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 March 31, 2013

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** (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 May 9, 2013, there were 55,862,157 shares of the registrant's common stock, par value $0.01 per share, outstanding.

MATADOR RESOURCES COMPANY
FORM 10-Q
FOR THE QUARTER ENDED MARCH 31, 2013

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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)

	March 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash	$ 4,652	$ 2,095
Certificates of deposit	141	230
Accounts receivable		
Oil and natural gas revenues	22,232	24,422
Joint interest billings	4,862	4,118
Other	668	974
Derivative instruments	1,142	4,378
Deferred income taxes	1,008	-
Lease and well equipment inventory	966	877
Prepaid expenses	1,597	1,103
Total current assets	37,268	38,197
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	830,254	763,527
Unproved and unevaluated	151,161	149,675
Other property and equipment	27,596	27,258
Less accumulated depletion, depreciation and amortization	(398,832)	(349,370)
Net property and equipment	610,179	591,090
Other assets		
Derivative instruments	1,143	771
Deferred income taxes	-	411
Other assets	1,732	1,560
Total other assets	2,875	2,742
Total assets	$ 650,322	$ 632,029
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 19,675	$ 28,120
Accrued liabilities	40,214	59,179
Royalties payable	7,706	6,541
Derivative instruments	2,215	670
Advances from joint interest owners	2,549	1,515
Income taxes payable	46	-
Deferred income taxes	-	411
Other current liabilities	78	56
Total current liabilities	72,483	96,492
Long-term liabilities		
Borrowings under Credit Agreement	205,000	150,000
Asset retirement obligations	5,746	5,109
Derivative instruments	416	-
Deferred income taxes	1,008	-
Other long-term liabilities	1,564	1,324
Total long-term liabilities	213,734	156,433
Commitments and contingencies (Note 9)		
Shareholders' equity		
Common stock - $0.01 par value, 80,000,000 shares authorized; 57,104,489 and 56,778,718 shares issued; and 55,842,938 and 55,577,667 shares outstanding, respectively	571	568
Additional paid-in capital	404,814	404,311
Retained deficit	(30,515)	(15,010)
Treasury stock, at cost, 1,261,551 and 1,201,051 shares, respectively	(10,765)	(10,765)
Total shareholders' equity	364,105	379,104
Total liabilities and shareholders' equity	$ 650,322	$ 632,029

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

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Matador Resources Company and Subsidiaries

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

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Revenues		
Oil and natural gas revenues	$ 59,319	$29,164
Realized gain on derivatives	392	3,063
Unrealized loss on derivatives	(4,825)	(3,270)
Total revenues	54,886	28,957
Expenses		
Production taxes and marketing	4,097	2,165
Lease operating	10,899	4,645
Depletion, depreciation and amortization	28,232	11,205
Accretion of asset retirement obligations	81	53
Full-cost ceiling impairment	21,230	-
General and administrative	4,602	3,789
Total expenses	69,141	21,857
Operating (loss) income	(14,255)	7,100
Other income (expense)		
Interest expense	(1,271)	(308)
Interest and other income	67	73
Total other expense	(1,204)	(235)
(Loss) income before income taxes	(15,459)	6,865
Income tax provision		
Current	46	-
Deferred	-	3,064
Total income tax provision	46	3,064
Net (loss) income	$(15,505)	$ 3,801
Earnings (loss) per common share		
Basic		
Class A	$ (0.28)	$ 0.08
Class B	$ -	$ 0.15
Diluted		
Class A	$ (0.28)	$ 0.08
Class B	$ -	$ 0.15
Weighted average common shares outstanding		
Basic		
Class A	55,272	49,597
Class B	-	419
Total	55,272	50,016
Diluted		
Class A	55,272	49,666
Class B	-	419
Total	55,272	50,085

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

Matador Resources Company and Subsidiaries

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

For the Three Months Ended March 31, 2013

	Common Stock		Additional Paid-In	Retained	Treasury Stock		
	Shares	Amount	Capital	Deficit	Shares	Amount	Total
Balance at January 1, 2013	56,779	$ 568	$ 404,311	$ (15,010)	1,201	$ (10,765)	$ 379,104
Common stock issued to Board advisors	1	-	8	-	-	-	8
Stock options expense related to equity based awards	-	-	200	-	-	-	200
Liability based stock option awards forfeited or expired	-	-	42	-	-	-	42
Changes in fair value for liability based awards for which grant date fair value is in excess of fair value	-	-	2	-	-	-	2
Restricted stock issued	324	3	(3)	-	-	-	-
Restricted stock forfeited	-	-	(21)	-	60	-	(21)
Restricted stock and restricted stock units expense	-	-	275	-	-	-	275
Current period net loss	-	-	-	(15,505)	-	-	(15,505)
Balance at March 31, 2013	57,104	$ 571	$ 404,814	$ (30,515)	1,261	$ (10,765)	$ 364,105

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)

	Three Months Ended March 31,	
	2013	2012
Operating activities		
Net (loss) income	$(15,505)	$ 3,801
Adjustments to reconcile net (loss) income to net cash provided by operating activities		
Unrealized loss on derivatives	4,825	3,270
Depletion, depreciation and amortization	28,232	11,205
Accretion of asset retirement obligations	81	53
Full-cost ceiling impairment	21,230	-
Stock-based compensation expense	492	(363)
Deferred income tax provision	-	3,064
Changes in operating assets and liabilities		
Accounts receivable	1,752	(8,456)
Lease and well equipment inventory	121	-
Prepaid expenses	(493)	(544)
Other assets	(172)	13
Accounts payable, accrued liabilities and other current liabilities	(10,788)	(8,563)
Royalties payable	1,165	1,341
Advances from joint interest owners	1,034	-
Income taxes payable	46	-
Other long-term liabilities	209	289
Net cash provided by operating activities	32,229	5,110
Investing activities		
Oil and natural gas properties capital expenditures	(83,387)	(51,959)
Expenditures for other property and equipment	(1,374)	(1,413)
Purchases of certificates of deposit	(61)	(150)
Maturities of certificates of deposit	150	758
Net cash used in investing activities	(84,672)	(52,764)
Financing activities		
Repayments of borrowings under Credit Agreement	-	(123,000)
Borrowings under Credit Agreement	55,000	25,000
Proceeds from issuance of common stock	-	146,510
Cost to issue equity	-	(11,330)
Proceeds from stock options exercised	-	2,660
Payment of dividends - Class B	-	(96)
Net cash provided by financing activities	55,000	39,744
Increase (decrease) in cash	2,557	(7,910)
Cash at beginning of period	2,095	10,284
Cash at end of period	$ 4,652	$ 2,374

Supplemental disclosures of cash flow information (Note 10)

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" and, collectively, with its subsidiaries, the "Company") is 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. The Company's current operations are focused primarily on the oil and liquids rich portion of the Eagle Ford shale play in South Texas and the Wolfcamp and Bone Spring plays in Southeast New Mexico and West Texas. The Company also operates in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. In addition, the Company has a large exploratory leasehold position in Southwest Wyoming and adjacent areas of Utah and Idaho where the Company is testing the Meade Peak shale.

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, 2012 filed with the SEC (the "Annual Report"). 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 March 31, 2013, consolidated results of operations for the three months ended March 31, 2013 and 2012, consolidated changes in shareholders' equity for the three months ended March 31, 2013 and consolidated cash flows for the three months ended March 31, 2013 and 2012. 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, 2012 are derived from the audited consolidated financial statements in Matador's Annual Report.

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, natural gas and natural gas liquids prices, global economic and financial market conditions, interest rates, access to sources of liquidity, estimates of reserves, drilling risks, geological risks, transportation restrictions, oil, natural gas and natural gas liquids supply and demand, market competition and interruptions of production.

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 period. 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.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

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 $0.7 million and $0.5 million of its general and administrative costs for the three months ended March 31, 2013 and 2012, respectively. The Company capitalized approximately $0.3 million of its interest expense for each of the three months ended March 31, 2013 and 2012.

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 April 2012 through March 2013, these average oil and natural gas prices were $89.17 per Bbl and $2.950 per MMBtu (million British thermal units), respectively. For the period April 2011 through March 2012, these average oil and natural gas prices were $94.65 per Bbl and $3.731 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 March 31, 2013 and 2012, 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.

Using the average commodity prices, as adjusted, to determine the Company's estimated proved oil and natural gas reserves at March 31, 2013, the Company's net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $13.7 million. The Company recorded an impairment charge of $21.2 million to its net capitalized costs and a deferred income tax credit of $7.5 million, related to the full-cost ceiling limitation at March 31, 2013. Corresponding charges were also recorded to the Company's unaudited condensed consolidated statement of operations for the three months ended March 31, 2013. At March 31, 2013, the Company retained a full valuation allowance against its deferred tax assets, and as a result, the income tax benefit of $7.5 million is not reflected in the unaudited condensed consolidated statement of operations for the three months ended March 31, 2013. Using the average commodity prices, as adjusted, to determine the Company's estimated proved oil and natural gas reserves at March 31, 2012, the Company's net capitalized costs less related deferred income taxes did not exceed the full-cost ceiling. As a result, the Company recorded no impairment to its net capitalized costs for the three months ended March 31, 2012. 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 consolidated balance sheet, as well as the corresponding consolidated shareholders' equity, but it has no impact on the Company's consolidated net cash flows as reported.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

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 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 March 31, 2013 and 2012 totaled zero and $27,643, respectively. 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 March 31, 2013, 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.

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 months ended March 31, 2013 and 2012 (in thousands, except per share data).

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Net income (loss) — numerator		
Net (loss) income	$(15,505)	$ 3,801
Less dividends to Class B shareholders — distributed earnings	-	(28)
Undistributed (loss) earnings	$(15,505)	$ 3,773
Weighted average common shares outstanding — denominator		
Basic		
Class A	55,272	49,597
Class B	-	419
Total	55,272	50,016
Diluted		
Class A		
Weighted average common shares outstanding for basic earnings (loss) per share	55,272	49,597
Dilutive effect of options and restricted stock units	-	69
Class A weighted average common shares outstanding - diluted	55,272	49,666
Class B		
Weighted average common shares outstanding – no associated dilutive shares	-	419
Total diluted weighted average common shares outstanding	55,272	50,085

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Earnings (loss) per common share		
Basic		
Class A		
Distributed earnings	$ -	$ -
Undistributed (loss) earnings	$ (0.28)	$ 0.08
Total	$ (0.28)	$ 0.08
Class B		
Distributed earnings	$ -	$ 0.07
Undistributed earnings	$ -	$ 0.08
Total	$ -	$ 0.15
Diluted		
Class A		
Distributed earnings	$ -	$ -
Undistributed (loss) earnings	$ (0.28)	$ 0.08
Total	$ (0.28)	$ 0.08
Class B		
Distributed earnings	$ -	$ 0.07
Undistributed earnings	$ -	$ 0.08
Total	$ -	$ 0.15

A total of 1,434,861 options to purchase shares of the Company's Class A common stock and 68,607 restricted stock units were excluded from the calculations above for the three months ended March 31, 2013, because their effects were anti-dilutive. There were no outstanding restricted stock units at March 31, 2012. Additionally, 570,078 restricted shares, which are participating securities, were excluded from the calculations above for the three months ended March 31, 2013, as the security holders do not have the obligation to share in the losses of the Company.

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.

Recent Accounting Pronouncements

Balance Sheet. In January 2013, the FASB issued Accounting Standards Update, or ASU, 2013-01, *Balance Sheet.* The ASU clarifies the scope of ASU 2011-11 to limit the application of ASU 2011-11 to derivatives accounted for in accordance with Accounting Standards Codification, or ASC, 815, *Derivatives and Hedging*, including bifurcated embedded derivatives, repurchase and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with ASC 210-20-45 or ASC 815-10-45 or subject to an enforceable master netting arrangement or similar agreement. The adoption of ASU 2013-01 did not have a material effect on our consolidated financial statements but did require certain additional disclosures (see Note 7).

Balance Sheet. In December 2011, the FASB issued ASU 2011-11, *Balance Sheet.* The requirements amend the disclosure requirements related to offsetting in 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 did not have a material effect on the Company's consolidated financial statements but did require certain additional disclosures (see Note 7).

NOTE 3 - ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company's asset retirement obligations for the three months ended March 31, 2013 (in thousands).

Beginning asset retirement obligations	$5,769
Liabilities incurred during period	116
Liabilities settled during period	-
Revisions in estimated cash flows	540
Accretion expense	81
Ending asset retirement obligations	6,506
Less: current asset retirement obligations[1]	(760)
Long-term asset retirement obligations	$5,746

(1) Included in accrued liabilities in the Company's unaudited condensed consolidated balance sheet at March 31, 2013.

NOTE 4 - REVOLVING CREDIT AGREEMENT

On September 28, 2012, the Company amended and restated its revolving credit agreement. This third amended and restated credit agreement (the "Credit Agreement") increased the maximum facility amount from $400.0 million to $500.0 million, increased the borrowing base from $125.0 million to $200.0 million and named Royal Bank of Canada ("RBC") as the administrative agent. In addition, the amendment provided for a conforming borrowing base of $165.0 million. The borrowing base will automatically be reduced to the conforming borrowing base on the earlier of (i) December 31, 2013 or (ii) the closing of a secondary public offering of equity interests that results in net cash proceeds to the Company in an amount greater than or equal to $25.0 million. The Credit Agreement matures December 29, 2016. MRC Energy Company is the borrower under the Credit Agreement. 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 certain of the lenders under the Credit Agreement (or affiliates thereof) are also secured by the collateral of and guaranteed by the eligible subsidiaries of MRC Energy Company.

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 at December 31 and June 30 of each year, respectively. Both the Company and the lenders may request an unscheduled redetermination of the borrowing base once each between scheduled redetermination dates. During the fourth quarter of 2012, the Company requested one such unscheduled redetermination, and on December 20, 2012, the borrowing base was increased from $200.0 million to $215.0 million as a result of the lenders' review of the Company's proved oil and natural gas reserves at September 30, 2012. In connection with this borrowing base redetermination, the conforming borrowing base was increased to $180.0 million at December 20, 2012.

During the first quarter of 2013, the lenders completed their review of the Company's proved oil and natural gas reserves at December 31, 2012, and as a result, on March 11, 2013, the borrowing base was increased to $255.0 million and the conforming borrowing base was increased to $220.0 million. At that time, the Company also amended the Credit Agreement to include Capital One, N.A., BMO Harris Financing, Inc. (Bank of Montreal) and IberiaBank in the Company's lending group, which also includes RBC as administrative agent, Comerica Bank, Citibank, N.A., The Bank of Nova Scotia and SunTrust Bank. This most recent redetermination constituted the regularly scheduled May 1 redetermination. 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 is determined based on market conditions at the time of the borrowing base increase. If, upon a redetermination or the automatic reduction of the borrowing base to the conforming borrowing base, 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.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 4 - REVOLVING CREDIT AGREEMENT - Continued

The Company incurred $0.8 million of additional deferred loan costs in connection with the amendment and restatement of the Credit Agreement in September 2012 and approximately $0.1 million of additional deferred loan costs in connection with the borrowing base increase in December 2012. In connection with the March 2013 borrowing base redetermination, the Company incurred $0.3 million of additional deferred loan costs. These costs were included with the remaining unamortized balance of the deferred loan costs incurred previously. As a result, total deferred loan costs were $1.7 million at March 31, 2013, and these costs are being amortized over the term of the agreement, which approximates the amortization of these costs using the effective interest method. Between March 1, 2012 and December 31, 2012, the Company borrowed $150.0 million under the Credit Agreement to finance a portion of its working capital requirements and capital expenditures. At March 31, 2013, the Company had $205.0 million in borrowings outstanding under the Credit Agreement and approximately $1.3 million in outstanding letters of credit issued pursuant to the Credit Agreement. At March 31, 2013, the outstanding borrowings bore interest at an effective interest rate of approximately 3.6% per annum. Subsequent to March 31, 2013, the Company borrowed an additional $25.0 million to fund a portion of its working capital requirements and the acquisition of additional leasehold interests in Southeast New Mexico. At May 9, 2013, the Company had $230.0 million in borrowings outstanding under the Credit Agreement and approximately $1.3 million in outstanding letters of credit issued pursuant to the Credit Agreement.

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 prime rate for such day or (ii) the Federal Funds Effective Rate on such day, plus 0.50% or (iii) the daily adjusting LIBOR rate plus 1.0% plus, in each case, an amount from 0.75% to 2.25% 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 LIBOR rate by (B) a percentage equal to 100% minus the maximum rate during such interest calculation period at which RBC 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 1.75% to 3.25% 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 commitment fee of 0.375% to 0.50%, depending on the unused availability under the Credit Agreement, is also paid quarterly in arrears. The Company includes this commitment fee, any amortization of deferred financing costs (including origination, borrowing base increase and amendment fees) and annual agency fees as interest expense and 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, 2014 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, 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 its assets.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 4 - REVOLVING CREDIT AGREEMENT - Continued

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 amounts 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 March 31, 2013, the Company believes that it was in compliance with the terms of its Credit Agreement.

NOTE 5 - INCOME TAXES

The Company had a net loss for the three months ended March 31, 2013. Based upon its projections for the remainder of 2013, however, it anticipates incurring a small alternative minimum tax ("AMT") liability for the year ending December 31, 2013, the proportionate share of which is recorded as in the current income tax provision for the three months ended March 31, 2013. The Company established a valuation allowance at September 30, 2012 and retained a full valuation allowance of approximately $15.8 million at March 31, 2013 due to uncertainties regarding the future realization of its net deferred tax assets. As a result, there was no income tax expense or benefit recorded for the three months ended March 31, 2013, other than the AMT liability noted above. The Company had an effective income tax rate of 44.6% for the three months ended March 31, 2012. Total income tax expense for the three months ended March 31, 2012 differed from amounts computed by applying the U.S. statutory tax rates to income taxes due primarily to state taxes and the impact of an adjustment to the estimated permanent differences between book and taxable income related to stock compensation expense in prior periods.

NOTE 6 - STOCK-BASED COMPENSATION

In March 2013, the Company granted awards of options to purchase 507,500 and 284,292 shares of the Company's common stock at exercise prices of $8.21 per share and $8.18 per share, respectively, to certain of its employees. The fair value of these awards was approximately $2.8 million. The Company also granted awards of 324,771 shares of restricted stock to certain of its employees in March 2013. The fair value of these restricted stock awards was approximately $2.4 million. All of these awards vest over a term of three to four years.

In February 2013, options to purchase 408,000 shares of the Company's common stock at $10.00 per share expired unexercised or were forfeited.

NOTE 7 - DERIVATIVE FINANCIAL INSTRUMENTS

From time to time, the Company uses derivative financial instruments to mitigate its exposure to commodity price risk associated with oil, natural gas and natural gas liquids prices. These instruments consist of put and call options in the form of costless collars and swap contracts. The Company records derivative financial instruments in its consolidated balance sheet as either assets or liabilities 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. Comerica Bank, The Bank of Nova Scotia and RBC (or affiliates thereof) were the counterparties for our commodity derivatives at March 31, 2013. The Company has considered the credit standings of the counterparties in determining the fair value of its derivative financial instruments.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 7 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The Company has entered into various costless collar contracts to mitigate its exposure to fluctuations in oil prices, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss 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 one or more of these collars, the Company receives from the 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 one or more of these collars, the Company pays to the counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract oil volume.

The Company has also entered into various swap contracts to mitigate its exposure to fluctuations in oil prices, each with an established fixed price. For each calculation period, the specified price for determining the realized gain or loss 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 fixed price established by one or more of these swaps, the Company receives from the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract oil volume. When the settlement price is above the fixed price established by one or more of these swaps, the Company pays to the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract oil volume.

The Company has entered into various costless collar transactions for natural gas, 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 one or more of these collars, the Company receives from the 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 one or more of these collars, the Company pays to the counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract natural gas volume.

The Company has entered into various swap contracts to mitigate its exposure to fluctuations in natural gas liquids ("NGL") prices, each with an established fixed price. For each calculation period, the settlement price for determining the realized gain or loss to the Company pursuant to any of these transactions is the arithmetic average of any current month for delivery on the nearby month futures contracts of the underlying commodity as stated on the "Mont Belvieu Spot Gas Liquids Prices: NON-TET prop" on the pricing date. When the settlement price is below the fixed price established by one or more of these swaps, the Company receives from the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract NGL volume. When the settlement price is above the fixed price established by one or more of these swaps, the Company pays to the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract NGL volume.

At March 31, 2013, the Company had various 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 2013, 2014 and 2015.

At March 31, 2013, the Company had various swap contracts open and in place to mitigate its exposure to oil and NGL price volatility, each with a specific term (calculation period), notional quantity (volume hedged) and fixed price. Each contract is set to expire at varying times during 2013 and 2014.

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NOTE 7 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The following is a summary of the Company's open costless collar contracts for oil and natural gas and open swap contracts for oil and natural gas liquids at March 31, 2013.

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil	04/01/2013 - 12/31/2013	20,000	85.00	102.25	$ (140)
Oil	04/01/2013 - 12/31/2013	20,000	90.00	115.00	292
Oil	04/01/2013 - 12/31/2013	20,000	85.00	110.40	96
Oil	04/01/2013 - 12/31/2013	20,000	85.00	108.80	71
Oil	04/01/2013 - 06/30/2014	8,000	90.00	114.00	324
Oil	04/01/2013 - 06/30/2014	12,000	90.00	115.50	502
Oil	07/01/2013 - 12/31/2013	20,000	90.00	102.80	49
Oil	01/01/2014 - 12/31/2014	15,000	85.00	97.50	(122)
Oil	01/01/2014 - 12/31/2014	30,000	85.00	98.00	(179)
Oil	01/01/2014 - 12/31/2014	15,000	87.00	97.00	(41)
Oil	01/01/2014 - 12/31/2014	20,000	90.00	97.00	209
Oil	01/01/2014 - 12/31/2014	15,000	90.00	97.90	238
Oil	01/01/2014 - 12/31/2014	15,000	90.00	98.00	235
Total open oil costless collar contracts					1,534

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas	04/01/2013 - 07/31/2013	150,000	4.50	5.75	297
Natural Gas	04/01/2013 - 12/31/2013	100,000	3.00	3.83	(359)
Natural Gas	04/01/2013 - 12/31/2013	100,000	3.00	4.95	(46)
Natural Gas	04/01/2013 - 12/31/2013	100,000	3.00	4.96	(45)
Natural Gas	04/01/2013 - 12/31/2013	100,000	3.25	4.41	(114)
Natural Gas	04/01/2013 - 12/31/2013	100,000	3.25	4.44	(107)
Natural Gas	04/01/2013 - 12/31/2013	100,000	3.50	4.37	(100)
Natural Gas	07/01/2013 - 12/31/2013	150,000	3.00	4.24	(238)
Natural Gas	08/01/2013 - 12/31/2013	80,000	3.75	4.57	(15)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.00	5.15	(153)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.21	(89)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.22	(88)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.37	(68)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.42	(60)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.50	4.90	(94)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.75	4.77	(48)
Natural Gas	01/01/2015 - 12/31/2015	200,000	3.75	5.04	(51)
Total open natural gas costless collar contracts					(1,378)

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Fixed Price ($/Bbl)	Fair Value of Liability (thousands)
Oil	04/01/2013 - 12/31/2013	10,000	90.20	(591)
Oil	04/01/2013 - 12/31/2013	10,000	90.65	(551)
Total open oil swap contracts				(1,142)

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 7 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

Commodity	Calculation Period	Notional Quantity (Gal/month)	Fixed Price ($/Gal)	Fair Value of Asset (Liability) (thousands)
Purity Ethane	04/01/2013 - 12/31/2013	110,000	0.335	29
Purity Ethane	04/01/2013 - 12/31/2013	110,000	0.355	49
Propane	04/01/2013 - 12/31/2013	53,000	0.953	(5)
Propane	04/01/2013 - 12/31/2013	106,000	0.960	(5)
Propane	04/01/2013 - 12/31/2013	53,000	1.001	17
Propane	01/01/2014 - 12/31/2014	116,000	0.950	(4)
Normal Butane	04/01/2013 - 12/31/2013	14,700	1.455	2
Normal Butane	04/01/2013 - 12/31/2013	14,700	1.560	16
Normal Butane	04/01/2013 - 12/31/2013	21,000	1.575	26
Normal Butane	04/01/2013 - 12/31/2013	117,000	1.575	146
Normal Butane	01/01/2014 - 12/31/2014	17,500	1.540	25
Normal Butane	01/01/2014 - 12/31/2014	45,500	1.550	70
Isobutane	04/01/2013 - 12/31/2013	7,000	1.515	1
Isobutane	04/01/2013 - 12/31/2013	7,000	1.625	8
Isobutane	04/01/2013 - 12/31/2013	43,500	1.675	71
Isobutane	04/01/2013 - 12/31/2013	23,000	1.675	35
Isobutane	01/01/2014 - 12/31/2014	22,000	1.640	35
Isobutane	01/01/2014 - 12/31/2014	37,000	1.640	62
Natural Gasoline	04/01/2013 - 12/31/2013	12,000	2.025	(6)
Natural Gasoline	04/01/2013 - 12/31/2013	12,000	2.085	-
Natural Gasoline	04/01/2013 - 12/31/2013	12,000	2.102	2
Natural Gasoline	04/01/2013 - 12/31/2013	36,000	2.105	6
Natural Gasoline	04/01/2013 - 12/31/2013	90,500	2.148	45
Natural Gasoline	01/01/2014 - 12/31/2014	30,000	1.970	1
Natural Gasoline	01/01/2014 - 12/31/2014	41,000	2.000	14
Total open NGL swap contracts				640
Total open derivative financial instruments				$ (346)

These derivative financial instruments are subject to master netting arrangements within specific commodity types, i.e., oil, natural gas and natural gas liquids, by counterparty. Derivative financial instruments with Counterparty A are not subject to master netting across commodity types, while derivative financial instruments with Counterparties B and C do allow for cross-commodity master netting provided the settlement dates for the commodities are the same. The Company does not present different types of commodities with the same counterparty on a net basis in its consolidated balance sheet.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 7 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The following table presents the gross asset balances of the Company's derivative financial instruments, the amounts subject to master netting arrangements, the amounts that the Company has presented on a net basis and the location of these balances in its unaudited condensed consolidated balance sheet as of March 31, 2013 (in thousands).

Derivative Instruments	Gross amounts of recognized assets	Gross amounts netted in the consolidated balance sheet	Net amounts of assets presented in the consolidated balance sheet
Counterparty A			
Current assets	$ 2,677	$ (1,992)	$ 685
Other assets	3,990	(3,265)	725
Counterparty B			
Current assets	615	(402)	213
Other assets	2,132	(1,815)	317
Counterparty C			
Current assets	1,172	(928)	244
Other assets	1,999	(1,898)	101
Total	$ 12,585	$ (10,300)	$ 2,285

The following table presents the gross liability balances of the Company's derivative financial instruments, the amounts subject to master netting, the amounts that the Company has presented on a net basis and the location of these balances in its unaudited condensed consolidated balance sheet as of March 31, 2013 (in thousands).

Derivative Instruments	Gross amounts of recognized liabilities	Gross amounts netted in the consolidated balance sheet	Net amounts of liabilities presented in the consolidated balance sheet
Counterparty A			
Current liabilities	$ 2,055	$ (1,992)	$ 63
Long-term liabilities	3,265	(3,265)	-
Counterparty B			
Current liabilities	1,724	(402)	1,322
Long-term liabilities	1,952	(1,815)	137
Counterparty C			
Current liabilities	1,758	(928)	830
Long-term liabilities	2,177	(1,898)	279
Total	$ 12,931	$ (10,300)	$ 2,631

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 7 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The following table presents the gross asset balances of the Company's derivative financial instruments, the amounts subject to master netting, the amounts that the Company has presented on a net basis and the location of these balances in its unaudited condensed consolidated balance sheet as of December 31, 2012 (in thousands).

Derivative Instruments	Gross amounts of recognized assets	Gross amounts netted in the condensed consolidated balance sheet	Net amounts of assets presented in the condensed consolidated balance sheet
Counterparty A			
Current assets	$ 6,445	$ (2,373)	$ 4,072
Other assets	1,096	(370)	726
Counterparty B			
Current assets	530	(224)	306
Other assets	384	(339)	45
Total	$ 8,455	$ (3,306)	$ 5,149

The following table presents the gross liability balances of the Company's derivative financial instruments, the amounts subject to master netting, the amounts that the Company has presented on a net basis and the location of these balances in its unaudited condensed consolidated balance sheet as of December 31, 2012 (in thousands).

Derivative Instruments	Gross amounts of recognized liabilities	Gross amounts netted in the condensed consolidated balance sheet	Net amounts of liabilities presented in the condensed consolidated balance sheet
Counterparty A			
Current liabilities	$ 2,373	$ (2,373)	$ -
Long-term liabilities	370	(370)	-
Counterparty B			
Current liabilities	894	(224)	670
Long-term liabilities	339	(339)	-
Total	$ 3,976	$ (3,306)	$ 670

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).

Type of Instrument	Location in Condensed Consolidated Statement of Operations	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Derivative Instrument			
Oil	Revenues: Realized loss of derivatives	$ (237)	$ -
Natural Gas	Revenues: Realized gain on derivatives	524	3,063
NGL's	Revenues: Realized gain on derivatives	105	-
Realized gain on derivatives		392	3,063
Oil	Revenues: Unrealized loss on derivatives	(2,728)	(5,260)
Natural Gas	Revenues: Unrealized (loss) gain on derivatives	(2,511)	1,990
NGL's	Revenues: Unrealized gain on derivatives	414	-
Unrealized loss on derivatives		(4,825)	(3,270)
Total		$(4,433)	$ (207)

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 8 - 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 March 31, 2013 and December 31, 2012, the carrying values reported on the unaudited condensed consolidated balance sheets for cash, accounts receivable, prepaid expenses, accounts payable, accrued liabilities, royalties payable, advances from joint interest owners and other current liabilities approximate their fair values due to their short-term maturities and are classified at Level 1.

At March 31, 2013 and December 31, 2012, 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.

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 March 31, 2013 and December 31, 2012 (in thousands).

	Fair Value Measurements at March 31, 2013 using			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets (Liabilities)				
Certificates of deposit	$ -	$ 141	$ -	$ 141
Oil, natural gas and NGL derivatives	-	2,285	-	2,285
Oil, natural gas and NGL derivatives	-	(2,631)	-	(2,631)
Total	$ -	$ (205)	$ -	$ (205)

	Fair Value Measurements at December 31, 2012 using			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets (Liabilities)				
Certificates of deposit	$ -	$ 230	$ -	$ 230
Oil, natural gas and NGL derivatives	-	5,149	-	5,149
Oil, natural gas and NGL derivatives	-	(670)	-	(670)
Total	$ -	$ 4,709	$ -	$ 4,709

Additional disclosures related to derivative financial instruments are provided in Note 7. For purposes of fair value measurement, the Company determined that certificates of deposit and derivative financial instruments (e.g., oil, natural gas and NGL derivatives) should be classified at Level 2.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 8 - FAIR VALUE MEASUREMENTS - Continued

The Company accounts for additions to asset retirement obligations and lease and well equipment inventory when adjusted for impairment 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 March 31, 2013 and December 31, 2012 (in thousands).

	Fair Value Measurements at March 31, 2013 using			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets (Liabilities)				
Asset retirement obligations	$ -	$ -	$(656)	$(656)
Total	$ -	$ -	$(656)	$(656)

	Fair Value Measurements at December 31, 2012 using			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets (Liabilities)				
Asset retirement obligations	$ -	$ -	$(1,243)	$(1,243)
Lease and well equipment inventory	-	-	34	34
Total	$ -	$ -	$(1,209)	$(1,209)

For purposes of fair value measurement, the Company determined that additions and revisions to asset retirement obligations should be classified at Level 3. The Company recorded additions to asset retirement obligations of approximately $0.7 million for the three months ended March 31, 2013 and $1.2 million for the year ended December 31, 2012, respectively.

For purposes of fair value measurement, the Company determined that lease and well equipment inventory should be classified as Level 3 when adjusted for impairment. In 2012, the Company recorded an impairment to some of its equipment held in inventory consisting primarily of drilling rig parts of $425,000 and pipe and other equipment of $60,464; no impairment to any equipment was recorded for the three months ended March 31, 2013. 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 9 - COMMITMENTS AND CONTINGENCIES

Office Lease

The Company's corporate headquarters are located at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas. In January 2013, the Company entered into the fourth amendment to its office lease agreement. This amendment increased the square footage of its corporate headquarters by 7,782 square feet, thereby increasing the size of its corporate headquarters from 28,743 square feet to 36,525 square feet effective January 1, 2013. The lease expires on June 30, 2022.

Natural Gas and NGL Processing and Transportation Commitments

Effective September 1, 2012, the Company entered into a firm five-year natural gas processing and transportation agreement whereby the Company committed to transport the anticipated natural gas production from a significant portion of its Eagle Ford acreage in South Texas through the counterparty's system for processing at the counterparty's facilities. The agreement also includes firm transportation of the natural gas liquids extracted at the counterparty's processing plant downstream for fractionation. After processing, the residue natural gas is purchased by the counterparty at the tailgate of its processing plant and further transported under its firm natural gas transportation agreements. The arrangement contains fixed processing and liquids transportation and fractionation fees, and the revenue the Company receives varies with the quality of natural gas transported to the processing facilities and the contract period.

Under this agreement, if the Company does not meet 80% of the maximum thermal quantity transportation and processing commitments in a contract year, it will be required to pay a deficiency fee per MMBtu of natural gas deficiency. Any quantity in excess of the maximum MMBtu delivered in a contract year can be carried over to the next contract year for purposes of calculating the natural gas deficiency. The Company believes that its current and anticipated production from the wells covered by this agreement is sufficient to meet 80% of the maximum thermal quantity transportation and processing commitments under this agreement. The Company's remaining aggregate undiscounted minimum commitments under this agreement are $15.2 million at March 31, 2013. The Company paid approximately $0.3 million in processing and transportation fees under this agreement during the three months ended March 31, 2013.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

Other Commitments

At March 31, 2013, the Company was party to two drilling rig contracts to explore and develop its acreage in the Eagle Ford shale in South Texas. During the first quarter of 2013, the Company extended one of its drilling rig contracts for an additional six months. Drilling operations under this contract began in April 2013. The second contract is for a nine-month term and drilling operations under this contract began in December 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 rates being charged to the Company prior to the end of their respective contract terms, the Company would incur termination obligations. The Company's maximum outstanding aggregate termination obligations under these contracts were approximately $4.6 million at March 31, 2013. In April 2013, one of these rigs was moved to Southeast New Mexico to begin testing the Company's acreage position in the Delaware Basin.

During the first quarter of 2013, the Company agreed to participate in the drilling and completion of various non-operated wells in the Eagle Ford shale and the Haynesville shale. If all of these wells are drilled and completed, the Company will have minimum outstanding aggregate commitments for its participation in these wells of approximately $4.3 million at March 31, 2013, which it expects to incur within the next few months.

Legal Proceedings

Cynthia Fry Peironnet, et al. v. MRC Energy Company f/k/a 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.

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 rescission 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 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 the Company 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 Court of Appeal denied the Company's motion for rehearing, and the Company and certain other defendants filed an appeal with the Louisiana Supreme Court. The Louisiana Supreme Court granted the requests to hear an appeal of the Court of Appeal's decision, and the appeal was heard in March 2013. The decision of the Louisiana Supreme Court is pending at May 9, 2013.

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 $7 million.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 9 - COMMITMENTS AND CONTINGENCIES - Continued

MRC Energy Company f/k/a Matador Resources Company, v. Orca ICI Development, J.V. The Company and Orca, a non-operator working interest owner, have various disputes regarding certain of the Company's Eagle Ford shale wells and properties. Among other things, issues have arisen with respect to the rights and obligations of the Company and Orca under various agreements between the parties and Orca seeks the Company's consent to Orca's proposed assignment of its 50 percent working interest in the Cowey #3H and #4H wells to a non-industry person, despite the presence of a uniform maintenance of interest provision. On April 2, 2013, Orca brought suit against the Company in the 57th Judicial District Court of Bexar County, Texas and sought injunctive relief. The court denied Orca's demand for injunctive relief and on April 5, 2013, the Company moved to enforce arbitration provisions in the agreements between the parties. On April 22, 2013, the Company initiated an arbitration against Orca, seeking, among other things, a declaration that the Company may withhold its consent to Orca's putative assignment of these interests. On May 6, 2013, Orca and the Company agreed to resolve all outstanding issues between the parties regarding the respective rights and obligations of the parties under the agreements between them. In addition, Matador agreed to allow Orca time to try to resolve the outstanding issue with respect to Orca's purported assignment of its interest in the Cowey #3H and #4H wells and to stay the pending arbitration. If this issue is ultimately heard by an arbitration panel and the panel determines that the Company may withhold its consent to the assignment of the Cowey #3H and the Cowey #4H wells, Orca may be deemed a non-consent non-operator on these wells, and the Company will return $8.7 million submitted by Orca's putative assignee, $4.3 million of which was sent to the Company on April 18, 2013, subsequent to the end of the first quarter of 2013. All revenues generated by the production from these two wells, which were drilled but not completed at March 31, 2013, would then be attributable to the Company until such time as it has recovered 300% of the costs to drill, complete and equip the non-consent wells. Following the Company's recovery of this amount, Orca would be allowed to participate in the non-consent wells for its original working interest.

The Company is a defendant in several other lawsuits encountered in the ordinary course of its business. In the opinion of management, it is remote that these lawsuits will have a material adverse impact on the Company's financial position, results of operations or cash flows.

NOTE 10 - SUPPLEMENTAL DISCLOSURES

Accrued Liabilities

The following table summarizes the Company's current accrued liabilities at March 31, 2013 and December 31, 2012 (in thousands).

	March 31, 2013	December 31, 2012
Accrued evaluated and unproved and unevaluated property costs	$ 28,828	$ 45,592
Accrued support equipment and facilities costs	317	1,382
Accrued stock-based compensation	19	65
Accrued lease operating expenses	5,376	5,218
Accrued interest on borrowings under Credit Agreement	163	255
Accrued asset retirement obligations	760	660
Accrued partners' share of joint interest charges	2,299	3,597
Other	2,452	2,410
Total accrued liabilities	$ 40,214	$ 59,179

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 10 - SUPPLEMENTAL DISCLOSURES - Continued

Supplemental Cash Flow Information

The following table provides supplemental disclosures of cash flow information for the three months ended March 31, 2013 and 2012 (in thousands).

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Cash paid for interest expense, net of amounts capitalized	$ 1,359	$ 480
Asset retirement obligations related to mineral properties	626	125
Asset retirement obligations related to support equipment and facilities	30	28
(Decrease) increase in liabilities for oil and natural gas properties capital expenditures	(15,590)	13,681
(Decrease) increase in liabilities for support equipment and facilities	(1,065)	1099
(Decrease) increase in liabilities for accrued cost to issue equity	-	(67)
Issuance of restricted stock units for Board and advisor services	47	-
Issuance of common stock for advisor services	8	-
Stock-based compensation expense recognized as liability	30	(455)
Transfer of inventory from oil and natural gas properties	211	-

NOTE 11 - SUBSIDIARY GUARANTORS

Matador filed a registration statement on Form S-3 with the SEC, which became effective May 9, 2013, and registered, among other securities, debt securities. The subsidiaries of Matador (the “Subsidiaries”) are co-registrants with Matador, and the registration statement registers guarantees of debt securities by the Subsidiaries. As of March 31, 2013, the Subsidiaries are 100 percent owned by Matador and any guarantees by the Subsidiaries will be full and unconditional (except for customary release provisions). Matador has no assets or operations independent of the Subsidiaries, and there are no significant restrictions upon the ability of the Subsidiaries to distribute funds to Matador. In the event that more than one of the Subsidiaries provide guarantees of any debt securities issued by Matador, such guarantees will constitute joint and several obligations.

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

The following discussion and analysis of our financial condition and results of operations 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, 2012 filed with the SEC (the "Annual Report"), along with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in the Annual Report. 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 the "Risk Factors" section of the Annual Report and 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 (the "Quarterly Report"), references to "we," "our" or "the Company" refer to Matador Resources Company and its subsidiaries as a whole and references to Matador refer solely 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 the Annual Report.

Cautionary Note Regarding Forward-Looking Statements

Certain statements in this Quarterly Report 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 success of our drilling program, 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 Quarterly 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;
- 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;
- 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 the Annual Report.

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, including the securities laws of the United States and the rules and regulations of the SEC.

Overview

Matador Resources Company is 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 focused primarily on the oil and liquids rich portion of the Eagle Ford shale play in South Texas and the Wolfcamp and Bone Spring plays in Southeast New Mexico and West Texas. We also operate in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. The Company also has a large exploratory leasehold position in Southwest Wyoming and adjacent areas of Utah and Idaho where we are testing the Meade Peak shale.

Our business success and financial results are dependent on many factors beyond our control, such as economic, political and regulatory developments, as well as competition from other sources of energy. Commodity price volatility, in particular, is a significant risk factor for us. Commodity prices are affected by changes in market supply and demand, which are impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, oil and natural gas price differentials and other factors. Prices for oil, natural gas and natural gas liquids will affect the cash flows available to us for capital expenditures and our ability to borrow and raise additional capital. Declines in oil, natural gas or natural gas liquids prices would not only reduce our revenues, but could also reduce the amount of oil, natural gas or natural gas liquids that we can produce economically, and as a result, could have an adverse effect on our financial condition, results of operations, cash flows, reserves and borrowing base under our Credit Agreement.

During the first quarter of 2013, our operations were primarily focused on the exploration and development of our Eagle Ford shale properties in South Texas. During the three months ended March 31, 2013, we completed and began producing oil and natural gas from 4 gross/4.0 net operated Eagle Ford shale wells. At March 31, 2013, we had also drilled three Eagle Ford wells from the same pad on our Cowey lease in DeWitt County and were in the process of drilling three Eagle Ford wells from the same pad on our Martin Ranch lease in LaSalle County. We expect that each group of three wells will be completed using zipper style, hydraulic fracturing operations during the second quarter of 2013. At March 31, 2013, we had also drilled and were preparing to complete one additional well on our Martin Ranch lease which we expect to complete during the second quarter of 2013. For the three months ended March 31, 2013, we also participated in two non-operated Haynesville shale wells in Northwest Louisiana (both less than 1% working interest) and one non-operated test of the Buda formation in South Texas (approximately 21% working interest).

We had two contracted drilling rigs operating in South Texas throughout the first quarter of 2013, and all of our operated drilling and completion activities were focused on the Eagle Ford shale. In mid-April 2013, we moved one of our contracted drilling rigs to Lea County, New Mexico to begin a three-well exploration program testing portions of our leasehold position in the Delaware Basin in Southeast New Mexico and West Texas. While this rig is operating in Southeast New Mexico and West Texas, we will have only one contracted rig operating in the Eagle Ford shale in South Texas. At May 9, 2013, we continued to have one contracted drilling rig operating in Karnes County in South Texas and one contracted drilling rig operating in Lea County in Southeast New Mexico.

During the first quarter of 2013, our oil production was approximately 460,000 Bbl, an increase of 130%, as compared to approximately 200,000 Bbl of oil produced during the first quarter of 2012. Our average daily oil equivalent production for the three months ended March 31, 2013 was approximately 10,900 BOE per day, including approximately 5,100 Bbl of oil per day and 34.7 MMcf of natural gas per day, as compared to approximately 8,000 BOE per day, including approximately 2,200 Bbl of oil per day and 34.9 MMcfe per day, for the three months ended March 31, 2012. Both the average daily oil equivalent production and the average daily oil production for the first quarter of 2013 were the best quarterly figures in our Company's history. Oil production comprised approximately 47% of our total production (using a conversion ratio of one Bbl of oil per six Mcf of natural gas) during the first quarter of 2013, as compared to approximately 27% of our total production during the first quarter of 2012. Our oil production of 460,000 Bbl for the three months ended March 31, 2013 was also a sequential increase of 8% from 426,000 Bbl of oil produced during the three months ended December 31, 2012.

For the three months ended March 31, 2013, our oil and natural gas revenues were $59.3 million, more than double our oil and natural gas revenues of $29.2 million for the three months ended March 31, 2012. Our oil revenues increased 126% to $48.7 million during the first quarter of 2013, as compared to oil revenues of $21.5 million during the first quarter of 2012. Our natural gas revenues increased 40% to $10.6 million for the three months ended March 31, 2013, as compared to natural gas revenues of $7.6 million during the three months ended March 31, 2012. Our Adjusted EBITDA for the first quarter of 2013 was $40.7 million, an increase of 91% from an Adjusted EBITDA of $21.3 million reported for the first quarter of 2012, and a sequential increase of 7% from an Adjusted EBITDA of $38.0 million reported for the fourth quarter of 2012.

We realized a weighted average oil price of $105.72 per Bbl for the three months ended March 31, 2013, which represented an uplift of $10.00 per Bbl to $12.00 per Bbl compared to NYMEX West Texas Intermediate oil prices during the first quarter of 2013. Most of our Eagle Ford oil production in South Texas is sold based on a Louisiana Light Sweet oil price index less transportation costs. During the first quarter of 2013, the differential between Louisiana Light Sweet and West Texas Intermediate oil prices was close to $20.00 per Bbl at times. Subsequent to March 31, 2013, the price differential between these two benchmark prices has begun to narrow, and as a result, we may not realize similar uplifts to West Texas Intermediate oil prices in future periods.

At March 31, 2013, our estimated total proved oil and natural gas reserves were 23.6 million BOE, including 10.7 million Bbl of oil and 77.5 Bcf of natural gas (12.9 million BOE), with a PV-10 of $438.1 million and a Standardized Measure of $407.0 million. Our total proved reserves remained relatively flat compared to the 23.8 million BOE of total proved reserves reported at December 31, 2012, including 10.5 million Bbl of oil and 80.0 Bcf of natural gas (13.3 million BOE). This is primarily due to oil and natural gas production of approximately 1.0 million BOE during the first quarter of 2013 and to the fact that the oil and natural gas reserves associated with three of the four Eagle Ford shale wells that we completed and placed on production during the first quarter of 2013 were previously included as proved undeveloped reserves in our estimated total proved reserves at December 31, 2012. Our proved developed oil reserves increased to 5.4 million Bbl at March 31, 2013, as compared to 4.8 million Bbl at December 31, 2012, and have doubled when compared to proved developed oil reserves at March 31, 2012, which were 2.7 million Bbl. At March 31, 2013, approximately 60% of our total proved reserves were proved developed reserves, 45% of our total proved reserves were oil and 55% of our total proved reserves were natural gas. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

Effective May 8, 2013, we increased our capital expenditure budget for 2013 from $310.0 million to $325.0 million, as we anticipate the acquisition of additional leasehold interests throughout 2013, particularly in Southeast New Mexico and West Texas. We also plan to maintain leasing efforts in the Eagle Ford play and the Haynesville play as opportunities arise. We intend to allocate 78% of our updated capital expenditure budget of $325.0 million to the exploration, development and acquisition of additional interests in South Texas, primarily in the Eagle Ford shale play. We also plan to allocate about 20% of our 2013 capital expenditure budget to the exploration and acquisition of additional interests in the Wolfcamp, Bone Spring and other oil and liquids-rich plays in Southeast New Mexico and West Texas. As a result of these anticipated capital expenditures in South Texas, Southeast New Mexico and West Texas, we plan to allocate approximately 98% of our 2013 anticipated capital expenditure budget to opportunities prospective for oil and liquids production. While we have budgeted capital expenditures of $325.0 million for 2013, the aggregate amount of capital we will expend may fluctuate materially based on market conditions, the actual costs to drill scheduled wells, our drilling results and our ability to obtain additional capital.

In March and April 2013, we acquired an additional 14,700 gross and 12,500 net acres in Lea and Eddy Counties, New Mexico. Including these recent acreage acquisitions, at May 9, 2013, our total acreage position in Southeast New Mexico and West Texas is approximately 30,600 gross and 20,200 net acres, of which we consider approximately 22,900 gross and 18,100 net acres to be prospective for multiple oil and liquids rich targets, including the Wolfcamp and Bone Spring plays. We expect to continue adding to our leasehold position in Southeast New Mexico and West Texas throughout the remainder of 2013, subject to the availability of our capital resources. Through March 31, 2013, we had spent approximately 21% of our 2013 capital expenditure budget of $325.0 million.

As we continue to explore and develop our leasehold positions in the Eagle Ford shale in South Texas and as we begin to explore and develop our leasehold positions in the Wolfcamp, Bone Spring and other plays in Southeast New Mexico and West Texas, we may face various challenges in establishing operations in new areas, including securing the necessary services to drill and complete wells and securing the necessary facilities to gather, process, transport and market the oil and natural gas that we produce. We may also incur higher than anticipated costs associated with establishing new operating infrastructure on our leases throughout these areas, as we have experienced at times in South Texas. We believe that 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, in particular, hydraulic fracturing services for our newly drilled wells during the three months ended March 31, 2013 or during the year ended December 31, 2012, although we experienced these problems at various times during 2011 in South Texas and may have such difficulties again in the future. At May 9, 2013, we have just initiated our drilling operations in Southeast New Mexico. We believe that maintaining reliable and timely drilling and completion services and reducing drilling and completion costs will be essential to the successful development and profitability of the Eagle Ford shale play, as well as the Wolfcamp, Bone Spring and other plays in Southeast New Mexico and West Texas.

We did not experience any significant pipeline interruptions in South Texas during the three months ended March 31, 2013, although we experienced temporary pipeline interruptions from time to time during the year ended December 31, 2012 associated with natural gas production from our Eagle Ford shale wells. To alleviate most of the interruptions and processing capacity constraints we experienced during 2012, effective September 1, 2012, we entered into a firm five-year natural gas processing and transportation agreement whereby we committed to transport the anticipated natural gas production from a significant portion of our Eagle Ford acreage in South Texas through the counterparty's system for processing at the counterparty's facilities. The agreement also includes firm transportation of the natural gas liquids extracted at the counterparty's processing plant downstream for fractionation. No assurance can be made that this agreement will alleviate these issues completely, and if we were required to shut in our production for long periods of time due to pipeline interruptions or lack of processing facilities or capacity of these facilities, it would have a material adverse effect on our business, financial condition, results of operations and cash flows. We may experience similar interruptions and processing capacity constraints as we begin to explore and develop our leasehold position in Southeast New Mexico and West Texas in 2013.

Estimated Proved Reserves

The following table sets forth our estimated total proved oil and natural gas reserves at March 31, 2013, December 31, 2012 and March 31, 2012. Our production and proved reserves are reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where we produce liquids-rich natural gas, such as in the Eagle Ford shale in South Texas, the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines 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 oil and natural gas 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 proved reserves are estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

	March 31, 2013 (1)	December 31, 2012 (1)	March 31, 2012 (1)
Estimated Proved Reserves Data:[2]			
Estimated proved reserves:			
Oil (MBbl)	10,712	10,485	5,738
Natural Gas (Bcf)	77.5	80.0	168.7[3]
Total (MBOE) [4]	23,626	23,819	33,855
Estimated proved developed reserves:			
Oil (MBbl)	5,374	4,764	2,678
Natural Gas (Bcf)	52.2	54.0	56.1
Total (MBOE) [4]	14,070	13,771	12,028
Percent developed	59.6%	57.8%	35.5%
Estimated proved undeveloped reserves:			
Oil (MBbl)	5,338	5,721	3,060
Natural Gas (Bcf)	25.3	26.0	112.6[3]
Total (MBOE) [4]	9,556	10,048	21,827
PV-10[5] (in millions)	$ 438.1	$ 423.2	$ 329.6
Standardized Measure[6] (in millions)	$ 407.0	$ 394.6	$ 287.4

(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 April 2012 to March 2013 were $89.17 per Bbl for oil and $2.950 per MMBtu for natural gas, for the period January 2012 through December 2012 were $91.21 per Bbl for oil and $2.757 per MMBtu for natural gas and for the period April 2011 to March 2012 were $94.65 per Bbl for oil and $3.731 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. We report our proved reserves in two streams, oil and natural gas, and the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold.

(3) Subsequent to March 31, 2012, as a result of substantially lower natural gas prices in 2012, at June 30, 2012, we removed 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana from our total proved reserves, most of which were attributable to non-operated properties.

(4) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(5) 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 March 31, 2013 and December 31, 2012 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 March 31, 2013, December 31, 2012 and March 31, 2012 were, in millions, $31.1, $28.6 and $42.2, respectively.

(6) 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.

At March 31, 2013, our estimated total proved oil and natural gas reserves were 23.6 million BOE, including 10.7 million Bbl of oil and 77.5 Bcf of natural gas (12.9 million BOE), with a PV-10 of $438.1 million and a Standardized Measure of $407.0 million. Our total proved reserves remained relatively flat compared to the 23.8 million BOE of total proved reserves reported at December 31, 2012, including 10.5 million Bbl of oil and 80.0 Bcf of natural gas (13.3 million BOE). This is primarily due to oil and natural gas production of approximately 1.0 million BOE during the first quarter of 2013 and to the fact that three of the four wells we completed and placed on production in the Eagle Ford shale during the first quarter of 2013 were previously included as proved undeveloped reserves in our total proved reserves at December 31, 2012. At March 31, 2013, approximately 60% of our total proved reserves were proved developed reserves, 45% of our total proved reserves were oil and 55% of our total proved reserves were natural gas. At March 31, 2012, approximately 36% of our total proved reserves were proved developed reserves, 17% of our total proved reserves were oil and 83% of our total proved reserves were natural gas. Our proved developed oil reserves increased by 13% to 5.4 million Bbl at March 31, 2013, as compared to 4.8 million Bbl at December 31, 2012, and have doubled when compared to proved developed oil reserves at March 31, 2012, which were 2.7 million Bbl. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

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 the Annual Report.

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Critical Accounting Policies

There have been no changes to our critical accounting policies and estimates from those set forth in the Annual Report.

Recent Accounting Pronouncements

There have been no additional recent accounting pronouncements impacting our financial reporting from those set forth in the Annual Report.

Results of Operations

Revenues

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

	Three Months Ended March 31, 2013 (Unaudited)	Three Months Ended March 31, 2012 (Unaudited)
Operating Data:		
Revenues (in thousands): (1)		
Oil	$ 48,670	$ 21,547
Natural gas	10,649	7,617
Total oil and natural gas revenues	59,319	29,164
Realized gain on derivatives	392	3,063
Unrealized loss on derivatives	(4,825)	(3,270)
Total revenues	$ 54,886	$ 28,957
Net Production Volumes: (1)		
Oil (MBbl)	460	200
Natural gas (Bcf)	3.1	3.2
Total oil equivalent (MBOE)(2)	981	730
Average daily production (BOE/d)(2)	10,897	8,023
Average Sales Prices:		
Oil, with realized derivatives (per Bbl)	$ 105.20	$ 107.57
Oil, without realized derivatives (per Bbl)	$ 105.72	$ 107.57
Natural gas, with realized derivatives (per Mcf)	$ 3.61	$ 3.36
Natural gas, without realized derivatives (per Mcf)	$ 3.41	$ 2.40

(1) We report our production volumes in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Revenues associated with extracted natural gas liquids are included with our natural gas revenues.

(2) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012

Oil and natural gas revenues. Our oil and natural gas revenues increased by approximately $30.2 million to approximately $59.3 million, or an increase of about 103% for the three months ended March 31, 2013, as compared to the three months ended March 31, 2012. This increase in oil and natural gas revenues includes an increase in our oil revenues of $27.1 million and an increase in our natural gas revenues of $3.0 million for the three months ended March 31, 2013, as compared to the comparable period in 2012. Our oil revenues increased by 126% to $48.7 million for the three months ended March 31, 2013, as compared to $21.5 million for the three months ended March 31, 2012. This increase in oil revenues reflects the increase in our oil production by 130% to 460,000 Bbl of oil in the first quarter of 2013, or about 5,100 Bbl of oil per day, as compared to approximately 200,000 Bbl of oil produced, or about 2,200 Bbl of oil per day, in the first quarter of 2012. This increase in oil production is attributable to our drilling operations in the Eagle Ford shale. The weighted average oil price of $105.72 per Bbl that we realized for the three months ended March 31, 2013 was comparable to, but slightly less than, the weighted average oil price of $107.57 that we realized for the three months ended March 31, 2012. The increase in natural gas revenues on relatively flat natural gas production between the respective periods resulted primarily from a higher weighted average natural gas price of $3.41 per Mcf realized during the first quarter of 2013, as compared to a weighted average natural gas price of $2.40 per Mcf realized during the first quarter of 2012.

Realized gain (loss) on derivatives. Our realized gain on derivatives decreased by approximately $2.7 million to $0.4 million for the three months ended March 31, 2013, as compared to $3.1 million for the three months ended March 31, 2012. For the three months ended March 31, 2013, we realized a net gain of approximately $0.5 million and $0.1 million attributable to our natural gas and NGL derivative contracts, respectively, and we realized a net loss of approximately $0.2 million attributable to our oil derivative contracts. For the three months ended March 31, 2012, all of the realized gain was attributable to our natural gas derivative contracts. The decreased gain on derivatives realized from our open natural gas costless collar contracts during the respective periods resulted from higher natural gas prices during the three months ended March 31, 2013, as compared to the three months ended March 31, 2012. We realized approximately $0.39 per MMBtu hedged on all of our open natural gas costless collar contracts during the three months ended March 31, 2013, as compared to $1.70 per MMBtu hedged on all of our open natural gas costless collar contracts during the three months ended March 31, 2012. Our total natural gas volumes hedged for the three months ended March 31, 2013 were also approximately 25% less than the total natural gas volumes hedged for the same period in 2012. In addition, during the first quarter of 2013, our open natural gas costless collars had average floor and ceiling prices of $3.50 per MMBtu and $4.97 per MMBtu, respectively, compared to $4.44 per MMBtu and $5.78 per MMBtu, respectively, during the first quarter of 2012. We had no realized gain or loss associated with our open oil derivative contracts during the three months ended March 31, 2012. We had no open NGL derivative contracts during the three months ended March 31, 2012.

Unrealized gain (loss) on derivatives. Our unrealized loss on derivatives was approximately $4.8 million for the three months ended March 31, 2013, as compared to an unrealized loss of approximately $3.3 million for the three months ended March 31, 2012. During the period from December 31, 2012 to March 31, 2013, the net fair value of our open oil, natural gas and NGL derivative contracts decreased from approximately $4.5 million to approximately $(0.3) million, resulting in an unrealized loss on derivatives of approximately $4.8 million for the three months ended March 31, 2013. This decrease in the net fair value of our open oil, natural gas and NGL contracts for the three months ended March 31, 2013 was due primarily to an increase in oil and natural gas prices during the three months ended March 31, 2013 that reduced the fair value of our open oil and natural gas contracts, partially offset by a decrease in certain NGL prices that increased the fair value of our open NGL derivative contracts. During the period from December 31, 2011 to March 31, 2012, the net fair value of our open oil and natural gas derivative contracts decreased from $9.3 million to $6.0 million, resulting in an unrealized loss on derivatives of $3.3 million for the three months ended March 31, 2012. We had no open NGL contracts during the three months ended March 31, 2012.

Expenses

The following table summarizes our operating expenses and other income (expense) for the periods indicated:

	Three Months Ended March 31,	
(In thousands, except expenses per BOE)	2013 (Unaudited)	2012 (Unaudited)
Expenses:		
Production taxes and marketing	$ 4,097	$ 2,165
Lease operating	10,899	4,645
Depletion, depreciation and amortization	28,232	11,205
Accretion of asset retirement obligations	81	53
Full-cost ceiling impairment	21,230	-
General and administrative	4,602	3,789
Total expenses	69,141	21,857
Operating income (loss)	(14,255)	7,100
Other income (expense):		
Interest expense	(1,271)	(308)
Interest and other income	67	73
Total other expense	(1,204)	(235)
Income (loss) before income taxes	(15,459)	6,865
Total income tax provision	46	3,064
Net income (loss)	$ (15,505)	$ 3,801
Expenses per BOE:		
Production taxes and marketing	$ 4.18	$ 2.96
Lease operating	$ 11.11	$ 6.36
Depletion, depreciation and amortization	$ 28.79	$ 15.35
General and administrative	$ 4.69	$ 5.19

Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012

Production taxes and marketing. Our production taxes and marketing expenses increased by approximately $1.9 million to approximately $4.1 million, or an increase of approximately 89%, for the three months ended March 31, 2013, as compared to $2.2 million for the three months ended March 31, 2012. The increase in our production taxes and marketing expenses was primarily due to the increase in our oil and natural gas revenues by approximately 103% during the three months ended March 31, 2013, as compared to the three months ended March 31, 2012. The majority of this increase was attributable to production taxes associated with the large increase in oil production and associated oil revenues during the period ended March 31, 2013 resulting from our drilling operations in the Eagle Ford shale in South Texas. Our total production was comprised of approximately 47% oil and 53% natural gas for the three months ended March 31, 2013, as compared to approximately 27% oil and 73% natural gas during the same period in 2012. On a unit-of-production basis, our production taxes and marketing expenses increased by 41% to $4.18 per BOE for the three months ended March 31, 2013, as compared to $2.96 per BOE for the three months ended March 31, 2012.

Lease operating expenses. Our lease operating expenses increased by approximately $6.3 million to approximately $10.9 million, or an increase of almost 135%, for the three months ended March 31, 2013, as compared to the three months ended March 31, 2012. During these respective periods, our total oil and natural gas production increased about 34% to 981,000 BOE from 730,000 BOE, including an increase in oil production of 130% to approximately 460,000 Bbl of oil from approximately 200,000 Bbl of oil. Our lease operating expenses per unit of production increased approximately 75% to $11.11 per BOE for the three months ended March 31, 2013, as compared to $6.36 per BOE for the three months ended March 31, 2012. This increase in lease operating expenses was primarily attributable to the overall increase in oil production between the comparable periods, as well as to the increased percentage of oil being produced, which was 47% of total production by volume in the first quarter of 2013, compared to only 27% of total production by volume in the first quarter of 2012. In addition, we continued to use temporary rental test equipment for flowback of production following completion on certain of our properties during the three months ended March 31, 2013 while permanent production facilities were being installed and tested. This rental test equipment was monitored by 24-hour contract personnel, resulting in higher operating costs during the three months ended March 31, 2013 than we anticipate going forward now that the permanent production facilities on those properties are completed and operational. We estimate that approximately $2.50 per BOE of our lease operating expenses for the quarter ended March 31, 2013 was directly attributable to these extended flowback operations. At March 31, 2013 and at May 9, 2013, we had no rental flowback equipment operating on any of our Eagle Ford properties in South Texas.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $17.0 million to $28.2 million, or an increase of about 152%, for the three months ended March 31, 2013, as compared to the three months ended March 31, 2012. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased to $28.79 per BOE for the three months ended March 31, 2013, or an increase of about 88%, from $15.35 per BOE for the three months ended March 31, 2012. This increase in our depletion, depreciation and amortization expenses was attributable to the increase of approximately 34% in our total oil and natural gas production to 981,000 BOE from 730,000 BOE during the respective periods, as well as to the higher drilling and completion 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 $28,000 to approximately $81,000, or an increase of about 53%, for the three months ended March 31, 2013, as compared to the three months ended March 31, 2012. 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. During the quarter ended March 31, 2013, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $13.7 million. As a result, we recorded an impairment charge of $21.2 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $7.5 million. At March 31, 2013 we retained a full valuation allowance against our net deferred tax assets, and as a result, the income tax benefit of $7.5 million is not reflected in the unaudited condensed consolidated statement of operations for the three months ended March 31, 2013. The full-cost ceiling impairment resulted primarily from the continued low weighted average index price for natural gas used to estimate total proved reserves at March 31, 2013 which was $2.95 per MMBtu for the period April 2012 through March 2013. No impairment to the net carrying value of our oil and natural gas properties on the unaudited condensed consolidated balance sheet resulting from a full-cost ceiling impairment was recorded at March 31, 2012.

General and administrative. Our general and administrative expenses increased by $0.8 million to $4.6 million, or an increase of about 21%, for the three months ended March 31, 2013, as compared to $3.8 million for the three months ended March 31, 2012. Our general and administrative expenses decreased by approximately 10% on a unit-of-production basis to $4.69 per BOE for the three months ended March 31, 2013, as compared to $5.19 per BOE for the three months ended March 31, 2012. The increase in our general and administrative expenses was primarily attributable to an increase in stock-based compensation costs of $0.9 million for the three months ended March 31, 2013, as compared to the three months ended March 31, 2012.

Interest expense. For the three months ended March 31, 2013, we incurred total interest expense of approximately $1.6 million. We capitalized approximately $0.3 million of our interest expense on certain qualifying projects for the three months ended March 31, 2013 and expensed the remaining $1.3 million to operations. For the three months ended March 31, 2012, we incurred total interest expense of approximately $0.6 million. We capitalized approximately $0.3 million of our interest expense on certain qualifying projects for the three months ended March 31, 2012 and expensed the remaining $0.3 million to operations. As we increase the borrowings under our Credit Agreement, we expect to incur increased interest expense.

Interest and other income. Our interest and other income decreased by approximately $6,000 to approximately $67,000, or a decrease of about 8%, for the three months ended March 31, 2013, as compared to the three months ended March 31, 2012. The decrease in our interest and other income was due primarily to slight decreases in both the transportation income we received and in the salt water disposal income we received from third parties during the first quarter of 2013 as compared to the first quarter of 2012, although on the whole, this item is an insignificant component of our overall income. Our cash and certificates of deposit increased to approximately $4.8 million at March 31, 2013 from approximately $3.1 million at March 31, 2012.

Total income tax provision. Although we had a net loss for the three months ended March 31, 2013, based on our projections for the remainder of 2013, we anticipate incurring a small alternative minimum tax (“AMT”) liability for the year ending December 31, 2013, the proportionate share of which is recorded as the current income tax provision of $46,000 for the three months ended March 31, 2013. The total income tax provision for the three months ended March 31, 2013 represents only our estimate of the AMT liability attributable to the three months ended March 31, 2013, while the income tax provision recorded at March 31, 2012 reflected only deferred income taxes. The Company established a valuation allowance at September 30, 2012 and retained a full valuation allowance of approximately $15.8 million at March 31, 2013 due to uncertainties regarding the future realization of its net deferred tax assets. As a result, there was no income tax expense or benefit recorded for the three months ended March 31, 2013, other than the AMT liability noted above. We had an effective income tax rate of 44.6% for the three months ended March 31, 2012. Total income tax expense for the three months ended March 31, 2012 differed from amounts computed by applying the U.S. statutory tax rates to income taxes due primarily to state taxes and the impact of an adjustment to the estimated permanent differences between book and taxable income related to stock compensation expense in prior periods.

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 2013 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 ventures, 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 and to continue to grow our operating cash flows.

At March 31, 2013, we had cash and certificates of deposits totaling approximately $4.8 million, the borrowing base under our Credit Agreement was $255.0 million and we had $205.0 million of outstanding long-term borrowings and approximately $1.3 million in outstanding letters of credit. These borrowings bore interest at an effective interest rate of 3.6% per annum. From April 1, 2013 through May 9, 2013, we borrowed an additional $25.0 million under our Credit Agreement to finance a portion of our working capital requirements and capital expenditures and the acquisition of additional leasehold interests in Southeast New Mexico. At May 9, 2013, we had cash and certificates of deposit totaling approximately $11.3 million, $230.0 million of outstanding long-term borrowings and approximately $1.3 million in outstanding letters of credit under our Credit Agreement.

On September 28, 2012, we entered into the third amended and restated Credit Agreement, which increased the maximum facility amount to $500.0 million from $400.0 million and increased the borrowing base to $200.0 million from $125.0 milllion as a result of our lenders’ review of our proved oil and natural gas reserves at June 30, 2012. The borrowing base under the Credit Agreement is scheduled to be redetermined automatically on May 1 and November 1 by the lenders based primarily on the estimated value of our proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. Both we and the lenders may each request an unscheduled redetermination of the borrowing base once between scheduled redetermination dates. During the fourth quarter of 2012, we requested one such unscheduled redetermination, and on December 20, 2012, the borrowing base was increased from $200.0 million to $215.0 million as a result of our lenders’ review of our proved oil and natural gas reserves at September 30, 2012. In addition, during the first quarter of 2013, our lenders completed their review of our proved oil and natural gas reserves at December 31, 2012, and as a result, on March 11, 2013, the borrowing base under our Credit Agreement was increased to $255.0 million. This most recent redetermination constitutes the regularly scheduled May 1 redetermination. In late April 2013, we requested an unscheduled redetermination of the borrowing base and expect to request additional redeterminations between each scheduled redetermination date during 2013, which we believe should result in approximately quarterly increases in the borrowing base under our Credit Agreement throughout 2013. We expect these additional increases to the borrowing base will be primarily as a result of anticipated increases in our proved oil and natural gas reserves, and particularly our proved developed oil and natural gas reserves. As a result of these anticipated increases in the borrowing base, together with our anticipated increases in oil production and related revenues, we expect to have sufficient cash flows from operations and future borrowing capacity under our Credit Agreement to fund our capital expenditure requirements for 2013. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and natural gas liquids prices and to partially offset reductions in our cash flows from operations resulting from declines in commodity prices. However, should our drilling activities be less successful than we anticipate or result in less growth in our proved oil and natural gas reserves or less cash flows than we anticipate in 2013, or should oil prices decline substantially, we may require additional sources of financing, including through additional borrowings under our Credit Agreement or additional credit arrangements, potential joint ventures and potential issuances of equity or debt securities, which may not be available on terms reasonably acceptable to us or at all. To the extent such sources of financing are not available on terms reasonably acceptable to us, we may need to reduce our capital spending and rate of growth.

Although a majority of our anticipated increase in cash flows from operations during the year ending December 31, 2013, as compared to our cash flows from operations in prior periods, is expected to come from development activities on proved properties in the Eagle Ford shale play at December 31, 2012, these development activities may be less successful than we anticipate. Further, a portion of our anticipated increase in cash flows from operations during the year ending December 31, 2013 is expected to come from exploration activities on currently unproved properties in the Eagle Ford shale in South Texas and in the Wolfcamp and Bone Spring plays in Southeast New Mexico and West Texas, and these exploration activities may not be as successful as we anticipate. Additionally, any anticipated increases in our cash flows from operations are based upon current expectations of oil and natural gas prices for 2013 and the hedges we currently have in place. If our exploration and development activities result in less cash flows than anticipated, we may seek additional sources of capital, including through additional borrowings under our Credit Agreement (assuming availability under our borrowing base), the establishment of additional credit arrangements, the sale of equity or debt securities, the sale of assets or acreage or entering into one or more joint ventures, none of which may be available on terms acceptable to us or at all. In addition to future borrowings under our Credit Agreement, we may also seek to raise 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 markets or otherwise. It is likely that any such sales would dilute the ownership interest of our existing shareholders. There is no guarantee that we would be able to sell such debt or equity securities on terms acceptable to us or at all. It is also possible that, to the extent we are not able to obtain additional sources of capital, we may modify our planned capital expenditure budget for 2013 accordingly. Exploration and development 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.

Our cash flows for the three months ended March 31, 2013 and 2012 are presented below:

	Three Months Ended March 31,	
(In thousands)	**2013 (Unaudited)**	**2012 (Unaudited)**
Net cash provided by operating activities	$ 32,229	$ 5,110
Net cash used in investing activities	(84,672)	(52,764)
Net cash provided by financing activities	55,000	39,744
Net change in cash	$ 2,557	$ (7,910)
Adjusted EBITDA[(1)]	$ 40,672	$ 21,338

(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 $27.1 million to $32.2 million for the three months ended March 31, 2013, as compared to net cash provided by operating activities of $5.1 million for the three months ended March 31, 2012. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased significantly to $39.4 million for the three months ended March 31, 2013 from $21.0 million for the three months ended March 31, 2012. This increase is primarily attributable to the 130% increase in our oil production to approximately 460,000 Bbl from approximately 200,000 Bbl during the respective periods as a result of our ongoing operations in the Eagle Ford shale. Changes in our operating assets and liabilities between March 31, 2012 and March 31, 2013 also resulted in a net increase of approximately $8.8 million in net cash provided by operating activities for the three months ended March 31, 2013, as compared to the three months ended March 31, 2012.

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. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and natural gas liquids prices. In addition, we attempt to avoid long-term service agreements in order to minimize ongoing future commitments.

Cash Flows Used in Investing Activities

Net cash used in investing activities increased by approximately $31.9 million to $84.7 million for the three months ended March 31, 2013 from $52.8 million for the three months ended March 31, 2012. This increase in net cash used in investing activities is almost entirely attributable to the increase in cash used for oil and natural gas properties capital expenditures for the three months ended March 31, 2013, as compared to the three months ended March 31, 2012. Cash used for oil and natural gas properties capital expenditures for the three months ended March 31, 2012 was primarily attributable to our operated drilling and completion activities in the Eagle Ford shale play in South Texas.

Effective May 8, 2013, we increased our capital expenditure budget for 2013 from $310.0 million to $325.0 million, as we anticipate the acquisition of additional leasehold interests throughout 2013, particularly in Southeast New Mexico and West Texas. We also plan to maintain leasing efforts in the Eagle Ford play and the Haynesville play as opportunities arise. Expenditures for the acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipate investing $325.0 million in capital for acquisition, exploration and development activities in 2013 as follows:

	Amount (in millions)
Exploration, development drilling and completion costs	$ 260.0
Pipeline and infrastructure expenditures	25.0
Leasehold acquisition and 2-D and 3-D seismic data	40.0
Total	$ 325.0

At March 31, 2013, we had incurred approximately $68.6 million or about 21% of our 2013 capital expenditure budget of $325.0 million. During the first three months of 2013, our drilling and completion costs for new wells have been less than we budgeted, although our costs for production facilities and other infrastructure have exceeded our initial estimates. Overall, at March 31, 2013, we are executing our 2013 capital expenditure program largely as planned and remain within our capital expenditure budget for 2013. While we have budgeted $325.0 million for 2013, 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 2013.

For further information regarding our anticipated capital expenditure budget in 2013, see "Business – General" in the Annual Report. Our 2013 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 $55.0 million for the three months ended March 31, 2013, as compared to net cash provided by financing activities of $39.7 million for the three months ended March 31, 2012. The net cash provided by financing activities for the three months ended March 31, 2013 was attributable to borrowings under our Credit Agreement. The net cash provided by financing activities for the three months ended March 31, 2012 was principally due to the total proceeds from our initial public offering of $146.5 million and incremental borrowings of $25.0 million, 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 three months ended March 31, 2012.

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, 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.

	Three Months Ended March 31,	
(In thousands)	2013	2012
Unaudited Adjusted EBITDA Reconciliation to Net Income (Loss):		
Net (loss) income	$(15,505)	$ 3,801
Interest expense	1,271	308
Total income tax provision	46	3,064
Depletion, depreciation and amortization	28,232	11,205
Accretion of asset retirement obligations	81	53
Full-cost ceiling impairment	21,230	-
Unrealized loss on derivatives	4,825	3,270
Stock-based compensation expense	492	(363)
Adjusted EBITDA	$ 40,672	$21,338

	Three Months Ended March 31,	
(In thousands)	2013	2012
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:		
Net cash provided by operating activities	$ 32,229	$ 5,110
Net change in operating assets and liabilities	7,126	15,920
Interest expense	1,271	308
Current income tax provision	46	-
Adjusted EBITDA	$ 40,672	$21,338

Our Adjusted EBITDA increased by approximately $19.3 million to approximately $40.7 million, or an increase of approximately 91% for the three months ended March 31, 2013, as compared to the three months ended March 31, 2012. 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 three months ended March 31, 2013, as compared to the three months ended March 31, 2012.

Credit Agreement

On September 28, 2012, we entered into our third amended and restated senior secured revolving Credit Agreement, which matures in December 2016. Among other things, this amendment increased the maximum facility amount from $400.0 million to $500.0 million, increased the borrowing base from $125.0 million to $200.0 million and named RBC as administrative agent. In addition, the amendment provided for a conforming borrowing base of $165.0 million. The borrowing base will automatically be reduced to the conforming borrowing base on the earlier of (i) December 31, 2013 or (ii) the closing of a secondary public offering of equity interests that results in net cash proceeds to us in an amount greater than or equal to $25.0 million. MRC Energy Company is the borrower under the 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, the parent corporation. Various commodity hedging agreements with certain of the lenders under the Credit Agreement (or affiliates thereof) are also secured by the collateral of and guaranteed by the eligible subsidiaries of MRC Energy Company.

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 our proved oil and natural gas reserves at December 31 and June 30 of each year, respectively.

Both we and the lenders may request an unscheduled redetermination of the borrowing base once each between scheduled redetermination dates. During the fourth quarter of 2012, the Company requested one such redetermination, and on December 20, 2012, the borrowing base was increased from $200.0 million to $215.0 million as a result of the lenders' review of the Company's proved oil and natural gas reserves at September 30, 2012. In connection with this borrowing base redetermination, the conforming borrowing base was increased to $180.0 million at December 20, 2012.

During the first quarter of 2013, our lenders completed their review of our proved oil and natural gas reserves at December 31, 2012, and as a result, on March 11, 2013, the borrowing base was increased to $255.0 million and the conforming borrowing base was increased to $220.0 million. The March 11, 2013 redetermination constituted the regularly scheduled May 1 redetermination. In late April 2013, we requested an unscheduled borrowing base redetermination and anticipate that the borrowing base will be increased during the second quarter of 2013. 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 is determined based on market conditions at the time of the borrowing base increase. If, upon a redetermination or the automatic reduction of the borrowing base to the conforming borrowing base, 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.

Between January 1, 2013 and March 31, 2013, we borrowed $55.0 million under the Credit Agreement to finance a portion of our working capital requirements and capital expenditures. At March 31, 2013, we had $205.0 million in borrowings outstanding under the Credit Agreement and approximately $1.3 million in outstanding letters of credit issued pursuant to the Credit Agreement. At March 31, 2013, our outstanding borrowings bore interest at an effective interest rate of approximately 3.6% per annum. We expect to access future borrowings under our Credit Agreement to fund a portion of our 2013 capital expenditure requirements in excess of amounts available from our operating cash flows. 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, and particularly our proved developed oil and natural gas reserves, primarily attributable to our ongoing drilling operations in the Eagle Ford shale. From March 31, 2013 through May 9, 2013, we borrowed an additional $25.0 million under the Credit Agreement to finance a portion of our working capital requirements and the acquisition of additional leasehold interests in Southeast New Mexico. At May 9, 2013, we had $230.0 million in borrowings outstanding under the Credit Agreement and approximately $1.3 million in outstanding letters of credit issued pursuant to the Credit Agreement.

If we borrow funds as a base rate loan, such borrowings will bear interest at a rate equal to the higher of (i) the prime rate for such day or (ii) the Federal Funds Effective Rate on such day, plus 0.50% or (iii) the daily adjusting LIBOR rate plus 1.0% plus, in each case, an amount from 0.75% to 2.25% 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 LIBOR rate by (B) a percentage equal to 100% minus the maximum rate during such interest calculation period at which RBC 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 1.75% to 3.25% of such outstanding loan depending on the level of borrowings under the Credit Agreement. The interest period for Eurodollar borrowings may be one, two, three or six months as designated by us. A commitment fee of 0.375% to 0.50%, depending on the unused availability under the Credit Agreement, is also paid quarterly in arrears. We include this commitment fee, any amortization of deferred financing costs (including origination, borrowing base increase and amendment fees) and annual agency fees as interest expense and 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 consolidated total current liabilities, of 1.0 or greater measured at the end of each fiscal quarter beginning March 31, 2014 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 amounts 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 March 31, 2013, we believe that we were in compliance with the terms of our Credit Agreement.

Off-Balance Sheet Arrangements

At March 31, 2013, we did not have any off-balance sheet arrangements.

Obligations and Commitments

We had the following material contractual obligations and commitments at March 31, 2013:

	Payments Due by Period				
(In thousands)	**Total**	**Less Than 1 Year**	**1 -3 Years**	**3 -5 Years**	**More Than 5 Years**
Contractual Obligations:					
Revolving credit borrowings and term loan, including letters of credit[(1)]	$206,345	$ 1,345	$ -	$205,000	$ -
Office lease	7,348	680	1,492	1,564	3,612
Non-operated drilling commitments[(2)]	4,296	4,296	-	-	-
Drilling rig contracts[(3)]	4,606	4,606	-	-	-
Asset retirement obligations	6,506	760	412	529	4,805
Gas processing agreement[(4)]	15,228	5,985	6,695	2,548	-
Total contractual cash obligations	$244,329	$17,672	$8,599	$209,641	$8,417

(1) At March 31, 2013, we had $205.0 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 March 31, 2013, we had outstanding commitments to participate in the drilling and completion of various non-operated wells in the Haynesville and Eagle Ford shales. Our working interests in these wells are typically small, and most of these wells were in progress at March 31, 2013. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of approximately $4.3 million at March 31, 2013, which we expect to incur within the next few months.

(3) At March 31, 2013, we were party to two drilling rig contracts to explore and develop our acreage in the Eagle Ford shale in South Texas. During the first quarter of 2013, we extended one of our drilling rig contracts for an additional six months. Drilling operations under this contract began in April 2013. The second contract is for a nine-month term and drilling operations under this contract began in December 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 $4.6 million at March 31, 2013. In April 2013, one of these rigs was moved to Southeast New Mexico to begin testing our leasehold position in the Delaware Basin.

(4) Effective September 1, 2012, we entered into a firm five-year natural gas processing and transportation agreement for a significant portion of our operated natural gas production in South Texas. The undiscounted minimum commitments under this agreement total approximately $15.2 million at March 31, 2013.

General Outlook and Trends

For the three months ended March 31, 2013, oil prices ranged from a high of approximately $97.94 per Bbl in late January to a low of approximately $90.12 per Bbl in early March, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. We realized an average oil price of $105.72 per Bbl ($105.20 per Bbl including realized losses from oil derivatives) for our oil production for the three months ended March 31, 2013, as compared to $107.57 per Bbl for the three months ended March 31, 2012. At May 9, 2013, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date closed at $96.39 per Bbl as compared to $96.81 per Bbl at May 9, 2012.

We realized a weighted average oil price of $105.72 per Bbl for the three months ended March 31, 2013, which represented an uplift of $10.00 per Bbl to $12.00 per Bbl compared to NYMEX West Texas Intermediate oil prices during the first quarter of 2013. Most of our Eagle Ford oil production in South Texas is sold based on a Louisiana Light Sweet oil price index less transportation costs. During the first quarter of 2013, the differential between Louisiana Light Sweet and West Texas Intermediate oil prices was close to $20.00 per Bbl at times. Subsequent to March 31, 2013, the price differential between these two benchmark prices has begun to narrow, and as a result, we may not realize similar uplifts to West Texas Intermediate oil prices in future periods.

For the three months ended March 31, 2013, natural gas prices ranged from a low of approximately $3.11 per MMBtu in early January to a high of approximately $4.07 per MMBtu in late March, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. We realized a natural gas price of $3.41 per Mcf ($3.61 per Mcf including realized gains from natural gas derivatives) for our natural gas production for the three months ended March 31, 2013, as compared to $2.40 per Mcf ($3.36 per Mcf including realized gains from natural gas derivatives) for the three months ended March 31, 2012. At May 9, 2013, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date closed at $3.98 per MMBtu as compared to $2.47 per MMBtu at May 9, 2012.

The prices we receive for oil, natural gas and natural gas liquids heavily influence our revenues, profitability, cash flows available for capital expenditures, access to capital and future rate of growth. Oil, natural gas and natural gas liquids 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, natural gas and natural gas liquids have been volatile and these markets will likely continue to be volatile in the future. Declines in oil, natural gas or natural gas liquids prices not only reduce our revenues, but could also reduce the amount of oil, natural gas and natural gas liquids we can produce economically. From time to time, we use derivative financial instruments to mitigate our exposure to commodity price risk associated with oil, natural gas and natural gas liquids prices. Even so, decisions as to whether and what volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil, natural gas and natural gas liquids prices, and we may not always employ the optimal hedging strategy. Should oil, natural gas or natural gas liquids 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 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 anticipate similar rapid initial production declines in wells we complete in the Wolfcamp and Bone Spring plays as well. 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, natural gas and natural gas liquids 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, cash flows and availability under our Credit Agreement.

We must focus our efforts on increasing oil and natural 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, 2012 as set forth in the Annual Report.

Commodity price exposure. We are exposed to market risk as the prices of oil, natural gas and natural gas liquids 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 anticipated future production.

We use costless (or zero-cost) collars and/or swap contracts to manage risks related to changes in oil, natural gas and natural gas liquids prices. Costless collars provide 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, these arrangements are initially "costless" to us. In the case of a costless collar, the put option and the call option have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over a specified time, providing downside price protection.

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. At March 31, 2013, Comerica Bank, RBC and The Bank of Nova Scotia (or affiliates thereof) were the counterparties for all of our derivative instruments. We have evaluated the credit standing of the counterparties in determining the fair value of our derivative financial instruments.

We have entered into various costless collar contracts to mitigate our exposure to fluctuations in oil prices, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss 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 one or more of these collars, we receive from our 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 one or more of these collars, we pay to our 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 swap contracts to mitigate our exposure to fluctuations in oil prices, each with an established fixed price. For each calculation period, the specified price for determining the realized gain or loss pursuant to any of these transactions is the arithmetic average of the settlement prices for 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 fixed price established by one or more of these swaps, we receive from our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract oil volume. When the settlement price is above the fixed price established by one or more of these swaps, we pay to our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract oil volume.

We have entered into various costless collar transactions for natural gas, 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 one or more of these collars, we receive from our 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 one or more of these collars, we pay to our counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract natural gas volume.

We have entered into various swap contracts to mitigate our exposure to fluctuations in natural gas liquids ("NGL") prices, each with an established fixed price. For each calculation period, the settlement price for determining the realized gain or loss to us pursuant to any of these transactions is the arithmetic average of any current month for delivery on the nearby month futures contracts of the underlying commodity as stated on the "Mont Belvieu Spot Gas Liquids Prices: NON-TET prop" on the pricing date. When the settlement price is below the fixed price established by one or more of these swaps, we receive from our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract NGL volume. When the settlement price is above the fixed price established by one or more of these swaps, we pay to our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract NGL volume.

At March 31, 2013, we had various costless collar contracts open and in place to mitigate our 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 2013, 2014 and 2015.

At March 31, 2013, we had various swap contracts open and in place to mitigate our exposure to oil and NGL price volatility, each with a specific term (calculation period), notional quantity (volume hedged) and fixed price. Each contract is set to expire at varying times during 2013 and 2014.

The following is a summary of the Company's open costless collar contracts for oil and natural gas and open swap contracts for oil and natural gas liquids at March 31, 2013.

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil	04/01/2013 - 12/31/2013	20,000	85.00	102.25	$ (140)
Oil	04/01/2013 - 12/31/2013	20,000	90.00	115.00	292
Oil	04/01/2013 - 12/31/2013	20,000	85.00	110.40	96
Oil	04/01/2013 - 12/31/2013	20,000	85.00	108.80	71
Oil	04/01/2013 - 06/30/2014	8,000	90.00	114.00	324
Oil	04/01/2013 - 06/30/2014	12,000	90.00	115.50	502
Oil	07/01/2013 - 12/31/2013	20,000	90.00	102.80	49
Oil	01/01/2014 - 12/31/2014	15,000	85.00	97.50	(122)
Oil	01/01/2014 - 12/31/2014	30,000	85.00	98.00	(179)
Oil	01/01/2014 - 12/31/2014	15,000	87.00	97.00	(41)
Oil	01/01/2014 - 12/31/2014	20,000	90.00	97.00	209
Oil	01/01/2014 - 12/31/2014	15,000	90.00	97.90	238
Oil	01/01/2014 - 12/31/2014	15,000	90.00	98.00	235
Total open oil costless collar contracts					1,534

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas	04/01/2013 - 07/31/2013	150,000	4.50	5.75	297
Natural Gas	04/01/2013 - 12/31/2013	100,000	3.00	3.83	(359)
Natural Gas	04/01/2013 - 12/31/2013	100,000	3.00	4.95	(46)
Natural Gas	04/01/2013 - 12/31/2013	100,000	3.00	4.96	(45)
Natural Gas	04/01/2013 - 12/31/2013	100,000	3.25	4.41	(114)
Natural Gas	04/01/2013 - 12/31/2013	100,000	3.25	4.44	(107)
Natural Gas	04/01/2013 - 12/31/2013	100,000	3.50	4.37	(100)
Natural Gas	07/01/2013 - 12/31/2013	150,000	3.00	4.24	(238)
Natural Gas	08/01/2013 - 12/31/2013	80,000	3.75	4.57	(15)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.00	5.15	(153)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.21	(89)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.22	(88)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.37	(68)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.42	(60)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.50	4.90	(94)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.75	4.77	(48)
Natural Gas	01/01/2015 - 12/31/2015	200,000	3.75	5.04	(51)
Total open natural gas costless collar contracts					(1,378)

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Fixed Price ($/Bbl)	Fair Value of Liability (thousands)
Oil	04/01/2013 - 12/31/2013	10,000	90.20	(591)
Oil	04/01/2013 - 12/31/2013	10,000	90.65	(551)
Total open oil swap contracts				(1,142)

Commodity	Calculation Period	Notional Quantity (Gal/month)	Fixed Price ($/Gal)	Fair Value of Asset (Liability) (thousands)
Purity Ethane	04/01/2013 - 12/31/2013	110,000	0.335	29
Purity Ethane	04/01/2013 - 12/31/2013	110,000	0.355	49
Propane	04/01/2013 - 12/31/2013	53,000	0.953	(5)
Propane	04/01/2013 - 12/31/2013	106,000	0.960	(5)
Propane	04/01/2013 - 12/31/2013	53,000	1.001	17
Propane	01/01/2014 - 12/31/2014	116,000	0.950	(4)
Normal Butane	04/01/2013 - 12/31/2013	14,700	1.455	2
Normal Butane	04/01/2013 - 12/31/2013	14,700	1.560	16
Normal Butane	04/01/2013 - 12/31/2013	21,000	1.575	26
Normal Butane	04/01/2013 - 12/31/2013	117,000	1.575	146
Normal Butane	01/01/2014 - 12/31/2014	17,500	1.540	25
Normal Butane	01/01/2014 - 12/31/2014	45,500	1.550	70
Isobutane	04/01/2013 - 12/31/2013	7,000	1.515	1
Isobutane	04/01/2013 - 12/31/2013	7,000	1.625	8
Isobutane	04/01/2013 - 12/31/2013	43,500	1.675	71
Isobutane	04/01/2013 - 12/31/2013	23,000	1.675	35
Isobutane	01/01/2014 - 12/31/2014	22,000	1.640	35
Isobutane	01/01/2014 - 12/31/2014	37,000	1.640	62
Natural Gasoline	04/01/2013 - 12/31/2013	12,000	2.025	(6)
Natural Gasoline	04/01/2013 - 12/31/2013	12,000	2.085	-
Natural Gasoline	04/01/2013 - 12/31/2013	12,000	2.102	2
Natural Gasoline	04/01/2013 - 12/31/2013	36,000	2.105	6
Natural Gasoline	04/01/2013 - 12/31/2013	90,500	2.148	45
Natural Gasoline	01/01/2014 - 12/31/2014	30,000	1.970	1
Natural Gasoline	01/01/2014 - 12/31/2014	41,000	2.000	14
Total open NGL swap contracts				640
Total open derivative financial instruments				$ (346)

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)) was performed under the supervision and with the participation of the Company’s management, including its Chief Executive Officer and Chief Financial Officer. Based on that evaluation, the Company’s Chief Executive Officer and Chief Financial Officer concluded that the Company’s disclosure controls and procedures were effective as of March 31, 2013, to ensure that information required to be disclosed in the reports the Company files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to the Company’s management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Evaluation of Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of the Company’s management, including its Chief Executive Officer and Chief Financial Officer, the Company determined that, during the first quarter of 2013, there were no changes in its internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

Part II—Other Information

Item 1. Legal Proceedings

See Part 1, Item 1 – "Financial Statements," "Note 9 – 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 the Annual Report.

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

None.

Item 6. Exhibits

A list of exhibits filed herewith is contained in the Exhibit Index that immediately precedes such exhibits and is incorporated by reference herein.

Table of Contents

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: May 10, 2013	By: /s/ Joseph Wm. Foran Joseph Wm. Foran Chairman, President and Chief Executive Officer
Date: May 10, 2013	By: /s/ David E. Lancaster David E. Lancaster Executive Vice President, Chief Operating Officer and Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	Description
10.1	Second Amendment to the Matador Resources Company 2012 Long-Term Incentive Plan dated March 8, 2013 (incorporated by reference to Exhibit 10.17 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.2	Eighth Amendment to the Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated March 8, 2013 (incorporated by reference to Exhibit 10.27 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.3	First Amendment to Third Amended and Restated Credit Agreement dated as of March 11, 2013, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the year ended December 31, 2012).
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 March 31, 2013, 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 - Unaudited (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.

Exhibit 23.1

NSAI 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 March 31, 2013, and the inclusion of our corresponding audit letter, dated April 26, 2013, in the Quarterly Report on Form 10-Q of Matador Resources Company for the fiscal quarter ended March 31, 2013, 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 April 26, 2013, in Matador Resources Company's Form S-8 (333-180641) and in Matador Resources Company's Form S-3 (333-187808).

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

Dallas, Texas
May 10, 2013

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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) 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. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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.

May 10, 2013

/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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) 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. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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.

May 10, 2013

/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 March 31, 2013 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.

Dated: May 10, 2013

/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 March 31, 2013 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.

Dated: May 10, 2013

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

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

April 26, 2013

Mr. Indranil (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 March 31, 2013, 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 March 31, 2013, for the audited properties:

	Net Reserves		Future Net Revenue (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	5,368	51,486	471,080	318,361
Proved Developed Non-Producing	6	692	1,022	617
Proved Undeveloped	5,338	25,306	252,936	119,098
Total Proved	10,712	77,484	725,038	438,075

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 March 31, 2013, 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 April 2012 through March 2013. For oil volumes, the average West Texas Intermediate posted price of $89.17 per barrel is adjusted by lease for quality, transportation fees, and regional price differentials. For gas volumes, the average Henry Hub spot price of $2.95 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 $99.41 per barrel of oil and $2.78 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 are limited to 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. Estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

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,
P.E. 61794
Executive Vice President

Date Signed: April 26, 2013

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