices improve, so long as the producing wells holding this acreage continue to produce as necessary to maintain held-by-production status.

During 2012, we intend to allocate 84% of our 2012 capital expenditure budget of $313.0 million to the exploration, development and acquisition of additional interests in the Eagle Ford shale play. Including these anticipated capital expenditures in the Eagle Ford shale, we plan to dedicate about 94% of our 2012 anticipated capital expenditure budget to opportunities prospective for oil and liquids production. At June 30, 2012, we have incurred approximately $146.7 million or about 47% of our 2012 estimated capital expenditures of $313.0 million. This includes approximately $12.3 million incurred to acquire additional leasehold acreage primarily in the Eagle Ford shale near our existing properties. During the first half of 2012, our drilling and completion costs for new wells have been less than we budgeted, although our costs for production facilities, pipelines and other infrastructure have exceeded our initial estimates. Overall, at June 30, 2012, we are executing our 2012 capital expenditure program largely as planned and remain within our anticipated capital expenditure budget for 2012. While we have budgeted $313.0 million for 2012, the aggregate amount of capital we will expend may fluctuate materially based on market conditions and our drilling results, as well as other opportunities we may encounter during the remainder of 2012.

During the six months ended June 30, 2012, natural gas prices have declined to their lowest levels in many years, with the NYMEX Henry Hub natural gas futures contract for the earliest delivery date ranging between a high of $3.10 per MMBtu in early January and a low of $1.91 per MMBtu in mid-April. We would not expect to drill any operated natural gas wells, except for natural gas wells in specific exploratory projects like the Meade Peak shale in Southwest Wyoming, until natural gas prices improved significantly from their recent levels. In addition, as a result of these low natural gas prices, several of our non-operated Haynesville shale wells were shut in for brief periods or produced less natural gas than we anticipated during the first six months of 2012 as the operators voluntarily curtailed a portion of the natural gas production from these wells.

As we continue to transition our operations to the Eagle Ford shale play in South Texas, we may face challenges associated with establishing operations in new areas and securing the necessary services to drill and complete wells and with securing the necessary pipeline and natural gas processing capabilities to transport, process and market the oil and natural gas that we produce. We may also incur higher than anticipated costs associated with establishing new operating infrastructure and facilities on our leases throughout the area. We believe we have successfully secured the necessary drilling and completion services for our current Eagle Ford operations. We did not experience difficulties in securing completion, and particularly hydraulic fracturing services, for any wells drilled during the first six months of 2012, although we experienced these problems at various times during 2011 in South Texas and may have such difficulties again in the future. We believe that maintaining reliable drilling and completion services and reducing drilling and completion costs will be essential to the successful development of the Eagle Ford shale play.

We did experience temporary pipeline interruptions from time to time during the three and six months ended June 30, 2012 associated with natural gas production from our Eagle Ford shale wells and have elected to either shut in wells for brief periods or to flare some of the natural gas we produced. We believe that these pipeline interruptions and capacity constraints are temporary and that additional oil and natural gas pipeline infrastructure currently being built throughout South Texas will help to alleviate these problems within 60 to 90 days. At August 14, 2012, we are negotiating a natural gas gathering, transportation and processing agreement, including firm transportation and processing, for most of our operated natural gas production in South Texas. We expect to complete this agreement during the third quarter of 2012. If we were required to shut in our production for long periods of time due to these pipeline interruptions, it could have a material adverse effect on our business, financial condition, results of operations and cash flows.

On February 2, 2012, our common stock began trading on the New York Stock Exchange, or NYSE, under the symbol "MTDR." Our general and administrative expenses have increased as a result of us operating as a public company. These increased expenses include costs associated with, among other items, legal and accounting support services, filing annual and quarterly reports with the SEC, investor relations activities, directors' fees, incremental directors' and officers' liability insurance costs, transfer and registrar agent fees and expenses associated with compliance with the Sarbanes-Oxley Act and other regulations. In addition, we have increased our staff size and compensation and incurred other ongoing general and administrative expenses necessary to maintain and grow a publicly traded exploration and production company. As a result, we believe that our general and administrative expenses for future periods may continue to increase. Our consolidated financial statements for future periods will reflect these increased expenses and affect the comparability of our financial statements with periods before the completion of our Initial Public Offering.

Initial Public Offering

We closed the Initial Public Offering of our common stock on February 7, 2012 and closed the over-allotment option on March 7, 2012. We issued 12,209,167 shares of common stock and 2,674,167 shares of common stock were sold by the selling shareholders. The shares were sold at a price to the public of $12.00 per share and we received cash proceeds of approximately $136.6 million from this transaction, net of underwriting discounts and commissions. We did not receive any proceeds from the sale of shares by the selling shareholders. The underwriters received underwriting discounts and commissions totaling approximately $9.9 million, and we incurred additional costs of approximately $3.5 million in connection with the offering, which amounted to total fees and costs of approximately $13.4 million. We used $123.0 million of the net proceeds to repay the then outstanding borrowings under our Credit Agreement. We used the remaining net proceeds to fund a portion of our 2012 capital expenditure requirements.

Estimated Proved Reserves

The following table sets forth our estimated proved oil and natural gas reserves at June 30, 2012 and 2011. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness by Netherland, Sewell & Associates, Inc., independent reservoir engineers. These reserves estimates were prepared in accordance with the SEC's rules for oil and natural gas reserves reporting. The estimated reserves shown are for proved reserves only and do not include any unproved reserves classified as probable or possible reserves that might exist for our properties, nor do they include any consideration that could be attributable to interests in unproved and unevaluated acreage beyond those tracts for which proved reserves have been estimated. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our total estimated proved reserves are estimated using a conversion ratio of one Bbl per six Mcf.

	At June 30,[1] 2012	2011
Estimated Proved Reserves Data: [2]		
Estimated proved reserves:		
Oil (MBbl)	6,728	878
Natural Gas (Bcf)	73.9	152.5
Total (MBOE) [3]	19,052	26,294
Estimated proved developed reserves:		
Oil (MBbl)	3,133	401
Natural Gas (Bcf)	54.0	51.1
Total (MBOE)	12,130	8,915
Percent developed	63.7%	33.9%
Estimated proved undeveloped reserves:		
Oil (MBbl)	3,595	478
Natural Gas (Bcf)	20.0	101.4
Total (MBOE)	6,922	17,380
PV-10[4] (in millions)	$ 303.4	$ 144.4
Standardized Measure[5] (in millions)	$ 281.5	$ 134.2

(1) Numbers in table may not total due to rounding.

(2) Our estimated proved reserves, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic averages of the first-day-of-the-month prices for the period from July 2011 to June 2012 were $92.17 per Bbl for oil and $3.146 per MMBtu for natural gas and for the period from July 2010 to June 2011 were $86.60 per Bbl for oil and $4.209 per MMBtu for natural gas. These prices were adjusted by property for quality, energy content, regional price differentials, transportation fees, marketing deductions and other factors affecting the price received at the wellhead.

(3) Thousands of barrels of oil equivalent, estimated using a conversion ratio of one Bbl per six Mcf.

(4) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. Our PV-10 at June 30, 2012 and 2011 may be reconciled to our Standardized Measure of discounted future net cash flows at such dates by reducing our PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at June 30, 2012 and 2011 were, in millions, $21.9 and $10.2, respectively.

(5) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

Our estimated proved oil and natural gas reserves decreased from approximately 26.3 million BOE at June 30, 2011 to approximately 19.1 million BOE at June 30, 2012, reflecting primarily the decrease in our proved undeveloped natural gas reserves from 101.4 Bcf at June 30, 2011 to 20.0 Bcf at June 30, 2012. The unweighted arithmetic average of the first-day-of-the-month natural gas prices was $3.146 per MMBtu for the period from July 2011 to June 2012 and $4.209 per MMBtu for the period from July 2010 to June 2011. These average prices were the natural gas prices used to estimate our natural gas reserves at June 30, 2012 and 2011, respectively. As a result of this decline in natural gas prices, at June 30, 2012, we removed 97.8 Bcf of previously classified proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana from our estimated total proved reserves, most of which were attributable to non-operated properties. As the leasehold acreage associated with these previously classified proved undeveloped natural gas reserves is held by production from existing Haynesville wells, however, these natural gas volumes remain available to be developed by us or the operator at a future time when natural gas prices improve, so long as the producing wells holding this acreage continue to produce as necessary to maintain held-by-production status.

Our estimated proved oil reserves increased almost eight-fold to approximately 6.7 million Bbl at June 30, 2012 from approximately 0.9 million Bbl at June 30, 2011. This increase is attributable to proved oil reserves added as a result of our drilling operations in the Eagle Ford shale in South Texas. The PV-10 of our proved oil and natural gas reserves more than doubled to $303.4 million at June 30, 2012 from $144.4 million at June 30, 2011. Our proved developed and proved undeveloped oil reserves increased to 3.1 million Bbl and 3.6 million Bbl, respectively, at June 30, 2012, compared to 401,000 Bbl and 478,000 Bbl, respectively, at June 30, 2011. Our estimated total proved oil and natural gas reserves at June 30, 2012 were approximately 64% proved developed reserves and were made up of approximately 35% oil and 65% natural gas. Our estimated total proved reserves at June 30, 2011 were approximately 34% proved developed reserves and were made up of approximately 3% oil and 97% natural gas.

During the six months ended June 30, 2012, natural gas prices have declined to their lowest levels in many years, with the NYMEX Henry Hub natural gas futures contract for the earliest delivery date ranging between a high of $3.10 per MMBtu in early January and a low of $1.91 in mid-April. If natural gas prices continue to remain at or near these levels or if natural gas prices decline further, the unweighted arithmetic average of the first-day-of-the month prices for the previous 12 months used to estimate natural gas reserves may also continue to decline in future periods. Should this occur, it may become necessary for us to remove the remaining Haynesville shale proved undeveloped reserves (approximately 14 Bcf) from our estimated total proved reserves in a future period. This could, in turn, result in additional impairment of the carrying value of our oil and natural gas properties on our balance sheet due to the full-cost ceiling limitation.

There have been no changes to the technology we used to establish reserves or to our internal control over the reserves estimation process from those set forth in our Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC.

Critical Accounting Policies

There have been no changes to our critical accounting policies and estimates from those set forth in the Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC.

The Company has elected not to take advantage of the extended transition period provided in Securities Act of 1933 Section 7(a)(2)(B) for complying with new or revised accounting standards.

Recent Accounting Pronouncements

There have been no additional recent accounting pronouncements impacting our financial reporting from those set forth in the Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC.

Results of Operations

Revenues

The following table summarizes our revenues and production data for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012 (Unaudited)	2011 (Unaudited)	2012 (Unaudited)	2011 (Unaudited)
Operating Data:				
Revenues (in thousands):				
Oil	$ 29,426	$ 5,110	$ 50,973	$ 6,790
Natural gas	6,652	15,754	14,269	27,772
Total oil and natural gas revenues	36,078	20,864	65,242	34,562
Realized gain on derivatives	4,713	952	7,776	2,802
Unrealized gain (loss) on derivatives	15,114	332	11,844	(1,336)
Total revenues	$ 55,905	$ 22,148	$ 84,862	$ 36,028
Net Production Volumes:				
Oil (MBbl)	285	51	485	70
Natural gas (Bcf)	3.1	4.1	6.2	7.4
Total oil equivalents (MBOE)[(1),(2)]	795	728	1,525	1,295
Average net daily production (BOE/d)[(2)]	8,738	8,004	8,380	7,157
Average Sales Prices:				
Oil, with realized derivatives (per Bbl)	$ 105.82	$ 99.72	$ 106.54	$ 96.86
Oil, without realized derivatives (per Bbl)	$ 103.29	$ 99.72	$ 105.06	$ 96.86
Natural gas, with realized derivatives (per Mcf)	$ 3.48	$ 4.11	$ 3.42	$ 4.16
Natural gas, without realized derivatives (per Mcf)	$ 2.17	$ 3.88	$ 2.29	$ 3.78

(1) Thousands of barrels of oil equivalent.
(2) Estimated using a conversion ratio of one Bbl per six Mcf.

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

Oil and natural gas revenues. Our oil and natural gas revenues increased by approximately $15.2 million to approximately $36.1 million, or an increase of about 73%, for the three months ended June 30, 2012 as compared to the three months ended June 30, 2011. This increase in oil and natural gas revenues reflects an increase in our oil revenues of $24.3 million and a decrease in our natural gas revenues of $9.1 million for the three months ended June 30, 2012 as compared to the comparable period in 2011. Our oil revenues increased almost six-fold to $29.4 million for the three months ended June 30, 2012 as compared to $5.1 million for the three months ended June 30, 2011. Our oil production also increased almost six-fold to approximately 285,000 Bbl of oil, or about 3,130 Bbl of oil per day, from approximately 51,000 Bbl of oil, or about 560 Bbl of oil per day, during the comparable periods due to our drilling operations in the Eagle Ford shale. A portion of this increase in oil revenue also reflects a somewhat higher weighted average oil price of $103.29 per Bbl realized during the three months ended June 30, 2012 as compared to a weighted average oil price of $99.72 per Bbl realized during the three months ended June 30, 2011. The decrease in our natural gas revenues reflects a decline in our natural gas production by about 25% to approximately 3.1 Bcf for the three months ended June 30, 2012 as compared to approximately 4.1 Bcf for the three months ended June 30, 2011. This decline in natural gas production is due to several factors, including (i) the natural decline in natural gas production primarily from our existing Cotton Valley and Haynesville shale wells in Northwest Louisiana and East Texas, coupled with our decision not to drill any operated Haynesville shale wells in 2012, (ii) the voluntary curtailment of natural gas production from some of our non-operated Haynesville shale wells in Northwest Louisiana and (iii) the flaring of a portion of the natural gas produced from our newly completed Eagle Ford shale wells in South Texas as a result of gas pipeline constraints and awaiting the installation of permanent production facilities. This decrease in natural gas revenues also results from a significantly lower weighted average natural gas price of $2.17 per Mcf realized during the three months ended June 30, 2012 as compared to a weighted average natural gas price of $3.88 per Mcf realized during the three months ended June 30, 2011.

Realized gain (loss) on derivatives. Our realized gain on derivatives increased by approximately $3.8 million to $4.7 million for the three months ended June 30, 2012 as compared to the three months ended June 30, 2011. For the three months ended June 30, 2012, we realized a gain of approximately $4.0 million on our natural gas derivative contracts, and we realized a gain of approximately $0.7 million on our oil derivative contracts. As a result of declining natural gas prices between the comparable periods, we realized an average gain of $2.22 per MMBtu hedged on all of our open natural gas costless collar contracts during the three months ended June 30, 2012 as compared to an average gain of $0.91 per MMBtu hedged on all of our open natural gas costless collar contracts during the three months ended June 30, 2011. Our total natural gas volumes hedged for the three months ended June 30, 2012 were also approximately 71% higher than the total natural gas volumes hedged for the same period in 2011. The realized gain from our open oil costless collar contracts resulted from a decline in oil prices during the three months ended June 30, 2012. We realized an average gain of $2.40 per Bbl hedged on all of our open oil costless collar contracts during the three months ended June 30, 2012. We had no open oil costless collar contracts during the three months ended June 30, 2011.

Unrealized gain (loss) on derivatives. Our unrealized gain on derivatives was approximately $15.1 million for the three months ended June 30, 2012 as compared to an unrealized gain on derivatives of $0.3 million for the three months ended June 30, 2011. During the period from March 31, 2012 to June 30, 2012, the net fair value of our open oil and natural gas costless collar contracts increased from approximately $6.0 million to approximately $21.1 million, resulting in an unrealized gain on derivatives of approximately $15.1 million for the three months ended June 30, 2012. During the three months ended June 30, 2012, the net fair value of our open oil costless collar contracts increased by approximately $20.5 million primarily due to a decline in oil prices during the second quarter of 2012. During the three months ended June 30, 2012, the net fair value of our open natural gas costless collar contracts decreased by approximately $5.4 million in large part due to the gains realized on these contracts during the second quarter of 2012. During the three months ended June 30, 2012, we also entered into additional natural gas costless collar contracts. During the period from March 31, 2011 to June 30, 2011, the net fair value of our open natural gas costless collar contracts increased from $2.5 million to $2.8 million, resulting in an unrealized gain on derivatives of $0.3 million for the three months ended June 30, 2011. We had no open oil costless collar contracts during the three months ended June 30, 2011.

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

Oil and natural gas revenues. Our oil and natural gas revenues increased by approximately $30.7 million to approximately $65.2 million, or an increase of about 89%, for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. This increase in oil and natural gas revenues reflects an increase in our oil revenues of $44.2 million and a decrease in our natural gas revenues of $13.5 million for the six months ended June 30, 2012 as compared to the comparable period in 2011. Our oil revenues increased almost eight-fold to $51.0 million for the six months ended June 30, 2012 as compared to $6.8 million for the six months ended June 30, 2011. Our oil production increased almost seven-fold to approximately 485,000 Bbl of oil, or about 2,670 Bbl of oil per day, from approximately 70,000 Bbl of oil, or about 390 Bbl of oil per day, during the comparable periods due to our drilling operations in the Eagle Ford shale. A portion of this increase in oil revenue also reflects a somewhat higher weighted average oil price of $105.06 per Bbl realized during the first six months of 2012 as compared to a weighted average oil price of $96.86 per Bbl realized during the first six months of 2011. The decrease in our natural gas revenues reflects a decline in our natural gas production by about 15% to approximately 6.2 Bcf for the six months ended June 30, 2012 as compared to approximately 7.4 Bcf for the six months ended June 30, 2011. This decline in natural gas production is due to several factors, including (i) the natural decline in natural gas production primarily from our existing Cotton Valley and Haynesville shale wells in Northwest Louisiana and East Texas, coupled with our decision not to drill any operated Haynesville shale wells in 2012, (ii) the voluntary curtailment of natural gas production from some of our non-operated Haynesville shale wells in Northwest Louisiana and (iii) the flaring of a portion of the natural gas produced from our newly completed Eagle Ford shale wells in South Texas as a result of gas pipeline constraints and awaiting the installation of permanent production facilities. This decrease in natural gas revenues also results from a significantly lower weighted average natural gas price of $2.29 per Mcf realized during the first six months of 2012 as compared to a weighted average natural gas price of $3.78 per Mcf realized during the first six months of 2011.

Realized gain (loss) on derivatives. Our realized gain on derivatives increased by approximately $5.0 million to $7.8 million for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. For the six months ended June 30, 2012, we realized a gain of approximately $7.1 million on our natural gas derivative contracts, and we realized a gain of approximately $0.7 million on our oil derivative contracts. As a result of declining natural gas prices between the comparable periods, we realized an average gain of approximately $1.96 per MMBtu hedged on all of our open natural gas costless collar contracts during the six months ended June 30, 2012 as compared to $1.14 per MMBtu hedged on all of our open natural gas costless collar contracts during the six months ended June 30, 2011. Our total natural gas volumes hedged for the six months ended June 30, 2012 were also approximately 46% higher than the total natural gas volumes hedged for the same period in 2011. The realized gain from our open oil costless collar contracts resulted from a decline in oil prices during the second quarter of 2012. We realized an average gain of $1.56 per Bbl hedged on all of our open oil costless collar contracts during the six months ended June 30, 2012. We had no open oil costless collar contracts during the six months ended June 30, 2011.

Unrealized gain (loss) on derivatives. Our unrealized gain on derivatives was approximately $11.8 million for the six months ended June 30, 2012 as compared to an unrealized loss of $1.3 million for the six months ended June 30, 2011. During the period from December 31, 2011 to June 30, 2012, the net fair value of our open oil and natural gas costless collar contracts increased from approximately $9.3 million to approximately $21.1 million, resulting in an unrealized gain on derivatives of approximately $11.8 million for the six months ended June 30, 2012. During the six months ended June 30, 2012, the net fair value of our open oil costless collar contracts increased by approximately $15.2 million primarily due to a decline in oil prices during the second quarter of

2012. During the six months ended June 30, 2012, the net fair value of our open natural gas costless collar contracts decreased by $3.4 million in part due to the gains realized on these contracts during the first six months of 2012 offset by lower natural gas prices which increased the net fair value of the remaining open contracts. During the first six months of 2012, we also entered into additional natural gas costless collar contracts. During the period from December 31, 2010 to June 30, 2011, the net fair value of our open natural gas costless collar contracts decreased from $4.1 million to $2.8 million, resulting in an unrealized loss on derivatives of $1.3 million for the six months ended June 30, 2011. We had no open oil costless collar contracts during the six months ended June 30, 2011.

Expenses

The following table summarizes our operating expenses and other income (expense) for the periods indicated. As a result of the increasing significance of our oil production, all per unit expenses are presented as per BOE as compared to per Mcfe in prior reporting periods.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)
(In thousands, except expenses per BOE)				
Expenses:				
Production taxes and marketing	$ 2,619	$ 1,654	$ 4,783	$ 2,954
Lease operating	6,375	1,969	11,020	3,574
Depletion, depreciation and amortization	19,913	8,179	31,119	15,290
Accretion of asset retirement obligations	58	57	111	96
Full-cost ceiling impairment	33,205	—	33,205	35,673
General and administrative	4,093	3,094	7,882	5,712
Total expenses	66,263	14,953	88,120	63,299
Operating (loss) income	(10,358)	7,195	(3,258)	(27,271)
Other income (expense):				
Net loss on asset sales and inventory impairment	(60)	—	(60)	—
Interest expense	(1)	(183)	(309)	(290)
Interest and other income	30	94	103	166
Total other expense	(31)	(89)	(266)	(124)
(Loss) income before income taxes	(10,389)	7,106	(3,524)	(27,395)
Total income tax benefit	(3,713)	(46)	(649)	(6,952)
Net (loss) income	$ (6,676)	$ 7,152	$ (2,875)	$ (20,443)
Expenses per BOE:				
Production taxes and marketing	$ 3.29	$ 2.27	$ 3.14	$ 2.28
Lease operating	$ 8.02	$ 2.70	$ 7.23	$ 2.76
Depletion, depreciation and amortization	$ 25.04	$ 11.23	$ 20.40	$ 11.80
General and administrative	$ 5.15	$ 4.25	$ 5.17	$ 4.41

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

Production taxes and marketing. Our production taxes and marketing expenses increased by approximately $1.0 million to approximately $2.6 million, or an increase of approximately 58%, for the three months ended June 30, 2012 as compared to the three months ended June 30, 2011. The increase in our production taxes and marketing expenses primarily reflects the increase in our total oil and natural gas revenues by 73% during the three months ended June 30, 2012 as compared to the three months ended June 30, 2011. The majority of this increase was attributable to production taxes and marketing expenses associated with the large increase in oil production resulting from our drilling operations in the Eagle Ford shale in South Texas. Our total production was comprised of approximately 36% oil and 64% natural gas for the three months ended June 30, 2012 as compared to approximately 7% oil and 93% natural gas during the same period in 2011. On a unit-of-production basis, our production taxes and marketing expenses increased by 45% to $3.29 per BOE for the three months ended June 30, 2012 as compared to $2.27 per BOE for the three months ended June 30, 2011.

Lease operating expenses. Our lease operating expenses increased by approximately $4.4 million to approximately $6.4 million, or an increase of approximately three-fold for the three months ended June 30, 2012 as compared to the three months ended June 30, 2011. Our total oil and natural gas production increased by about 9% from approximately 728,000 BOE during the three months ended June 30, 2011 to approximately 795,000 BOE during the three months ended June 30, 2012, but our oil production increased almost six-fold from approximately 51,000 Bbl to approximately 285,000 Bbl during these respective periods. The increase in lease operating expenses was primarily attributable to the large increase in our oil production as a result of our ongoing drilling and completion operations in the Eagle Ford shale in 2012. In addition, oil production comprised 36% of our total production during the three months ended June 30, 2012 as compared to only 7% of our total production during the same period in 2011, resulting in higher overall lease operating expenses during the second quarter of 2012. During the three months ended June 30, 2012, we completed and initiated oil and natural gas production from 6 gross/5.9 net wells in the Eagle Ford shale on properties where new production facilities were being installed or natural gas pipelines were awaiting construction. While these new facilities were being installed and tested, much of the oil and natural gas was produced through rental test equipment monitored by 24-hour contract personnel, resulting in higher operating costs from these properties during the three months ended June 30, 2012 than we anticipate going forward now that the permanent production facilities and natural gas pipeline connections on most of these properties are complete. As we continue to drill new properties in the Eagle Ford shale throughout the remainder of 2012, however, we also expect to produce new wells on these properties through rental test equipment until more permanent facilities can be constructed and installed. Our lease operating expenses per unit of production increased 197% to $8.02 per BOE for the three months ended June 30, 2012 as compared to $2.70 per MBOE for the three months ended June 30, 2011.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $11.7 million to $19.9 million, or an increase of about 143%, for the three months ended June 30, 2012 as compared to the three months ended June 30, 2011. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased to $25.04 per BOE for the three months ended June 30, 2012, or an increase of about 123%, from $11.23 per BOE for the three months ended June 30, 2011. This increase in our depletion, depreciation and amortization expenses was primarily attributable to the decrease in our total proved oil and natural gas reserves to 19.1 million BOE at June 30, 2012 as compared to 26.3 million BOE at June 30, 2011. This increase in depletion, depreciation and amortization expense was also partially due to the increase of approximately 9% in our total oil and natural gas production to approximately 795,000 BOE during the three months ended June 30, 2012 as compared to approximately 728,000 BOE during the three months ended June 30, 2011, as well as to the higher drilling and completions costs on a per BOE basis associated with oil reserves added in the Eagle Ford shale in South Texas as compared with our Haynesville shale natural gas assets in Northwest Louisiana.

Accretion of asset retirement obligations. Our accretion of asset retirement obligations expenses remained essentially unchanged at approximately $58,000 and $57,000 for the three months ended June 30, 2012 and 2011, respectively. This item is an insignificant component of our overall expenses.

Full-cost ceiling impairment. At June 30, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $21.3 million. As a result, we recorded an impairment charge of $33.2 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $11.9 million, which is reflected in our operating expenses for the three months ended June 30, 2012. This impairment was primarily attributable to the continued decline in natural gas prices, resulting in the removal of 97.8 Bcf of previously classified proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana from our total proved reserves at June 30, 2012, most of which were attributable to non-operated properties. No impairment to the net carrying value of our oil and natural gas properties on the balance sheet resulting from a full-cost ceiling impairment was recorded for the three months ended June 30, 2011.

General and administrative. Our general and administrative expenses increased by $1.0 million to $4.1 million, or an increase of about 32%, for the three months ended June 30, 2012 as compared to the three months ended June 30, 2011. Our general and administrative expenses increased by 21% on a unit-of-production basis to $5.15 per BOE for the three months ended June 30, 2012 as compared to $4.25 per BOE for the three months ended June 30, 2011. The increase in our general and administrative expenses was attributable primarily to increased compensation, accounting, legal and other administrative expenses, much of which is associated with becoming a public company in February 2012.

Net loss on asset sales and inventory impairment. During the three months ended June 30, 2012, we sold some of our lease and well equipment inventory for approximately $60,000 less than the previously recorded fair value and recognized this loss upon the sale. No such sale or impairment of lease and well equipment inventory occurred during the same period in 2011.

Interest expense. For the three months ended June 30, 2012, we incurred total interest expense of approximately $0.3 million. We capitalized all of the interest expense on the outstanding borrowings under our Credit Agreement to certain qualifying projects for the three months ended June 30, 2012. Approximately $1,000 in interest payments made to the State of Louisiana was expensed to operations. During the three months ended June 30, 2012, we borrowed $45.0 million under our Credit Agreement to finance a portion of our working capital requirements and capital expenditures. Our total outstanding borrowings at June 30, 2012 were $60.0 million, and the effective interest rate on these borrowings was approximately 3.3% per annum. At June 30, 2011, we had outstanding borrowings of $85.0 million under our Credit Agreement and incurred total interest expense of approximately $0.5 million. We capitalized $0.3 million of our interest expense on certain qualifying projects and expensed the remaining $0.2 million to operations for the three months ended June 30, 2011.

Interest and other income. Our interest and other income decreased by approximately $64,000 to approximately $30,000, or a decrease of about 68%, for the three months ended June 30, 2012 as compared to the three months ended June 30, 2011. The decrease in our interest and other income was due primarily to a decrease in the natural gas transportation income received from third parties during the three months ended June 30, 2012 as compared to the three months ended June 30, 2011. On the whole, this item is an insignificant component of our overall income. Our cash and cash equivalents and certificates of deposit decreased to approximately $9.7 million at June 30, 2012 from approximately $12.0 million at June 30, 2011.

Total income tax provision (benefit). We recorded a total income tax benefit of approximately $3.7 million for the three months ended June 30, 2012 as compared to a total income tax benefit of approximately $46,000 for the three months ended June 30, 2011. During the quarter ended June 30, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $21.3 million. We recorded an impairment charge of $33.2 million to the net capitalized costs of our oil and natural gas properties and a deferred tax credit of $11.9 million, which was partially offset primarily by an increase in the deferred tax liability related to our unrealized gain on derivatives, resulting in the income tax benefit recorded for the three months ended June 30, 2012. The income tax benefit recorded for the three months ended June 30, 2011 reflects a State of Louisiana income tax refund of approximately $46,000 received during the second quarter of 2011. We had a net loss for the three months ended June 30, 2012. The Company established a valuation allowance at March 31, 2011 and retained a valuation allowance of approximately $2.8 million at June 30, 2011, due to uncertainties regarding the future realization of its deferred tax assets. As a result, there was no income tax expense recorded for the three months ended June 30, 2011.

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

Production taxes and marketing. Our production taxes and marketing expenses increased by approximately $1.8 million to approximately $4.8 million, or an increase of approximately 62%, for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. The increase in our production taxes and marketing expenses primarily reflects the increase in our total oil and natural gas revenues of 89% during the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. The majority of this increase was attributable to production taxes and marketing expenses associated with the large increase in oil production resulting from our drilling operations in the Eagle Ford shale in South Texas. Our total production was comprised of approximately 32% oil and 68% natural gas for the six months ended June 30, 2012 as compared to approximately 5% oil and 95% natural gas during the same period in 2011. On a unit-of-production basis, our production taxes and marketing expenses increased by 38% to $3.14 per BOE for the six months ended June 30, 2012 as compared to $2.28 per BOE for the six months ended June 30, 2011.

Lease operating expenses. Our lease operating expenses increased by approximately $7.4 million to approximately $11.0 million, or an increase of approximately three-fold for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. Our total oil and natural gas production increased 18% from approximately 1.3 million BOE to approximately 1.5 million BOE, but our oil production increased almost seven-fold from approximately 70,000 Bbl to approximately 485,000 Bbl during these respective periods. The increase in lease operating expenses was primarily attributable to the large increase in our oil production as a result of our ongoing drilling and completion operations in the Eagle Ford shale in 2012. In addition, oil production comprised 32% of our total production during the six months ended June 30, 2012 as compared to only 5% of our total production during the same period in 2011, resulting in higher overall lease operating expenses during the first six months of 2012. During the six months ended June 30, 2012, we completed and initiated oil and natural gas production from 12 gross/11.8 net operated Eagle Ford wells on properties where new production facilities or natural gas pipelines were awaiting construction. While these new facilities were being installed and tested, much of the oil and natural gas was produced through rental test equipment monitored by 24-hour contract personnel, resulting in higher operating costs from these properties during the six months ended June 30, 2012 than we anticipate going forward now that the permanent production facilities and natural gas pipeline connections on most of these properties are complete. As we continue to drill new properties in the Eagle Ford shale throughout the remainder of 2012, however, we also expect to produce new wells on these properties through rental test equipment until more permanent facilities can be constructed and installed. Our lease operating expenses per unit of production increased 162% to $7.23 per BOE for the six months ended June 30, 2012 as compared to $2.76 per BOE for the six months ended June 30, 2011.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $15.8 million to $31.1 million, or an increase of about 104%, for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased to $20.40 per BOE for the six months ended June 30, 2012, or an increase of about 73%, from $11.80 per BOE for the six months ended June 30, 2011. This increase in our depletion, depreciation and amortization expenses was primarily attributable to the decrease in our total proved oil and natural gas reserves to 19.1 million BOE at June 30, 2012 as compared to 26.3 million BOE at June 30, 2011. This increase in our depletion, depreciation and amortization expenses was also partially attributable to an increase of approximately 18% in our total oil and natural gas production to approximately 1.5 million BOE during the six months ended June 30, 2012 as compared to approximately 1.3 million BOE during the six months ended June 30, 2011, as well as to the higher drilling and completions costs on a per BOE basis associated with oil reserves added in the Eagle Ford shale in South Texas as compared with our Haynesville shale natural gas assets in Northwest Louisiana.

Accretion of asset retirement obligations. Our accretion of asset retirement obligations expenses increased by approximately $15,000 to approximately $111,000, or an increase of about 16%, for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. The increase in our accretion of asset retirement obligations was due primarily to the addition of new wells through our drilling of operated wells and our participation in the drilling of non-operated wells, although, on the whole, this item is an insignificant component of our overall expenses.

Full-cost ceiling impairment. At June 30, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $21.3 million. As a result, we recorded an impairment charge of $33.2 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $11.9 million, which is reflected in our operating expenses for the six months ended June 30, 2012. This impairment was primarily attributable to the continued decline in natural gas prices, resulting in the removal of 97.8 Bcf of previously classified proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana from our total proved reserves at June 30, 2012, most of which were attributable to non-operated properties. During the first quarter of 2011, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $23.0 million. As a result, we recorded an impairment charge of $35.7 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $12.7 million, which is reflected in our operating expenses for the six months ended June 30, 2011.

General and administrative. Our general and administrative expenses increased by $2.2 million to $7.9 million, or an increase of about 38%, for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. Our general and administrative expenses increased by 17% on a unit-of-production basis to $5.17 per BOE for the six months ended June 30, 2012 as compared to $4.41 per BOE for the six months ended June 30, 2011. The increase in our general and administrative expenses was attributable primarily to increased compensation, accounting, legal and other administrative expenses, much of which is associated with becoming a public company in February 2012.

Net loss on asset sales and inventory impairment. During the six months ended June 30, 2012, we sold some of our lease and well equipment inventory for approximately $60,000 less than the previously recorded fair value and recognized this loss upon the sale. No such sale or impairment of lease and well equipment inventory occurred during the same period in 2011.

Interest expense. For the six months ended June 30, 2012, we incurred total interest expense of approximately $0.9 million. We capitalized approximately $0.6 million of our interest expense on certain qualifying projects for the six months ended June 30, 2012 and expensed the remaining $0.3 million to operations. On February 8, 2012, we repaid our borrowings then outstanding of $123.0 million under our Credit Agreement using a portion of the net proceeds received from our Initial Public Offering. From March 1 through June 30, 2012, we borrowed $60.0 million under our Credit Agreement to finance a portion of our working capital requirements and capital expenditures. Our total outstanding borrowings at June 30, 2012 were $60.0 million, and the effective interest rate on these borrowings was approximately 3.3% per annum. At June 30, 2011, we had borrowings of $85.0 million under our Credit Agreement and we incurred total interest expense of approximately $0.6 million. We capitalized $0.3 million of our interest expense on certain qualifying projects and expensed the remaining $0.3 million to operations for the six months ended June 30, 2011.

Interest and other income. Our interest and other income decreased by approximately $63,000 to approximately $103,000, or a decrease of about 38%, for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. The decrease in our interest and other income was due primarily to a decrease in the natural gas transportation income received from third parties during the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. On the whole, this item is an insignificant component of our overall income. Our cash and cash equivalents and certificates of deposit decreased to approximately $9.7 million at June 30, 2012 from approximately $12.0 million at June 30, 2011.

Total income tax provision (benefit). We recorded a total income tax benefit of approximately $0.6 million for the six months ended June 30, 2012 as compared to a total income tax benefit of approximately $7.0 million for the six months ended June 30, 2011. During the six months ended June 30, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $21.3 million. We recorded an impairment charge of $33.2 million to the net capitalized costs of our oil and natural gas properties and a deferred tax credit of $11.9 million, which was partially offset primarily by an increase in the deferred tax liability related to our unrealized gain on derivatives, resulting in the income tax benefit recorded for the six months ended June 30, 2012. During the six months ended June 30, 2011, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $23.0 million. As a result, we recorded an impairment charge of $35.7 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $12.7 million. We had a net loss in each period for the six months ended June 30, 2012 and 2011.

Liquidity and Capital Resources

Prior to the consummation of our Initial Public Offering on February 7, 2012, our primary sources of liquidity were capital contributions from private investors, our cash flows from operations, borrowings under our Credit Agreement and the proceeds from a significant sale of a portion of our assets in 2008. Our primary use of capital has been, and will continue to be during 2012 and for the foreseeable future, for the acquisition, exploration and development of oil and natural gas properties. We continually evaluate potential capital sources, including equity and debt financings, additional borrowings and joint venture partners on some of our properties, in order to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital.

At June 30, 2012, we had cash and cash equivalents and certificates of deposits totaling approximately $9.7 million, the borrowing base under our Credit Agreement was $125.0 million and we had $60.0 million of outstanding long-term borrowings and approximately $1.3 million in outstanding letters of credit. These borrowings bore interest at an effective rate of approximately 3.3% per annum. In July and August 2012, we borrowed an additional $30.0 million under our Credit Agreement to finance a portion of our working capital requirements and capital expenditures. At August 14, 2012, we had $90.0 million of outstanding long-term borrowings and approximately $1.3 million in outstanding letters of credit.

While we believe our cash and cash equivalents, together with our anticipated cash flows and future potential borrowings under our Credit Agreement, will be adequate to fund our capital expenditure requirements and any acquisitions of interests and acreage for 2012, funding for future acquisitions of interests and acreage or our future capital expenditure requirements for 2013 and subsequent years may require additional sources of financing, which may not be available. On February 28, 2012, our borrowing base was increased to $125.0 million pursuant to a borrowing base redetermination made by the lenders at our request. At August 14, 2012, we are seeking an amended and restated credit facility that may increase our borrowing capacity to up to $200.0 million. As a result primarily of our anticipated increases in oil production and proved oil reserves, we expect to have a sufficient increase in our cash flows from operations during the year ending December 31, 2012 as compared to our cash flows from operations in prior periods, as well as a significant increase in the borrowing base under our Credit Agreement or under an amended and restated credit facility to help fund our 2012 capital expenditure budget.

A majority of our anticipated increase in cash flows during the year ending December 31, 2012 is expected to come from our exploration activities on unproved properties at December 31, 2011 in the Eagle Ford shale play assuming such exploration activities are successful. If our exploration activities result in less cash flows than anticipated, we may seek additional sources of capital, including through borrowings under our Credit Agreement or pursuant to an amended and restated credit facility (assuming availability under our borrowing base). In addition to future borrowings under our Credit Agreement or an amended and restated credit facility, we may also seek to raise additional funds by selling shares of our common stock or securities convertible or exercisable into our common stock (including debt securities or other preferential securities) in the public market or otherwise or seek joint venture partners on some of our properties. It is likely that any such sales of securities would dilute the ownership interest of our existing shareholders. It is also possible that, to the extent we are not able to obtain additional sources of liquidity, we may modify our planned capital expenditures budget for 2012 accordingly. Exploration activities are subject to a number of risks and uncertainties that could impact our ability to sufficiently increase our reserves, cash flows from operations and borrowing base under our Credit Agreement or any amended and restated credit facility.

Our cash flows for the six months ended June 30, 2012 and 2011 are presented below:

	Six Months Ended June 30,	
	2012	2011
(In thousands)	**(Unaudited)**	**(Unaudited)**
Net cash provided by operating activities	$ 51,526	$ 19,531
Net cash used in investing activities	(136,877)	(91,089)
Net cash provided by financing activities	84,499	60,422
Net change in cash and cash equivalents	(852)	(11,136)
Adjusted EBITDA(1)	$ 49,264	$ 25,472

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see “Non-GAAP Financial Measures” below.

Cash Flows Provided by Operating Activities

Net cash provided by operating activities increased by approximately $32.0 million to $51.5 million for the six months ended June 30, 2012 as compared to net cash provided by operating activities of $19.5 million for the six months ended June 30, 2011. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased significantly to $48.9 million for the six months ended June 30, 2012 from $25.2 million for the six months ended June 30, 2011. This increase is primarily attributable to the almost seven-fold increase in our oil production to approximately 485 MBbl from approximately 70 MBbl during the respective periods. A portion of the increase in net cash provided by operating activities also reflects the higher average oil price of $105.06 per Bbl realized during the six months ended June 30, 2012 as compared to an average oil price of $96.86 per Bbl realized during the six months ended June 30, 2011. Our accounts payable and accrued liabilities increased to approximately $53.1 million at June 30, 2012 from approximately $10.6 million at June 30, 2011 due to our increased operating activity in South Texas. Our accounts receivable increased to approximately $15.9 million at June 30, 2012 from approximately $15.2 million at June 30, 2011, primarily due to our increased operating activity in South Texas.

Our operating cash flows are sensitive to a number of variables, including changes in our production and volatility of oil and natural gas prices between reporting periods. Regional and worldwide economic activity, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of oil and natural gas. These factors are beyond our control and are difficult to predict.

Cash Flows Used in Investing Activities

Net cash used in investing activities increased by approximately $45.8 million to $136.9 million for the six months ended June 30, 2012 from $91.1 million for the six months ended June 30, 2011. This increase in net cash used in investing activities is almost entirely attributable to the increase in our oil and natural gas properties capital expenditures for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. Our oil and natural gas properties capital expenditures for the six months ended June 30, 2012 were primarily due to our operated drilling and completion activities in the Eagle Ford shale play in South Texas.

Expenditures for the acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipated investing $313.0 million in capital for acquisition, exploration and development activities in 2012 as follows:

	Amount (in millions)
Exploration and development drilling and associated infrastructure	$ 284.5
Leasehold acquisition	24.0
Other capital expenditures, 2-D and 3-D seismic data and recompletions of existing wells	4.5
Total	$ 313.0

At June 30, 2012, we have incurred approximately $146.7 million or about 47% of our 2012 estimated capital expenditures of $313.0 million. This includes approximately $12.3 million incurred to acquire additional leasehold acreage primarily in the Eagle Ford shale near our existing properties. During the first half of 2012, our drilling and completion costs for new wells have been less than we budgeted, although our costs for production facilities, pipelines and other infrastructure have exceeded our initial estimates. Overall, at June 30, 2012, we are executing our 2012 capital expenditure program largely as planned and remain within our anticipated capital expenditure budget for 2012. While we have budgeted $313.0 million for 2012, the aggregate amount of capital we will expend may fluctuate materially based on market conditions and our drilling results, as well as other opportunities we may encounter during the remainder of 2012.

For further information regarding our anticipated capital expenditure budget in 2012, see “Business – General” in our Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC. Our 2012 capital expenditures may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil or natural gas prices decline or costs increase significantly, we could defer a significant portion of our anticipated capital expenditures until later periods to conserve cash or to focus on projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling, completion and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in our exploration and drilling activities, contractual obligations and other factors both within and outside our control.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities was $84.5 million for the six months ended June 30, 2012 as compared to net cash provided by financing activities of $60.4 million for the six months ended June 30, 2011. The net cash provided by financing activities for the six months ended June 30, 2012 was principally due to the total proceeds from the Initial Public Offering of $146.5 million and total incremental borrowings of $70.0 million during the period, offset by the costs of the offering of $11.6 million incurred during the period and by the repayment of $123.0 million in borrowings during the period. We also received approximately $2.7 million from the exercise of stock options during the six months ended June 30, 2012. The net cash provided by financing activities for the six months ended June 30, 2011 was primarily attributable to $60.0 million in borrowings under the Credit Agreement and $0.6 million received from the issuance of common stock.

Non-GAAP Financial Measures

We define Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, including stock option and grant expense and restricted stock and restricted stock units expense, and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net income or cash flows as determined by GAAP. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies.

Management believes Adjusted EBITDA is necessary because it allows us to evaluate our operating performance and compare the results of operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in calculating Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which certain assets were acquired.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components of understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. The following table presents our calculation of Adjusted EBITDA and the reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

	Six Months Ended June 30,	
(In thousands)	**2012**	**2011**
Unaudited Adjusted EBITDA reconciliation to Net Loss:		
Net loss	$ (2,875)	$(20,443)
Interest expense	309	290
Total income tax benefit	(649)	(6,952)
Depletion, depreciation and amortization	31,119	15,291
Accretion of asset retirement obligations	111	96
Full-cost ceiling impairment	33,205	35,673
Unrealized (gain) loss on derivatives	(11,844)	1,336
Stock option and grant expense	(333)	159
Restricted stock and restricted stock units expense	161	22
Net loss on asset sales and inventory impairment	60	—
Adjusted EBITDA	$ 49,264	$ 25,472

(In thousands)	Six Months Ended June 30, 2012	2011
Unaudited Adjusted EBITDA reconciliation to Net Cash provided by Operating Activities:		
Net cash provided by operating activities	$51,526	$19,531
Net change in operating assets and liabilities	(2,571)	5,697
Interest expense	309	290
Current income tax (benefit) provision	—	(46)
Adjusted EBITDA	$49,264	$25,472

Our Adjusted EBITDA increased by approximately $23.8 million to approximately $49.3 million, or an increase of approximately 93%, for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. This increase in our Adjusted EBITDA is primarily attributable to the increase in our oil production and the associated increase in our oil and natural gas revenues for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. Our Adjusted EBITDA of $49.3 million for the first six months of 2012 was 99% of our Adjusted EBITDA of $49.9 million reported for all of 2011.

Credit Agreement

In December 2011, we amended and restated our senior secured revolving Credit Agreement for which Comerica Bank serves as administrative agent. Among other things, this amendment increased the size of the facility and extended the term until December 2016. MRC Energy Company is the borrower under the amended Credit Agreement. Borrowings are secured by mortgages on substantially all of our oil and natural gas properties and by the equity interests of all of MRC Energy Company's wholly owned subsidiaries, which are also guarantors. In addition, all obligations under the Credit Agreement are guaranteed by Matador Resources Company, the parent corporation. Various commodity hedging agreements with one of the lenders under the Credit Agreement (or an affiliate thereof) are also secured by the collateral and guaranteed by the subsidiaries of MRC Energy Company.

The amount of the borrowings under our Credit Agreement is limited to the lesser of $400.0 million or the borrowing base, which is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of our proved oil and natural gas reserves, but also on external factors, such as the lenders' lending policies and the lenders' estimates of future oil and natural gas prices, over which we have no control. At December 31, 2011, the borrowing base was $125.0 million and we had $113.0 million in outstanding borrowings under the Credit Agreement. In January 2012, we borrowed an additional $10.0 million to finance a portion of our working capital requirements, bringing the then outstanding indebtedness under the Credit Agreement to $123.0 million. Following the completion of our Initial Public Offering, we used a portion of the net proceeds to repay the then outstanding $123.0 million under our Credit Agreement in February 2012, at which time the borrowing base was reduced to $100.0 million. On February 28, 2012, the borrowing base was increased to $125.0 million pursuant to a special borrowing base redetermination made at our request. This borrowing base increase was determined by our lenders based upon, among other items, the increase in our proved oil and natural gas reserves at December 31, 2011.

Between March 1, 2012 and June 30, 2012, we borrowed $60.0 million under the Credit Agreement to finance a portion of our working capital requirements and capital expenditures. At June 30, 2012, we had $60.0 million in borrowings outstanding under the Credit Agreement, approximately $1.3 million in outstanding letters of credit issued pursuant to the Credit Agreement and approximately $63.7 million available for additional borrowings. At June 30, 2012, our outstanding borrowings bore interest at an effective rate of approximately 3.3% per annum.

We expect to access future borrowings under our Credit Agreement to fund a portion of our 2012 capital expenditure requirements in excess of amounts available from our cash flows. At August 14, 2012, we are seeking an amended and restated credit facility that may increase our borrowing capacity to up to $200.0 million. Unless we enter into an amended and restated credit facility during the second half of 2012, we also intend to seek additional redeterminations of our borrowing base as a result of, among other items, any increases to our proved oil and natural gas reserves as a result of our ongoing drilling operations in the Eagle Ford shale. In July and August 2012, we borrowed an additional $30.0 million under the Credit Agreement to finance a portion of our working capital requirements and capital expenditures. At August 14, 2012, we had $90.0 million in borrowings outstanding under the Credit Agreement, approximately $1.3 million in outstanding letters of credit issued pursuant to the Credit Agreement and approximately $33.7 million available for additional borrowings.

Both we and the lenders may each request an unscheduled redetermination of the borrowing base twice at any time during the first year of the Credit Agreement and once between scheduled redetermination dates thereafter. As noted above, we requested one such unscheduled redetermination in February 2012. In the event of a borrowing base increase, we are required to pay a fee to the lenders equal to a percentage of the amount of the increase, which will be determined based on market conditions at the time of the borrowing base increase. If the borrowing base were to be less than the outstanding borrowings under the Credit Agreement at any time, we would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or to repay the deficit in equal installments over a period of six months.

If we borrow funds as a base rate loan, such borrowings will bear interest at a rate equal to the higher of (i) the weighted average of rates used in overnight federal funds transactions with members of the Federal Reserve System plus 1.0% or (ii) the prime rate for Comerica Bank then in effect or (iii) a daily adjusted LIBOR rate plus 1.0% plus, in each case, an amount from 0.375% to 1.75% of such outstanding loan depending on the level of borrowings under the agreement. If we borrow funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (i) the quotient obtained by dividing (A) the interest rate appearing on Page BBAM of the Bloomberg Financial Markets Information Service by (B) a percentage equal to 100% minus the maximum rate during such interest calculation period at which Comerica Bank is required to maintain reserves on Eurocurrency Liabilities (as defined in Regulation D of the Board of Governors of the Federal Reserve System) plus (ii) an amount from 1.375% to 2.75% of such outstanding loan depending on the level of borrowings under the agreement. The interest period for Eurodollar borrowings may be one, two, three or six months as designated by us. A facility fee of 0.375% to 0.50%, depending on the amounts borrowed, is also paid quarterly in arrears. We include the facility fee and any loan amortization costs in our interest rate calculations and related disclosures.

Key financial covenants under the Credit Agreement require us to maintain (1) a current ratio, which is defined as consolidated total current assets plus the unused availability under the Credit Agreement divided by the consolidated total current liabilities, of 1.0 or greater for all reporting periods beginning March 31, 2012, and (2) a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.0 or less.

Subject to certain exceptions, our Credit Agreement contains various covenants that limit our, along with our subsidiaries', ability to take certain actions, including, but not limited to, the following:

- incur indebtedness or grant liens on any of our assets;
- enter into commodity hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates; and
- engage in certain asset dispositions, including a sale of all or substantially all of our assets.

If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of the borrowings and exercise other rights and remedies. Events of default include, but are not limited to, the following events:

- failure to pay any principal or interest on the notes or any reimbursement obligation under any letter of credit when due or any fees or other amount within certain grace periods;
- failure to perform or otherwise comply with the covenants and obligations in the Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;
- bankruptcy or insolvency events involving us or our subsidiaries; and
- a change of control, as defined in the credit agreement.

At June 30, 2012, we believe that we were in compliance with the terms of our Credit Agreement.

Off-Balance Sheet Arrangements

At June 30, 2012, we did not have any off-balance sheet arrangements.

Obligations and Commitments

We had the following material contractual obligations and commitments at June 30, 2012:

(in thousands)	Total	Less Than 1 Year	1 -3 Years	3 -5 Years	More Than 5 Years
	Payments Due by Period				
Contractual Obligations:					
Revolving credit borrowings, including letters of credit (1)	$61,300	$ 1,300	$ —	$60,000	$ —
Office lease	6,242	574	1,150	1,207	3,311
Non-operated drilling commitments (2)	2,822	2,822	—	—	—
Drilling rig contracts (3)	6,727	6,727	—	—	—
Asset retirement obligations	4,706	343	574	467	3,322
Total contractual cash obligations	$81,797	$11,766	$1,724	$61,674	$6,633

(1) At June 30, 2012, we had $60.0 million in revolving borrowings outstanding under our Credit Agreement and approximately $1.3 million in outstanding letters of credit issued pursuant to the Credit Agreement. The revolving borrowings are scheduled to mature in December 2016. These amounts do not include estimated interest on the obligations, because our revolving borrowings have short-term interest periods, and we are unable to determine what our borrowing costs may be in future periods.

(2) At June 30, 2012, we had outstanding commitments to participate in the drilling and completion of various non-operated wells, primarily in the Haynesville shale. Our working interests in these wells are small, and most of these wells were in progress at June 30, 2012. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of approximately $2.8 million at June 30, 2012, which we expect to incur within the next 12 months.

(3) During the first quarter of 2012, we extended one of our drilling rig contracts in South Texas for an additional nine months. We terminated a second drilling contract with no termination penalty and entered into a new contract for a higher performance rig with the same drilling rig contractor for a period of one year. Drilling operations under these two contracts began in March 2012. Should we elect to terminate one or both contracts and if the drilling contractor were unable to secure work for one or both rigs or if the drilling contractor were unable to secure work for one or both rigs at the same daily rates being charged to us prior to the end of their respective contract terms, we would incur termination obligations. Our maximum outstanding aggregate termination obligations under these contracts were approximately $6.7 million at June 30, 2012.

General Outlook and Trends

For the six months ended June 30, 2012, oil prices ranged from a high of approximately $109.77 per Bbl in late February to a low of approximately $77.69 per Bbl in late June, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. Oil prices remained near or above $100 per Bbl for much the first four months of 2012, but began declining in early May and ranged between $78 per Bbl and $85 per Bbl in June. We realized a weighted average oil price of $105.06 per Bbl ($106.54 per Bbl including realized gains from oil derivatives) for our oil production for the six months ended June 30, 2012 as compared to $96.86 per Bbl for the six months ended June 30, 2011. At August 10, 2012, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date closed at $92.87 per Bbl as compared to $82.89 per Bbl at August 10, 2011.

For the six months ended June 30, 2012, natural gas prices ranged from a high of approximately $3.10 per MMBtu in early January to a low of approximately $1.91 per MMBtu in mid-April, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. Natural gas prices declined during most of the first three to four months of 2012, reaching their lowest levels in many years, before rallying to $2.82 per MMBtu in late June. We realized a weighted average natural gas price of $2.29 per Mcf ($3.42 per Mcf including realized gains from natural gas derivatives) for our natural gas production for the six months ended June 30, 2012 as compared to $3.78 per Mcf ($4.16 per Mcf including realized gains from natural gas derivatives) for the six months ended June 30, 2011. At August 10, 2012, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date closed at $2.77 per MMBtu as compared to $4.00 per MMBtu at August 10, 2011.

The prices we receive for oil and natural gas heavily influence our revenue, profitability, cash flow available for capital expenditures, access to capital and future rate of growth. Oil and natural gas are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile and these markets will likely continue to be volatile in the future. Declines in oil or natural gas prices not only reduce our revenue, but could also reduce the amount of oil and natural gas we can produce economically. From time to time, we use derivative financial instruments to mitigate our exposure to commodity price risk associated with oil and natural gas prices. Even so, decisions as to whether and what production volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil and natural gas prices, and we may not always employ the optimal hedging strategy. Should oil or natural gas prices decrease to economically unattractive levels and remain there for an extended period of time, we may elect to delay some of our exploration and development plans for our prospects, or to cease exploration or development activities on certain prospects due to the anticipated unfavorable economics from such activities, each of which would have an adverse effect on our business, financial condition, results of operations and reserves. This, in turn, may affect the liquidity that can be accessed through the borrowing base under our Credit Agreement or through any amended and restated credit facility and through the capital markets.

Like other oil and natural gas producing companies, our properties are subject to natural production declines. By their nature, our wells in the Eagle Ford shale and the Haynesville shale experience rapid initial production declines. We attempt to overcome these production declines by drilling to develop and identify additional reserves, by exploring for new sources of reserves and, at times, by acquisitions. During times of severe oil and natural gas price declines, however, we may find it necessary to reduce capital expenditures and curtail drilling operations in order to preserve liquidity. A material reduction in capital expenditures and drilling activities could materially impact our production volumes, revenues, reserves and cash flows.

We must focus our efforts on increasing oil and gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our ability to find and develop sufficient quantities of oil and natural gas reserves at economical costs is critical to our long-term success. Future finding and development costs are subject to changes in the costs of acquiring, drilling and completing our prospects.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Except as set forth below, there have been no changes to our market risk since December 31, 2011 as set forth in the Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC.

Commodity price exposure. We are exposed to market risk as the prices of oil and natural gas fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative financial instruments in the past and expect to enter into derivative financial instruments in the future to cover a significant portion of our future production.

We use costless (or zero-cost) collars to manage risks related to changes in oil and natural gas prices. A costless collar provides us with downside price protection through the purchase of a put option which is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, this arrangement is initially “costless” to us.

We record all derivative financial instruments at fair value. The fair value of our derivative financial instruments is determined using purchase and sale information available for similarly traded securities. Comerica Bank is the single counterparty for all of our derivative instruments. We have evaluated the credit standing of Comerica Bank in determining the fair value of our derivative financial instruments.

We have entered into various costless collar transactions to mitigate our exposure to fluctuations in oil prices on a portion of our future expected oil production, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss to us pursuant to any of these transactions is the arithmetic average of the settlement prices for the NYMEX West Texas Intermediate oil futures contract for the first nearby month corresponding to the calculation period’s calendar month. When the settlement price is below the price floor established by these collars, we receive from Comerica Bank, as counterparty, an amount equal to the difference between the settlement price and the price floor multiplied by the contract oil volume. When the settlement price is above the price ceiling established by these collars, we pay Comerica Bank, as counterparty, an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract oil volume.

We have also entered into various costless collar transactions to mitigate our exposure to fluctuations in natural gas prices on a portion of our future expected natural gas production, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss to us pursuant to any of these transactions is the settlement price for the NYMEX Henry Hub natural gas futures contract for the delivery month corresponding to the calculation period’s calendar month for the last day of that contract period. When the settlement price is below the price floor established by these collars, we receive from Comerica Bank, as counterparty, an amount equal to the difference between the settlement price and the price floor multiplied by the contract natural gas volume. When the settlement price is above the price ceiling established by these collars, we pay to Comerica, as counterparty, an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract natural gas volume.

At June 30, 2012, we had multiple costless collar contracts open and in place to mitigate our exposure to oil and natural gas price volatility, each with a specified term (calculation period), notional quantity (volume hedged) and price floor and ceiling.

The following table is a summary of the fair value of our open oil costless collar contracts at June 30, 2012.

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (thousands)
Oil	07/01/2012 - 12/31/2012	20,000	90.00	104.20	$ 784
Oil	07/01/2012 - 12/31/2012	10,000	90.00	108.00	407
Oil	07/01/2012 - 12/31/2012	10,000	90.00	109.50	411
Oil	07/01/2012 - 12/31/2012	20,000	90.00	111.00	829
Oil	07/01/2012 - 12/31/2012	20,000	90.00	111.90	832
Oil	07/01/2012 - 12/31/2012	20,000	95.00	116.00	1,274
Oil	07/01/2012 - 03/31/2013	20,000	90.00	110.00	1,294
Oil	01/01/2013 - 12/31/2013	20,000	85.00	102.25	938
Oil	01/01/2013 - 12/31/2013	20,000	90.00	115.00	2,065
Oil	01/01/2013 - 12/31/2013	20,000	85.00	110.40	1,356
Oil	01/01/2013 - 12/31/2013	20,000	85.00	108.80	1,292
Oil	01/01/2013 - 06/30/2014	8,000	90.00	114.00	1,258
Oil	01/01/2013 - 06/30/2014	12,000	90.00	115.50	1,930
Total Oil					$ 14,670

All of our existing oil derivative contracts will expire at varying times during 2012, 2013 and 2014.

The following is a summary of the fair value of our open natural gas costless collar contracts at June 30, 2012.

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas	07/01/12 - 12/31/2012	300,000	4.50	5.60	$ 2,801
Natural Gas	07/01/12 - 12/31/2012	150,000	4.25	6.17	1,187
Natural Gas	07/01/12 - 12/31/2012	70,000	2.50	3.34	(26)
Natural Gas	07/01/12 - 07/31/2013	150,000	4.50	5.75	2,557
Natural Gas	07/01/12 - 07/31/2013	100,000	3.00	3.83	(63)
Total Natural Gas					$ 6,456

All of our existing natural gas derivative contracts will expire at varying times during 2012 and 2013.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Prior to the completion of our Initial Public Offering, we maintained limited accounting personnel to perform our accounting processes and limited supervisory resources with which to address our internal control over financial reporting. In connection with our audit for the year ended December 31, 2011, our independent registered public accountants identified and communicated a material weakness related to accounting for stock compensation expense. A material weakness is a control deficiency, or a combination of control deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual and interim financial statements will not be prevented or detected and corrected on a timely basis.

We became a public company on February 1, 2012 in connection with the completion of our Initial Public Offering. Prior to that date, we were a private company and were not required to file or submit reports under the Securities Exchange Act of 1934, as amended (the “Exchange Act”) and maintained disclosure controls and procedures in accordance with being a private company. As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e)) under the Exchange Act was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon this evaluation, as of the end of the period covered by this report, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were not effective due to the material weakness described above relating to our internal control over financial reporting.

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Changes in Internal Control over Financial Reporting

We have in the past engaged and currently engage outside consultants to review significant or complex accounting issues and calculations. During the quarter ended June 30, 2012, there we no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting except that we hired additional accounting personnel. During the quarter ended June 30, 2012, we hired an outside consulting company, Protiviti, Inc., to assist us with our internal audit function, including the evaluation and improvement of our internal control over financial reporting, and we formed a disclosure committee.

Part II—Other Information

Item 1. Legal Proceedings

See Part I, Item 1 – "Financial Statements," "Note 10 – Commitments and Contingencies" of this Quarterly Report on Form 10-Q which is incorporated by reference into this Part II, Item 1 – "Legal Proceedings."

Item 1A. Risk Factors

There have been no material changes to the risk factors discussed in our Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

On August 10, 2012, the Company borrowed $15.0 million under the Credit Agreement to finance a portion of its working capital requirements and capital expenditures. At August 14, 2012, the Company had $90.0 million in borrowings outstanding under the Credit Agreement, approximately $1.3 million in outstanding letters of credit issued pursuant to the Credit Agreement and approximately $33.7 million available for additional borrowings.

On August 10, 2012, the Company and Wade I. Massad entered into a Separation Agreement and Release (the "Separation Agreement") and a Consulting Agreement (the "Consulting Agreement"). Mr. Massad resigned from his position as Executive Vice President – Capital Markets effective July 31, 2012 but, by the terms of the Consulting Agreement, will continue to serve as a consultant to the Company and as a special advisor to the Company's Board of Directors as he did during portions of 2010 and 2011 prior to becoming a full-time employee of the Company in December 2011 in the run-up to the Company's initial public offering. By the terms of the Separation Agreement, Mr. Massad will receive a $60,000 bonus payment. Under the Consulting Agreement, Mr. Massad will also receive $7,500 per month for each month that he provides the Company with consulting services. The Separation Agreement and the Consulting Agreement are filed herewith as Exhibits 10.9 and 10.10.

Item 6. Exhibits

Exhibit Number	Description of Exhibits
10.1	Form of Nonqualified Stock Option Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.2	Form of Restricted Stock Unit Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.39 to the Annual Report on Form 10-K for the year ended December 31, 2011).
10.3	Form of Restricted Stock Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).

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Exhibit Number	Description of Exhibits
10.4	Form of Performance Restricted Stock and Restricted Stock Unit Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.5	Form of Nonqualified Stock Option Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.6	Form of Restricted Stock Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.7	Form of Performance Restricted Stock and Restricted Stock Unit Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.8	First Amendment to the Matador Resources Company 2012 Long-Term Incentive Plan dated April 16, 2012 (incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.9	Separation Agreement and Release by and between Matador Resources Company and Wade I. Massad, dated as of August 10, 2012 (filed herewith).
10.10	Consulting Agreement by and between Matador Resources Company and Wade I. Massad, dated as of August 10, 2012 (filed herewith).
23.1	Consent of Netherland, Sewell & Associates, Inc. (filed herewith).
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99.1	Audit report of Netherland, Sewell & Associates, Inc. (filed herewith).
101*	The following financial information from Matador Resources Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2012, formatted in XBRL (eXtensible Business Reporting Language): (i) the Condensed Consolidated Balance Sheets - Unaudited, (ii) the Condensed Consolidated Statements of Operations - Unaudited, (iii) the Condensed Consolidated Statement of Changes in Shareholders' Equity - Unaudited, (iv) the Condensed Consolidated Statements of Cash Flows - Unaudited and (v) the Notes to Condensed Consolidated Financial Statements (submitted electronically herewith).

* In accordance with Rule 406T of Regulation S-T, the XBRL information in Exhibit 101 to this quarterly report on Form 10-Q shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended ("Exchange Act"), or otherwise subject to the liability of that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

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SIGNATURES

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

		MATADOR RESOURCES COMPANY
Date: August 14, 2012	By:	/s/ Joseph Wm. Foran Joseph Wm. Foran Chairman, President and Chief Executive Officer
Date: August 14, 2012	By:	/s/ David E. Lancaster David E. Lancaster Executive Vice President, Chief Operating Officer and Chief Financial Officer

SEPARATION AGREEMENT AND RELEASE

This Separation Agreement and Release ("***Agreement***") is entered into by Matador Resources Company, a Texas corporation ("***Matador***" or "***the Company***"), and Wade I. Massad ("***Employee***") as of August 10, 2012 (the "***Agreement Date***"). Matador and Employee are referred to as the "***Parties.***" This Agreement cancels and supersedes all prior agreements relating to Employee's employment with Matador, including the Nonqualified Stock Option Agreement by and between Matador and Employee dated February 1, 2012 (the "***Stock Option Agreement***") except as provided in this Agreement.

WHEREAS, Matador and Employee entered into an Employment Agreement as of December 1, 2011 (the "***Employment Agreement***"). This Agreement is entered into by and between Employee and Matador pursuant to the Employment Agreement;

WHEREAS, because of Employee's employment as an employee of Matador, Employee has obtained intimate, proprietary and unique knowledge of all aspects of Matador's business operations, current and future plans, financial plans and other confidential and proprietary information;

WHEREAS, Employee's employment with Matador and all other positions, if any, held by Employee in Matador or any of its subsidiaries or affiliates, including officer positions, terminated effective as of July 31, 2012 ***(the*** "***Separation Date***");

WHEREAS, following the Separation Date and based upon the contributions Employee has made to Matador, Matador and Employee intend to enter into an arrangement whereby Employee will provide certain services to Matador on a consulting basis;

WHEREAS, except as otherwise provided herein, the Parties desire to finally, fully and completely resolve all matters that now or may exist between them, including, but not limited to those concerning the Employment Agreement (except for the post-termination obligations contained in the Employment Agreement), Employee's job performance and activities while employed by Matador and Employee's hiring, employment and separation from Matador, and all matters related to benefits and compensation connected with such employment;

NOW, THEREFORE, in consideration of the premises and mutual covenants and agreements hereinafter set forth, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereto agree as follows:

1. End of Employee's Employment. Employee's employment with Matador terminated on the Separation Date.

2. Certain Payments and Benefits.

(a) *Accrued Obligations*. In accordance with Matador's customary payroll practices, Matador shall pay Employee for all unpaid salary, unreimbursed business expenses, and any accrued but unused vacation through the Separation Date ("***Accrued Obligations***").

(b) _Payments_. Subject to Employee's consent to and fulfillment of Employee's obligations in this Agreement and Employee's post termination obligations in the Employment Agreement, provided that Employee does not revoke this Agreement pursuant to Section 12 hereof, Matador shall pay Employee the amount of $60,000, minus normal payroll withholdings and taxes, ("***Bonus Payment***"), payable in a lump sum payment. The Bonus Payment will not be treated as compensation under Matador's 401(k) Plan or any other retirement plan. If Employee is eligible for and timely elects continuation coverage under Matador's group health plan in accordance with the Consolidated Omnibus Reconciliation Act of 1985, as amended ("***COBRA***"), Matador agrees to pay the entire cost of the premiums for such coverage for Employee and his eligible dependents for the period of coverage beginning on July 31, 2012 and ending on the earliest of (i) December 31, 2012, (ii) the date that Employee obtains full-time employment with another employer or dies or (iii) the date Employee's coverage under Matador's health plan terminates for any reason (other than non-payment of premiums). Matador shall be under no obligation to pay the cost of such premiums if such payment subjects Matador to any penalty, excise or other tax associated with such payment or coverage. If Employee is eligible for additional COBRA continuation coverage after the expiration of the period set forth herein, Employee may continue such coverage, provided Employee shall be solely responsible for the payment of any premiums for such COBRA continuation coverage. Matador shall provide Employee under separate cover at his home address, information necessary and required by law regarding the COBRA election. Benefits provided under this Section 2(b) to Employee or his eligible dependents shall be modified to the extent benefits under an applicable plan are modified for active employees of Matador.

(c) _Waiver of Additional Compensation or Benefits_. Other than the compensation and payments provided for in this Agreement and the post-termination benefits provided for in this Agreement and in the Employment Agreement, Employee shall not be entitled to any additional compensation, benefits, payments or grants under any agreement, benefit plan, severance plan or bonus or incentive program established by Matador or any of Matador's affiliates, including, but not limited to the Stock Option Agreement, other than any vested retirement plan benefit or any vested equity grants. Employee agrees that the release in Paragraph 3 covers any claims Employee might have regarding Employee's compensation, bonuses, stock options or grants and any other benefits Employee may or may not have received during Employee's employment with Matador.

3. General Release and Waiver. In consideration of the payments and other consideration provided for in this Agreement, that being good and valuable consideration, the receipt, adequacy and sufficiency of which are acknowledged by Employee, Employee, on Employee's own behalf and on behalf of Employee's agents, administrators, representatives, executors, successors, heirs, devisees and assigns (collectively, the "***Releasing Parties***") hereby fully releases, remises, acquits and forever discharges Matador and all of its affiliates, and each of their respective past, present and future officers, directors, shareholders, equity holders, members, partners, agents, employees, consultants, independent contractors, attorneys, advisers, successors and assigns (collectively, the "***Released Parties***"), jointly and severally, from any and all claims, rights, demands, debts, obligations, losses, causes of action, suits, controversies, setoffs, affirmative defenses, counterclaims, third party actions, damages, penalties, costs, expenses, attorneys' fees, liabilities and indemnities of any kind or nature whatsoever (collectively, the "***Claims***"), whether known or unknown, suspected or unsuspected, accrued or unaccrued, whether at law, equity, administrative, statutory or otherwise, and whether for injunctive relief, back pay, fringe benefits, reinstatement, reemployment, or compensatory, punitive or any other kind of damages, which any of the Releasing Parties ever have had in the past or presently have against the Released Parties, and each of them, arising from or relating to Employee's employment with Matador or its affiliates or the termination of that employment or any circumstances related thereto, or (except as otherwise provided below) any other matter, cause or thing whatsoever, including without limitation all claims arising under or relating to employment, employment contracts, employee benefits or purported employment discrimination or violations of civil rights of whatever kind or nature, including without limitation all claims arising under the Age Discrimination in Employment Act ("ADEA"), the Americans with Disabilities Act as amended, the Family and Medical Leave Act of 1993, the Equal Pay Act of 1963, the Rehabilitation Act of 1973, Title VII of the United States Civil Rights Act of 1964, 42 U.S.C. § 1981, the Fair Labor Standards Act, the Employee Retirement Income Security Act, the Civil Rights Act of 1991, the Civil Rights Acts of 1866 and/or 1871, the Sarbanes-Oxley Act, the Genetic Information Nondiscrimination Act, the Lily Ledbetter Act, the Texas Commission on Human Rights Act, the Texas Payday Law, the Texas Labor Code or any other applicable federal, state or local employment statute, law or ordinance, including, without limitation, any disability claims under any such laws, claims for wrongful discharge, claims arising under state law, contract claims including breach of express or implied contract, alleged tortious conduct, claims relating to alleged fraud, breach of fiduciary duty or reliance, breach of implied covenant of good faith and fair dealing, and any other claims arising under state or federal law, as well as any expenses, costs or attorneys' fees. Employee further agrees that Employee will not file or permit to be filed on Employee's behalf any such claim. Notwithstanding the preceding sentence or any other provision of this Agreement, this release is not intended to interfere with Employee's right to file a charge with the Equal Employment Opportunity Commission (the "***EEOC***"), or other comparable agency, in connection with any claim Employee believes Employee may have against Matador or its affiliates. However, by executing this Agreement, Employee hereby waives the right to recover in any proceeding Employee may bring before the EEOC or any state human rights commission or in any proceeding brought by the EEOC or any state human rights commission on Employee's behalf. This release shall not apply to any of Matador's obligations under this Agreement or post-termination obligations under the Employment Agreement, any vested retirement plan, benefits, any vested equity grants or COBRA continuation coverage benefits. Employee acknowledges that certain of the payments and benefits provided for in Section 2 of this Agreement constitute good and valuable consideration for the release contained in this Section 3.

4. Return of Matador Property. Employee may retain all equipment, records, files, programs or other materials and property in Employee's possession which belong to Matador or any of its affiliates that are required for any services to be provided by Employee to Matador following the Separation Date on a consulting basis; however, at any time Matador may request a return of all such items and Employee shall promptly return such items to Matador.

5. Non-Disparagement. Employee agrees that Employee will not, directly or indirectly, disclose, communicate, or publish any disparaging information concerning Matador or the Released Parties, or cause others to disclose, communicate, or publish any disparaging information concerning the same. Matador, on its own behalf and on behalf of its officers and directors, agrees that they will not, directly or indirectly, disclose, communicate or publish any disparaging information concerning Employee, or cause others to disclose, communicate, or publish any disparaging information concerning Employee.

6. Change in Relationship. Nothing in this Agreement shall be construed in any way as an admission by either Party of any acts of wrongdoing, violation of any statute, law or legal or contractual right. Employee represents to Matador that he has faithfully fulfilled his duties under the Employment Agreement to date and both parties intend to enter into an arrangement whereby Employee will provide certain services to Matador on a consulting basis.

7. Voluntary Execution of the Agreement. Employee and Matador represent and agree that they have had an opportunity to review all aspects of this Agreement, and that they fully understand all the provisions of the Agreement and are voluntarily entering into this Separation Agreement and Release. Employee further represents that Employee has not transferred or assigned to any person or entity any claim involving Matador or any portion thereof or interest therein.

8. Ongoing Obligations. Employee reaffirms and understands Employee's ongoing obligations in the Employment Agreement, including Sections 8, 9, 10, 11 and 21.

9. Binding Effect. This Agreement shall be binding upon Matador and upon Employee and Employee's heirs, administrators, representatives, executors, successors and assigns and Matador's representatives. In the event of Employee's death, this Agreement shall operate in favor of Employee's estate and all payments, obligations and consideration will continue to be performed in favor of Employee's estate.

10. Severability. Should any provision of this Agreement be declared or determined to be illegal or invalid by any government agency or court of competent jurisdiction, the validity of the remaining parts, terms or provisions of this Agreement shall not be affected and such provisions shall remain in full force and effect.

11. Entire Agreement. Except for the post-termination obligations in the Employment Agreement, any vested retirement plan benefits and any vested equity grant agreements, this Agreement sets forth the entire agreement between the parties, and fully supersedes any and all prior agreements, understandings, or representations between the parties pertaining to Employee's employment with Matador, the subject matter of this Agreement or any other term or condition of the employment relationship between Matador and Employee. Employee represents and acknowledges that in executing this Agreement, Employee does not rely, and has not relied, upon any representation(s) by Matador or its agents except as expressly contained in this Agreement or the Employment Agreement. Employee and Matador agree that they have each used their own judgment in entering into this Agreement.

12. Knowing and Voluntary Waiver. Employee, by Employee's free and voluntary act of signing below, (i) acknowledges that Employee received this Agreement on July 24, 2012 and has been given a period of twenty-one (21) days to consider whether to agree to the terms contained herein, (ii) acknowledges that Employee has been advised to consult with an attorney prior to executing this Agreement, (iii) acknowledges that Employee understands that this Agreement specifically releases and waives all rights and claims Employee may have under the ADEA prior to the date on which Employee signs this Agreement, and (iv) agrees to all of the terms of this Agreement and intends to be legally bound thereby. The Parties acknowledge and agree that each Party has reviewed and negotiated the terms and provisions of this Agreement and has contributed to its preparation (with advice of counsel). Accordingly, the rule of construction to the effect that ambiguities are resolved against the drafting party shall not be employed in the interpretation of this Agreement. Rather, the terms of this Agreement shall be construed fairly as to both Parties and not in favor of or against either Party, regardless of which Party generally was responsible for the preparation of this Agreement.

This Agreement will become effective, enforceable and irrevocable on the eighth day after the date on which it is executed by Employee ***(the* "*Effective Date*"**). During the seven-day period prior to the Effective Date, Employee may revoke Employee's agreement to accept the terms hereof by giving notice to Matador of Employee's intention to revoke. If Employee exercises Employee's right to revoke hereunder, Employee shall not be entitled, except as required by applicable wage payment laws, including, but not limited to, Accrued Obligations, to any payment hereunder until Employee executes and does not revoke a comparable release of claims, and to the extent such payments or benefits have already been made, Employee agrees that Employee will immediately reimburse Matador for the amounts of such payments and benefits to which he is not entitled.

13. Notices. All notices and other communications hereunder will be in writing. Any notice or other communication hereunder shall be deemed duly given if it is delivered personally or sent by registered or certified mail, return receipt requested, postage prepaid, and addressed to the intended recipient as set forth:

If to Employee:

Wade I. Massad
____
____

If to Matador Resources Company:

Matador Resources Company
One Lincoln Centre
5400 LBJ Freeway, Suite 1500
Dallas, TX 75240
Attention: Board of Directors

Any Party may change the address to which notices and other communications are to be delivered by giving the other Party notice.

14. Governing Law; Venue; Arbitration. This section of the Agreement shall be governed by Section 23 of the Employment Agreement.

15. Counterparts. This Agreement may be executed in counterparts, each of which when executed and delivered (which deliveries may be by facsimile or other electronic method of delivery) shall be deemed an original and all of which together shall constitute one and the same instrument.

16. No Assignment of Claims. Employee represents and agrees that Employee has not transferred or assigned, to any person or entity, any claim involving Matador, or any portion thereof or interest therein.

17. No Waiver. This Agreement may not be waived, modified, amended, supplemented, canceled or discharged, except by written agreement of the Parties. Failure to exercise and/or delay in exercising any right, power or privilege in this Agreement shall not operate as a waiver. No waiver of any breach of any provision shall be deemed to be a waiver of any preceding or succeeding breach of the same or any other provision, nor shall any waiver be implied from any course of dealing between or among the Parties.

I ACKNOWLEDGE THAT I HAVE CAREFULLY READ THE FOREGOING AGREEMENT, THAT I UNDERSTAND ALL OF ITS TERMS AND THAT I AM RELEASING CLAIMS AND THAT I AM ENTERING INTO IT VOLUNTARILY.

AGREED TO BY:

/s/ Wade I. Massad
WADE I. MASSAD

August 10, 2012
Date

STATE OF TEXAS

COUNTY OF DALLAS

Before me, a Notary Public, on this day personally appeared Wade I. Massad, known to me to be the person whose name is subscribed to the foregoing instrument, and acknowledges to me that he has executed this Agreement on behalf of himself and his heirs, for the purposes and consideration therein expressed.

Given under my hand and seal of office this 10th day of August, 2012

/s/ Amanda Crawford
Notary Public in and for the State of Texas

(PERSONALIZED SEAL)

MATADOR RESOURCES COMPANY

By: /s/ David E. Lancaster
David E. Lancaster
Executive Vice President

Date: August 10, 2012

STATE OF TEXAS

COUNTY OF DALLAS

Before me, a Notary Public, on this day personally appeared David E. Lancaster, known to me to be the person and officer whose name is subscribed to the foregoing instrument and acknowledged to me that the same was the act of Matador Resources Company, and that he has executed the same on behalf of said corporation for the purposes and consideration therein expressed, and in the capacity therein stated.

Given under my hand and seal of office this 10th day of August, 2012.

/s/ Amanda Crawford
Notary Public in and for the State of Texas

(PERSONALIZED SEAL)

CONSULTING AGREEMENT

This Consulting Agreement ("Agreement") is made and entered into by and between Matador Resources Company ("Matador") and **Wade I. Massad**, as consultant ("Consultant"), to be effective on the date this Agreement is executed by the last party to sign below.

WITNESSETH:

WHEREAS, Consultant previously provided services to Matador as a capital markets consultant before becoming an employee prior to Matador's initial public offering (the "IPO") to provide Matador with the benefits of his capital markets experience and expertise;

WHEREAS, the IPO having been completed in March 2012, both Matador and Consultant desire to return to the consulting arrangement that existed prior to the IPO with Consultant providing services as a capital markets consultant for the period and on the basis set forth herein, and Consultant desires to be so retained by Matador;

NOW, THEREFORE, in consideration of the mutual promises and covenants herein contained, the parties hereto agree as follows:

1. Matador hereby retains Consultant as a capital markets consultant to Matador for the time and on the basis set forth herein and Consultant agrees to provide consulting services to Matador, acknowledging that Consultant will provide such services in a fiduciary capacity to Matador.

2. Matador shall retain Consultant as a capital markets consultant and the term of this Agreement shall commence on the date Consultant first performs services for Matador, which is anticipated to be on or about August 1, 2012, and shall continue on a month-to-month basis (the "Term"), unless earlier terminated in accordance with Paragraph 9.

3. Throughout the Term of this Agreement, Consultant hereby accepts and agrees to devote his best efforts in the interests of Matador to the performance of the Services (as defined below). During the Term of this Agreement, Consultant agrees not to accept employment with or provide services for any other party if the possibility exists that there may be a conflict of interest between Matador and such party. In such case, Consultant agrees to advise Matador in writing in advance of any potential opportunities for employment with, or the provision of services to, any such party, and may not accept such employment or provide any services to such party until he has received confirmation in writing from Matador that in Matador's sole judgment no conflict of interest exists. Notwithstanding anything to the contrary in this Agreement, Consultant reaffirms and understand Consultant's ongoing obligations in that certain employment agreement dated December 1, 2011 between Consultant and Matador (the "Employment Agreement"), including Sections 8, 9, 10, 11 and 21.

4. Consultant shall report to Matador's Chairman and CEO, Joseph Wm. Foran, or his successors and/or such other personnel of Matador or its parent or affiliated companies as designated from time to time by Joseph Wm. Foran or his successor.

5. This Agreement and Consultant's services hereunder shall involve the following services (the "Services") during the Term:

Consultant shall work on such projects and areas of responsibility and provide such other general and specific services as are coordinated by the Matador staff with Consultant, and shall communicate and keep the Matador staff apprised of Consultant's plans and progress on such projects and areas of responsibility.

6. As compensation for the Services, Matador agrees to pay Consultant a fee of $7,500 per month. Such fee is inclusive of Consultant's ordinary daily expenses incidental to performing the Services while at Matador's premises but is exclusive of and Consultant shall be entitled to reimbursement by Matador for all reasonable travel expenses incurred in accordance with Matador's policies in effect, which shall be payable by Matador, in arrears, such as mileage, overnight parking, lodging and meals. Consultant shall be responsible for the payment of all taxes associated with the amounts received pursuant to this Agreement.

7. During the Term, Matador may disclose to Consultant information which Matador considers confidential and proprietary. In addition, Matador considers Consultant's efforts and Services hereunder to be confidential and proprietary information. Consultant agrees not to publish or disclose any such information to others without the prior written consent of Matador. In the event that Consultant receives a request or is required (by deposition, interrogatory, request for documents, subpoena, civil investigative demand or similar process) to disclose all or any part of confidential and proprietary information received by Consultant, Consultant agrees to immediately notify Matador in writing of any such request or requirement so that Matador may seek an appropriate protective order, or waive compliance with the provisions hereof. If, failing the entry of a protective order or the receipt of a waiver hereunder, Consultant may disclose that portion of the confidential information which Consultant is advised by counsel is legally required to be disclosed, and shall exercise Consultant's reasonable efforts to obtain assurance that confidential treatment will be accorded such confidential information and Consultant shall not be liable for such disclosure unless such disclosure was caused by or resulted from a previous disclosure by Consultant not permitted by this Agreement. As to the above confidential disclosure to Consultant by Matador and Consultant's efforts and Services hereunder, the obligation of confidence shall extend from the termination of this Agreement but shall not apply to (a) information that is or becomes known to the general public through no act of Consultant or (b) information which Consultant receives from a third party having the lawful right to disclose such information without breach of any obligation of confidentiality. Consultant shall not employ others to assist with the provision of Services covered by this Agreement. Upon termination of this Agreement, Consultant shall surrender to Matador all of Consultant's work product and all data and information obtained by, utilized by or provided to Consultant in furtherance of this Agreement and Consultant shall not retain any such work product, information or data, or any copies thereof. Consultant and Matador agree that Section 9 of the Employment Agreement governing non-competition and non-solicitation is incorporated herein with the twelve month "Restricted Period" beginning upon the date of termination of this Agreement according to Paragraph 9 hereof.

8. During the Term of this Agreement, Consultant will be an independent contractor and Consultant shall not be an employee of Matador or of any of its affiliates, and Consultant will not represent himself as an employee of Matador or any of its affiliates to any party or parties. Consultant shall therefore render the Services on a consultancy basis as a professional, without any bond of employment. The parties confirm and assent that Consultant shall not be subject or entitled to any of Matador's employee benefits. Consultant shall provide all tools and equipment necessary to perform the Services hereunder except that Matador may offer to provide certain equipment, software and/or tools for projects it assigns to Consultant and Consultant may elect at his sole discretion to utilize the equipment, software and/or tools for the performance of Services. The parties confirm and assent that Consultant has the right of control on how Services provided hereunder are completed. Consultant shall be responsible for the payment of all taxes associated with amounts received pursuant to this Agreement. Except as otherwise provided in that certain Separation Agreement and Release between Consultant and Matador dated August 10, 2012, Consultant shall carry such insurance as Consultant deems necessary or desirable and Matador shall not be liable to Consultant for the premiums on any such insurance policies issued to Consultant on Consultant's behalf. Matador shall not be required to carry for Consultant's benefit any worker's compensation or industrial or occupational disease insurance. Likewise, it is not the intention of the parties hereto to create, expressly or impliedly, a partnership, association or joint venture, and any such partnership, association or joint venture status is hereby expressly denied. Upon reasonable prior written notice, Matador or its designated agents shall be permitted access to all books and records of Consultant reasonably related to the payments made hereunder and to the performance by Consultant of the Services hereunder, including for the purpose of auditing such books and records, all at the expense of Matador.

9. This Agreement may be terminated by Matador or by Consultant at any time with not less than thirty (30) days prior written notice. In the event that Matador gives notice to terminate this Agreement, Matador shall have no further obligation to pay Consultant hereunder except for actual hours of Services completed by Consultant as of termination by Matador. If Consultant terminates this Agreement, Consultant shall be entitled to all compensation for actual hours of Services completed by Consultant as of termination by Consultant. Neither termination nor completion of this Agreement referred to above shall affect Paragraphs 7, 8 and 10, which provisions shall survive the termination of this Agreement and remain operative and in full force and effect. Notwithstanding the foregoing, this Agreement may be terminated by Matador without prior notice in the event of the disability, incapacity, bankruptcy or insolvency of Consultant to such an extent as to render Consultant unable, in the sole opinion of Matador, to perform the Services.

10. After this Agreement has been terminated in accordance with Paragraph 9, Consultant shall, upon the written request of Matador, make himself available to further perform the Services as reasonably requested by Matador to ensure a smooth transition and termination of this Agreement. Consultant shall cooperate with Matador in the completion, clarification and winding up of any Services previously provided by Consultant and assist Matador in the handling of any disputes or claims related to the Services. Any such Services provided after the Term has ended shall be subject to all of the provisions of this Agreement, including but not limited to, payment in accordance with Paragraph 6.

11. Except as otherwise agreed in writing by the parties hereto, all amounts paid to Consultant shall be paid in legal tender of the United States, and shall be by check or wire transfer.

12. This Agreement as to Consultant is personal and may not be assigned or otherwise transferred by Consultant. Matador, however, shall have the right to assign this Agreement to any of its affiliates or successors. This Agreement may not be amended except by written instrument signed by both parties, and no waiver shall be enforceable against any party unless evidenced by a written instrument signed by the party against which enforcement is sought.

13. This Agreement shall in all respects be subject to, and governed by, the laws of the State of Texas. Matador and Consultant agree and consent to the personal jurisdiction of the state and local courts of Dallas County, Texas and/or the United States District Court for the Northern District of Texas in the event that Matador or Consultant seeks injunctive relief with respect to any provision hereof, and that those courts, and only those courts, shall have jurisdiction with respect thereto. Matador and Consultant also agree that those courts are convenient forums for the parties and for any potential witnesses and that process issued out of any such court or in accordance with the rules of practice of that court may be served by mail or other forms of substituted service to Matador at the address of its principal executive offices and to Consultant at his last known address as reflected in Matador’s records.

14. In the event of any dispute, claim, question or disagreement relating to this Agreement, other than one for which Matador or Consultant seeks injunctive relief, the parties shall use their best efforts to settle the dispute, claim, question or disagreement. To this effect, they shall consult and negotiate with each other in good faith and, recognizing their mutual interests, attempt to reach a just and equitable solution satisfactory to both parties. If such a dispute cannot be settled through negotiation, the parties agree first to try in good faith to settle the dispute by mediation administered by the American Arbitration Association (the “AAA”) under its Commercial Mediation Rules before resorting to arbitration or some other dispute resolution procedure. If the parties do not reach such solution through negotiation or mediation within a period of sixty (60) days after a claim is first made by a party, then, upon notice by either party to the other, all disputes, claims, questions or disagreements shall be finally settled by arbitration administered by the AAA in accordance with the provisions of its Commercial Arbitration Rules. The arbitrator shall be selected by agreement of the parties or, if they do not agree on an arbitrator within thirty (30) days after either party has notified the other of his or its desire to have the question settled by arbitration, then the arbitrator shall be selected pursuant to the procedures of the AAA, with such arbitration taking place in Dallas, Texas. The determination reached in such arbitration shall be final and binding on all parties. Enforcement of the determination by such arbitrator may be sought in any court of competent jurisdiction.

15. Failure of either party hereto to insist upon or require strict compliance with any provision hereof shall not be considered a waiver of such provision or modification of this Agreement unless so specified in writing. The provisions of this Agreement are severable and the invalidity or unenforceability of one or more of the provisions herein shall not have any effect on the validity or enforceability of any other provision. This Agreement may be executed in counterparts, all of which, taken together, shall constitute one and the same original document.

16. Consultant represents that he is either a U.S. Citizen or has the legal right under the laws of the U.S.A. to enter into this Agreement and to provide the Services hereunder, and that he will immediately advise Matador in the event his legal status should change.

IN WITNESS WHEREOF, Matador has caused this Agreement to be executed on its behalf by its duly authorized corporate officer and Consultant has hereunto set his hand as of the date set forth underneath each respective signature below.

<u>Signature and address for Notice</u>:
Address:

MATADOR RESOURCES COMPANY
One Lincoln Centre
5400 LBJ Freeway, Suite 1500
Dallas, Texas 75240

/s/ David E. Lancaster
David E. Lancaster
Executive Vice President

Date: August 10, 2012

<u>Signature and address for Notice</u>:
Address:

WADE I. MASSAD

/s/ Wade I. Massad
Wade I. Massad

Date: August 10, 2012

Exhibit 23.1

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the use of the name Netherland, Sewell & Associates, Inc., the references to our audits of Matador Resources Company's proved oil and natural gas reserves estimates and future net revenue at June 30, 2012, and the inclusion of our corresponding audit letter, dated July 24, 2012, in the Quarterly Report on Form 10-Q of Matador Resources Company for the fiscal quarter ended June 30, 2012, as well as in the notes to the financial statements included therein. In addition, we hereby consent to the incorporation by reference to our audit letter, dated July 24, 2012 in Matador Resources Company's Form S-8 (333-180641).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Robert C. Barg
Robert C. Barg, P.E.
Senior Vice President

Dallas, Texas
August 13, 2012

Exhibit 31.1

CERTIFICATION

I, Joseph Wm. Foran, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Matador Resources Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b. Paragraph omitted pursuant to Exchange Act Rule 13a-14(a);

c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

August 14, 2012

/s/ Joseph Wm. Foran
Joseph Wm. Foran
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, David E. Lancaster, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Matador Resources Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b. Paragraph omitted pursuant to Exchange Act Rule 13a-14(a);

c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

August 14, 2012

/s/ David E. Lancaster

David E. Lancaster
Executive Vice President, Chief Operating Officer and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the quarterly report of Matador Resources Company (the "Company") on Form 10-Q for the period ended June 30, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-Q"), I, Joseph Wm. Foran, Chairman, President and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Form 10-Q fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company.

August 14, 2012	/s/ Joseph Wm. Foran
	Joseph Wm. Foran
	Chairman, President and Chief Executive Officer
	(Principal Executive Officer)

Exhibit 32.2

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the quarterly report of Matador Resources Company (the “Company”) on Form 10-Q for the period ended June 30, 2012 as filed with the Securities and Exchange Commission on the date hereof (the “Form 10-Q”), I, David E. Lancaster, Executive Vice President, Chief Operating Officer and Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Form 10-Q fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company.

August 14, 2012

/s/ David E. Lancaster
David E. Lancaster
Executive Vice President, Chief Operating Officer and Chief Financial Officer
(Principal Financial Officer)

Exhibit 99.1

July 24, 2012

Mr. lndranil (Neil) Barman
MRC Energy Company
One Lincoln Centre
5400 LBJ Freeway,Suite 1500
Dallas, Texas 75240

Dear Mr. Barman:

In accordance with your request, we have audited the estimates prepared by MRC Energy Company (MRC), as of June 30, 2012, of the proved reserves and future revenue to the MRC interest in certain oil and gas properties located in Louisiana, New Mexico, and Texas. It is our understanding that the proved reserves estimates shown herein constitute all of the proved reserves owned by MRC. We have examined the estimates with respect to reserves quantities, reserves categorization, future producing rates, future net revenue, and the present value of such future net revenue, using the definitions set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Rule 4-10(a). The estimates of reserves and future revenue have been prepared in accordance with the definitions and regulations of the SEC and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. We completed our audit on or about the date of this letter. This report has been prepared for MRC's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

The following table sets forth MRC's estimates of the net reserves and future net revenue, as of June 30, 2012, for the audited properties:

	Net Reserves		Future Net Revenue (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	3,128	53,079	323,287	217,570
Proved Developed Non-Producing	6	906	1,430	745
Proved Undeveloped	3,595	19,959	198,058	85,070
Total Proved	6,728	73,943	522,775	303,385

Totals may not add because of rounding.

The oil reserves shown include crude oil and condensate. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

When compared on a well-by-well basis, some of the estimates of MRC are greater and some are less than the estimates of Netherland, Sewell & Associates, Inc. (NSAI). However, in our opinion the estimates of MRC's proved reserves and future revenue shown herein are, in the aggregate, reasonable and have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). Additionally, these estimates are within the recommended 10 percent tolerance threshold set forth in the SPE Standards. We are satisfied with the methods and procedures used by MRC in preparing the June 30, 2012, estimates of reserves and future revenue, and we saw nothing of an unusual nature that would cause us to take exception with the estimates, in the aggregate, as prepared by MRC.

The estimates shown herein are for proved reserves. MRC's estimates do not include probable or possible reserves that may exist for these properties, nor do they include any value for undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Prices used by MRC are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period July 2011 through June 2012. For oil volumes, the average West Texas Intermediate posted price of $92.17 per barrel is adjusted by lease for quality, transportation fees, and regional price differentials. For gas volumes, the average Henry Hub spot price of $3.146 per MMBTU is adjusted by lease for energy content, transportation fees, and regional price differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $100.41 per barrel of oil and $2.89 per MCF of gas.

Operating costs used by MRC are based on historical operating expense records. For nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs for the operated properties include direct lease- and field-level costs and MRC's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Capital costs used by MRC are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Operating costs are held constant throughout the lives of the properties, and capital costs are held constant to the date of expenditure.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, estimates of MRC and NSAI are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing these estimates.

It should be understood that our audit does not constitute a complete reserves study of the audited oil and gas properties. Our audit consisted primarily of substantive testing, wherein we conducted a detailed review of all properties. In the conduct of our audit, we have not independently verified the accuracy and completeness of information and data furnished by MRC with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of our examination something came to our attention that brought into question the validity or sufficiency of any such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data. Our audit did not include a review of MRC's overall reserves management processes and practices.

We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to establish the conclusions set forth herein. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Supporting data documenting this audit, along with data provided by MRC, are on file in our office. The technical persons responsible for conducting this audit meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ G. Lance Binder
G. Lance Binder
Texas P.E. 61794
Executive Vice President

Date Signed: July 24, 2012

By: /s/ David T. Miller
David T. Miller
Louisiana P.E. 22695
Vice President

Date Signed: July 24, 2012

GLB:JTE

NETHERLAND, SEWELL & ASSOCIATES, INC.

CERTIFICATION OF QUALIFICATION

I, G. Lance Binder, Registered Professional Engineer, 4500 Thanksgiving Tower, 1601 Elm Street, Dallas, Texas, hereby certify:

That I am an employee of Netherland, Sewell & Associates, Inc. in the position of Executive Vice President.

That I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Matador Resources Company or its subsidiaries.

That I attended Purdue University and graduated in 1978 with a Bachelor of Science Degree in Chemical Engineering; that I am a Registered Professional Engineer in the State of Texas, United States of America; and that I have in excess of 33 years experience in petroleum engineering studies and evaluations.

By: /s/ G. Lance Binder

G. Lance Binder, P.E.
Texas Registration No. 61794