Matador Resources Co
Form 10-Q
November 08, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 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. x 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). x 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	x
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 x No

As of November 7, 2013, there were 65,633,487 shares of the registrant's common stock, par value $0.01 per share, outstanding.

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FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 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)

	September 30, 2013	December 31, 2012
ASSETS		
Current assets		
Cash	$ 6,330	$ 2,095
Certificates of deposit	40	230
Accounts receivable		
Oil and natural gas revenues	26,722	24,422
Joint interest billings	2,600	4,118
Other	1,077	974
Derivative instruments	1,037	4,378
Deferred income taxes	1,948	—
Lease and well equipment inventory	687	877
Prepaid expenses	3,250	1,103
Total current assets	43,691	38,197
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	951,736	763,527
Unproved and unevaluated	213,084	149,675
Other property and equipment	29,219	27,258
Less accumulated depletion, depreciation and amortization	(445,193)	(349,370)
Net property and equipment	748,846	591,090
Other assets		
Derivative instruments	995	771
Deferred income taxes	—	411
Other assets	2,288	1,560
Total other assets	3,283	2,742
Total assets	$ 795,820	$ 632,029
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current liabilities		
Accounts payable	$ 20,280	$ 28,120
Accrued liabilities	50,048	59,179
Royalties payable	10,352	6,541
Derivative instruments	4,178	670
Advances from joint interest owners	10	1,515
Income taxes payable	980	—
Deferred income taxes	—	411
Other current liabilities	87	56
Total current liabilities	85,935	96,492
Long-term liabilities		
Borrowings under Credit Agreement	145,000	150,000
Asset retirement obligations	6,147	5,109
Deferred income taxes	3,609	—
Other long-term liabilities	2,463	1,324

Total long-term liabilities	157,219	156,433
Commitments and contingencies (Note 10)		
Shareholders' equity		
Common stock - $0.01 par value, 80,000,000 shares authorized; 66,927,261 and 56,778,718 shares issued; and 65,625,418 and 55,577,667 shares outstanding, respectively	670	568
Additional paid-in capital	548,051	404,311
Retained earnings (deficit)	14,710	(15,010)
Treasury stock, at cost, 1,301,843 and 1,201,051 shares, respectively	(10,765)	(10,765)
Total shareholders' equity	552,666	379,104
Total liabilities and shareholders' equity	$ 795,820	$ 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Revenues				
Oil and natural gas revenues	$81,868	$38,008	$199,367	$103,250
Realized (loss) gain on derivatives	(1,165)	3,371	(519)	11,147
Unrealized loss on derivatives	(9,327)	(12,993)	(6,626)	(1,149)
Total revenues	71,376	28,386	192,222	113,248
Expenses				
Production taxes and marketing	6,559	2,822	15,107	7,605
Lease operating	8,569	6,491	29,608	17,511
Depletion, depreciation and amortization	26,127	21,680	74,593	52,799
Accretion of asset retirement obligations	86	59	248	170
Full-cost ceiling impairment	—	3,596	21,229	36,801
General and administrative	5,395	3,439	14,146	11,321
Total expenses	46,736	38,087	154,931	126,207
Operating income (loss)	24,640	(9,701)	37,291	(12,959)
Other income (expense)				
Net loss on asset sales and inventory impairment	—	—	(192)	(60)
Interest expense	(2,038)	(144)	(4,919)	(453)
Interest and other income	66	55	181	157
Total other expense	(1,972)	(89)	(4,930)	(356)
Income (loss) before income taxes	22,668	(9,790)	32,361	(13,315)
Income tax provision (benefit)				
Current	902	188	980	188
Deferred	1,661	(781)	1,661	(1,430)
Total income tax provision (benefit)	2,563	(593)	2,641	(1,242)
Net income (loss)	$20,105	$(9,197)	$29,720	$(12,073)
Earnings (loss) per common share				
Basic				
Class A	$0.35	$(0.17)	$0.53	$(0.23)
Class B	$—	$—	$—	$(0.03)
Diluted				
Class A	$0.35	$(0.17)	$0.53	$(0.23)
Class B	$—	$—	$—	$(0.03)
Weighted average common shares outstanding				
Basic				
Class A	58,016	55,271	55,766	53,379
Class B	—	—	—	140
Total	58,016	55,271	55,766	53,519
Diluted				
Class A	58,152	55,271	55,889	53,379
Class B	—	—	—	140
Total	58,152	55,271	55,889	53,519

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

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Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY - UNAUDITED
(In thousands)
For the Nine Months Ended September 30, 2013

	Common Stock		Additional	Retained	Treasury Stock		
	Shares	Amount	Paid-In Capital	(Deficit) Earnings	Shares	Amount	Total
Balance at January 1, 2013	56,779	$568	$404,311	$(15,010)	1,201	$(10,765)	$379,104
Issuance of common stock	9,778	98	148,971	—	—	—	149,069
Cost to issue equity	—	—	(7,389)	—	—	—	(7,389)
Common stock issued to Board advisors	16	—	38	—	—	—	38
Stock options expense related to equity based awards	—	—	882	—	—	—	882
Liability based stock option awards settled	—	—	114	—	—	—	114
Restricted stock issued	354	4	(4)	—	—	—	—
Restricted stock forfeited	—	—	(22)	—	101	—	(22)
Restricted stock and restricted stock units expense	—	—	1,150	—	—	—	1,150
Current period net income	—	—	—	29,720	—	—	29,720
Balance at September 30, 2013	66,927	$670	$548,051	$14,710	1,302	$(10,765)	$552,666

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

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Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS - UNAUDITED
(In thousands)

	Nine Months Ended September 30, 2013	2012
Operating activities		
Net income (loss)	$29,720	$(12,073)
Adjustments to reconcile net income (loss) to net cash provided by operating activities		
Unrealized loss on derivatives	6,626	1,149
Depletion, depreciation and amortization	74,593	52,799
Accretion of asset retirement obligations	248	170
Full-cost ceiling impairment	21,229	36,801
Stock-based compensation expense	2,763	(223)
Deferred income tax provision (benefit)	1,661	(1,430)
Net loss on asset sales and inventory impairment	192	60
Changes in operating assets and liabilities		
Accounts receivable	(886)	(8,718)
Lease and well equipment inventory	198	(285)
Prepaid expenses	(2,148)	179
Other assets	(728)	(650)
Accounts payable, accrued liabilities and other current liabilities	(10,702)	6,105
Royalties payable	3,812	4,065
Advances from joint interest owners	(1,505)	1,782
Income taxes payable	980	188
Other long-term liabilities	1,139	406
Net cash provided by operating activities	127,192	80,325
Investing activities		
Oil and natural gas properties capital expenditures	(257,216)	(212,702)
Expenditures for other property and equipment	(3,058)	(5,297)
Purchases of certificates of deposit	(61)	(416)
Maturities of certificates of deposit	251	1,485
Net cash used in investing activities	(260,084)	(216,930)
Financing activities		
Repayments of borrowings under Credit Agreement	(130,000)	(123,000)
Borrowings under Credit Agreement	125,000	116,000
Proceeds from issuance of common stock	149,069	146,510
Swing sale profit contribution	—	24
Cost to issue equity	(6,933)	(11,599)
Proceeds from stock options exercised	—	2,660
Taxes paid related to net share settlement of stock-based compensation	(9)	—
Payment of dividends - Class B	—	(96)
Net cash provided by financing activities	137,127	130,499
Increase (decrease) in cash	4,235	(6,106)
Cash at beginning of period	2,095	10,284
Cash at end of period	$6,330	$4,178

Supplemental disclosures of cash flow information (Note 11)

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

Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED

NOTE 1 - NATURE OF OPERATIONS

Matador Resources Company ("Matador" 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 an emphasis on oil and natural gas shale and other unconventional 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 the Permian Basin 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 it 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 and West Texas. 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, transports limited quantities of third-party natural gas and disposes of limited quantities of third-party salt water.

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 September 30, 2013, consolidated results of operations for the three and nine months ended September 30, 2013 and 2012, consolidated changes in shareholders' equity for the nine months ended September 30, 2013 and consolidated cash flows for the nine months ended September 30, 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 the 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

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

accruals. While the Company believes its estimates are reasonable, changes in facts and assumptions or the discovery of new information may result in revised estimates. Actual results could differ from these estimates.

Property and Equipment

The Company uses the full-cost method of accounting for its investments in oil and natural gas properties. Under this method of accounting, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing the Company’s activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects and general and administrative expenses directly related to exploration and development activities, but do not include any costs related to production, selling or general corporate administrative activities. The Company capitalized approximately $2.3 million and $1.7 million of its general and administrative costs for the nine months ended September 30, 2013 and 2012, respectively. The Company capitalized approximately $1.2 million and $1.0 million of its interest expense for the nine months ended September 30, 2013 and 2012, respectively.

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

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

The commodity prices used to estimate oil and natural gas reserves are based on unweighted, arithmetic averages of first-day-of-the-month oil and natural gas prices for the previous 12-month period. For the period from October 2012 through September 2013, these average oil and natural gas prices were $91.69 per Bbl and $3.605 per MMBtu (million British thermal units), respectively. For the period from October 2011 through September 2012, these average oil and natural gas prices were $91.48 per Bbl and $2.826 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 September 30, 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 September 30, 2013, 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 September 30, 2013. 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 for the three months ended March 31, 2013. These charges are reflected in the Company’s unaudited condensed consolidated statement of operations for the nine months ended September 30, 2013. Using the average commodity prices, as adjusted, to determine the Company’s estimated proved oil and natural gas reserves at June 30, 2012 and September 30, 2012, the Company’s net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $21.3 million and $2.3 million, respectively. The Company recorded an impairment charge of $33.2 million and $3.6 million to its net capitalized costs and a deferred income tax credit of $11.9 million and $1.3 million, related to the full-cost

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NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

ceiling limitation at June 30, 2012 and September 30, 2012, respectively. These charges are reflected in the Company's unaudited condensed consolidated statement of operations for the nine months ended September 30, 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.

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 nine months ended September 30, 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 September 30, 2013, the Company had not paid any dividends to holders of the Class A shares. Concurrent with the completion of the Company’s 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 and nine months ended September 30, 2013 and 2012 (in thousands, except per share data).

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net income (loss) - numerator				
Net income (loss)	$20,105	$(9,197)	$29,720	$(12,073)
Less dividends to Class B shareholders - distributed earnings	—	—	—	(28)
Undistributed earnings (loss)	$20,105	$(9,197)	$29,720	$(12,101)
Weighted average common shares outstanding - denominator				
Basic				
Class A	58,016	55,271	55,766	53,379
Class B	—	—	—	140
Total	58,016	55,271	55,766	53,519
Diluted				
Class A				
Weighted average common shares outstanding for basic earnings (loss) per share	58,016	55,271	55,766	53,379
Dilutive effect of options and restricted stock units	136	—	123	—
Class A weighted average common shares outstanding - diluted	58,152	55,271	55,889	53,379
Class B				
Weighted average common shares outstanding - no associated dilutive shares	—	—	—	140
Total diluted weighted average common shares outstanding	58,152	55,271	55,889	53,519

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Earnings (loss) per common share				
Basic				
Class A				
Distributed earnings	$—	$—	$—	$—
Undistributed earnings (loss)	$0.35	$(0.17)	$0.53	$(0.23)
Total	$0.35	$(0.17)	$0.53	$(0.23)
Class B				
Distributed earnings	$—	$—	$—	$0.20
Undistributed loss	$—	$—	$—	$(0.23)
Total	$—	$—	$—	$(0.03)
Diluted				
Class A				
Distributed earnings	$—	$—	$—	$—
Undistributed earnings (loss)	$0.35	$(0.17)	$0.53	$(0.23)
Total	$0.35	$(0.17)	$0.53	$(0.23)
Class B				
Distributed earnings	$—	$—	$—	$0.20

Undistributed loss	$—	$—	$—	$(0.23)
Total	$—	$—	$—	$(0.03)

A total of 1,085,152 options to purchase shares of the Company's Class A common stock and 151,051 restricted stock units were excluded from the calculations above for the three and nine months ended September 30, 2012, because their effects were anti-dilutive. Additionally, 233,349 restricted shares, which are participating securities, were excluded from the calculations above for the three and nine months ended September 30, 2012, as these security holders do not have the obligation to share in the losses of the Company.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

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 Company adopted ASU 2013-01 effective January 1, 2013, together with the adoption of ASU 2011-11. The adoption of ASUs 2013-01 and 2011-11 did not have a material effect on the Company's consolidated financial statements but did require certain additional disclosures (see Note 8).

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 Company adopted ASU 2011-11 effective January 1, 2013, together with the adoption of ASU 2013-01. The adoption of ASUs 2011-11 and 2013-01 did not have a material effect on the Company's consolidated financial statements but did require certain additional disclosures (see Note 8).

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 3 - COMMON STOCK

On September 10, 2013, the Company completed a public offering of 9,775,000 shares of its common stock, including 1,275,000 shares issued pursuant to the underwriters' exercise of their option to purchase additional shares. After deducting underwriting discounts, commissions and direct offering costs totaling approximately $7.4 million, the Company received net proceeds of approximately $141.7 million. The Company used a portion of the net proceeds to repay $130.0 million in outstanding borrowings under its Credit Agreement (see Note 5) in September 2013, which amounts may be reborrowed in accordance with the terms of that facility. The remaining $11.7 million of the offering net proceeds was used to fund working capital requirements.

NOTE 4 - ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company’s asset retirement obligations for the nine months ended September 30, 2013 (in thousands).

Beginning asset retirement obligations	$5,769
Liabilities incurred during period	417
Liabilities settled during period	(57)
Revisions in estimated cash flows	533
Accretion expense	248
Ending asset retirement obligations	6,910
Less: current asset retirement obligations[1]	(763)
Long-term asset retirement obligations	$6,147

(1) Included in accrued liabilities in the Company’s unaudited condensed consolidated balance sheet at September 30, 2013.

NOTE 5 - 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. 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 first quarter of 2013, the lenders completed their review of the Company’s proved oil and natural gas reserves at December 31, 2012, and on March 11, 2013, the borrowing base was increased from $215.0 million to $255.0 million. In connection with this borrowing base redetermination, 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 March 11, 2013 redetermination constituted the regularly scheduled May 1 redetermination. In late April 2013, the Company requested an unscheduled redetermination of the borrowing base, and on June 4, 2013, the borrowing base was increased from $255.0 million to

$280.0 million.

On August 7, 2013, the borrowing base under the Credit Agreement was increased to $350.0 million and the conforming borrowing base was increased to $275.0 million. At that time, the Company amended the Credit Agreement to provide that the borrowing base will automatically be reduced to the conforming borrowing base at the earlier of (i) June 30, 2014 or (ii) concurrent with the issuance by the Company of senior unsecured notes in an amount greater than or equal to $10.0 million.

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NOTE 5 - REVOLVING CREDIT AGREEMENT - Continued

This August redetermination constituted the regularly scheduled November 1 redetermination. The Company may request one additional unscheduled redetermination of its borrowing base prior to the next scheduled 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.

In connection with the March, June and August 2013 borrowing base redeterminations, the Company incurred $1.1 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 $2.3 million at September 30, 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. On September 12, 2013, using a portion of the net proceeds from its public equity offering, the Company repaid $130.0 million of its outstanding borrowings under the Credit Agreement. At September 30, 2013, the Company had $145.0 million in borrowings outstanding under the Credit Agreement and approximately $0.3 million in outstanding letters of credit issued pursuant to the Credit Agreement. At September 30, 2013, the outstanding borrowings bore interest at an effective interest rate of approximately 4.0% per annum. Subsequent to September 30, 2013, the Company borrowed an additional $15.0 million to fund a portion of its working capital requirements and the acquisition of additional leasehold interests. At November 7, 2013, the Company had $160.0 million in borrowings outstanding under the Credit Agreement and approximately $0.3 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 3.00% 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 4.00% 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 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 June 30, 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 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.

NOTE 5 - 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; and
- a change of control, as defined in the Credit Agreement.

At September 30, 2013, the Company believes that it was in compliance with the terms of its Credit Agreement.

NOTE 6 - INCOME TAXES

The Company had an effective tax rate of 11.3% and 8.2% for the three and nine months ended September 30, 2013, respectively. Total income tax expense for the three and nine months ended September 30, 2013 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily to the reversal of a valuation allowance of approximately $6.7 million on the Company's federal deferred tax assets at September 30, 2013, as the Company's federal deferred tax liabilities exceeded its federal deferred tax assets at September 30, 2013, and the impact of permanent differences between book and taxable income. The Company had a net loss for the three and nine months ended September 30, 2012.

NOTE 7 - 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 or 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 8 - DERIVATIVE FINANCIAL INSTRUMENTS

From time to time, the Company uses derivative financial instruments to mitigate its exposure to commodity price risk associated with oil, 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 the Company's commodity derivatives at September 30, 2013. The Company has considered the credit standings of the counterparties in determining the fair value of its derivative financial instruments.

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.

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

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, except for purity ethane, as stated on the "Mont Belvieu Spot Gas Liquids Prices: NON-TET prop" on the pricing date. The settlement price for purity ethane is the arithmetic average of any current month for delivery on the nearby month futures contracts as stated on the "Mont Belvieu Spot Gas Liquids Prices" 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 September 30, 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 September 30, 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 8 - 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 September 30, 2013.

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil	10/01/2013 - 12/31/2013	20,000	85.00	102.25	$(131)
Oil	10/01/2013 - 12/31/2013	20,000	85.00	108.80	(22)
Oil	10/01/2013 - 12/31/2013	20,000	85.00	110.40	(13)
Oil	10/01/2013 - 12/31/2013	20,000	90.00	102.80	(105)
Oil	10/01/2013 - 12/31/2013	20,000	90.00	115.00	13
Oil	10/01/2013 - 06/30/2014	8,000	90.00	114.00	101
Oil	10/01/2013 - 06/30/2014	12,000	90.00	115.50	163
Oil	10/01/2013 - 12/31/2014	12,200	85.00	100.40	(249)
Oil	01/01/2014 - 12/31/2014	15,000	85.00	97.50	(399)
Oil	01/01/2014 - 12/31/2014	30,000	85.00	98.00	(767)
Oil	01/01/2014 - 12/31/2014	12,000	85.00	100.00	(154)
Oil	01/01/2014 - 12/31/2014	15,000	87.00	97.00	(357)
Oil	01/01/2014 - 12/31/2014	20,000	88.00	95.60	(593)
Oil	01/01/2014 - 12/31/2014	20,000	90.00	97.00	(294)
Oil	01/01/2014 - 12/31/2014	12,000	90.00	97.90	(97)
Oil	01/01/2014 - 12/31/2014	15,000	90.00	97.90	(124)
Oil	01/01/2014 - 12/31/2014	15,000	90.00	98.00	(135)
Oil	01/01/2014 - 12/31/2014	15,000	90.00	101.15	133
Total open oil costless collar contracts					(3,030)

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas	10/01/2013 - 12/31/2013	100,000	3.00	3.83	(16)
Natural Gas	10/01/2013 - 12/31/2013	100,000	3.00	4.95	1
Natural Gas	10/01/2013 - 12/31/2013	100,000	3.00	4.96	1
Natural Gas	10/01/2013 - 12/31/2013	150,000	3.00	4.24	(5)
Natural Gas	10/01/2013 - 12/31/2013	100,000	3.25	4.41	3
Natural Gas	10/01/2013 - 12/31/2013	100,000	3.25	4.44	3
Natural Gas	10/01/2013 - 12/31/2013	100,000	3.50	4.37	15
Natural Gas	10/01/2013 - 12/31/2013	80,000	3.75	4.57	54
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.00	5.15	(2)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.21	59
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.22	60
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.37	76
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.42	79
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.50	4.90	118
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.75	4.77	227

Natural Gas	01/01/2015 - 12/31/2015	200,000	3.75	5.04	331
Total open natural gas costless collar contracts					1,004

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NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Fixed Price ($/Bbl)	Fair Value of Liability (thousands)
Oil	10/01/2013 - 12/31/2013	10,000	90.20	(341)
Oil	10/01/2013 - 12/31/2013	10,000	90.65	(327)
Total open oil swap contracts				(668)

Commodity	Calculation Period	Notional Quantity (Gal/month)	Fixed Price ($/Gal)	Fair Value of Asset (Liability) (thousands)
Purity Ethane	10/01/2013 - 12/31/2013	110,000	0.335	28
Purity Ethane	10/01/2013 - 12/31/2013	110,000	0.355	35
Propane	10/01/2013 - 12/31/2013	53,000	0.953	(20)
Propane	10/01/2013 - 12/31/2013	106,000	0.960	(37)
Propane	10/01/2013 - 12/31/2013	53,000	1.001	(12)
Propane	10/01/2013 - 12/31/2013	150,000	1.103	16
Propane	01/01/2014 - 12/31/2014	116,000	0.950	(87)
Propane	01/01/2014 - 12/31/2014	116,000	1.003	8
Propane	01/01/2014 - 12/31/2014	60,000	1.015	13
Normal Butane	10/01/2013 - 12/31/2013	14,700	1.455	3
Normal Butane	10/01/2013 - 12/31/2013	14,700	1.560	8
Normal Butane	10/01/2013 - 12/31/2013	21,000	1.575	12
Normal Butane	10/01/2013 - 12/31/2013	117,000	1.575	63
Normal Butane	01/01/2014 - 12/31/2014	17,500	1.540	57
Normal Butane	01/01/2014 - 12/31/2014	45,500	1.550	143
Isobutane	10/01/2013 - 12/31/2013	7,000	1.515	2
Isobutane	10/01/2013 - 12/31/2013	7,000	1.625	4
Isobutane	10/01/2013 - 12/31/2013	43,500	1.675	34
Isobutane	10/01/2013 - 12/31/2013	23,000	1.675	18
Isobutane	01/01/2014 - 12/31/2014	22,000	1.640	87
Isobutane	01/01/2014 - 12/31/2014	37,000	1.640	156
Natural Gasoline	10/01/2013 - 12/31/2013	12,000	2.025	(3)
Natural Gasoline	10/01/2013 - 12/31/2013	12,000	2.085	—
Natural Gasoline	10/01/2013 - 12/31/2013	12,000	2.102	—
Natural Gasoline	10/01/2013 - 12/31/2013	36,000	2.105	1
Natural Gasoline	10/01/2013 - 12/31/2013	90,500	2.148	20
Natural Gasoline	01/01/2014 - 12/31/2014	30,000	1.970	(7)
Natural Gasoline	01/01/2014 - 12/31/2014	41,000	2.000	6
Total open NGL swap contracts				548
Total open derivative financial instruments				$(2,146)

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 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.

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NOTE 8 - 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, the amounts subject to master netting across different commodity types that were presented on a gross basis and the location of these balances in its unaudited condensed consolidated balance sheet as of September 30, 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	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current assets	$2,104	$(2,104)	$—	$—
Other assets	1,034	(909)	125	—
Counterparty B				
Current assets	1,741	(1,289)	452	138
Other assets	1,553	(1,039)	514	—
Counterparty C				
Current assets	2,874	(2,289)	585	301
Other assets	1,478	(1,122)	356	—
Total	$10,784	$(8,752)	$2,032	$439

The following table presents the gross liability 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, the amounts subject to master netting across different commodity types that were presented on a gross basis and the location of these balances in its unaudited condensed consolidated balance sheet as of September 30, 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	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current liabilities	$3,329	$(2,104)	$1,225	$—
Long-term liabilities	909	(909)	—	—
Counterparty B				
Current liabilities	2,749	(1,289)	1,460	138
Long-term liabilities	1,039	(1,039)	—	—
Counterparty C				
Current liabilities	3,782	(2,289)	1,493	301
Long-term liabilities	1,122	(1,122)	—	—
Total	$12,930	$(8,752)	$4,178	$439

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NOTE 8 - 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, the amounts subject to master netting across different commodity types that were presented on a gross 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 consolidated balance sheet	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current assets	$6,445	$(2,373)	$4,072	$—
Other assets	1,096	(370)	726	—
Counterparty B				
Current assets	530	(224)	306	82
Other assets	384	(339)	45	—
Total	$8,455	$(3,306)	$5,149	$82

The following table presents the gross liability 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, the amounts subject to master netting across different commodity types that were presented on a gross 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	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current liabilities	$2,373	$(2,373)	$—	$—
Long-term liabilities	370	(370)	—	—
Counterparty B				
Current liabilities	894	(224)	670	82
Long-term liabilities	339	(339)	—	—
Total	$3,976	$(3,306)	$670	$82

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The following table summarizes the location and aggregate fair value of all derivative financial instruments recorded in the consolidated statements of operations for the periods presented (in thousands).

		Three Months Ended September 30,		Nine Months Ended September 30,	
Type of Instrument	Location in Condensed Consolidated Statement of Operations	2013	2012	2013	2012
Derivative Instrument					
Oil	Revenues: Realized (loss) gain on derivatives	$(1,519)	$374	$(1,984)	$1,093
Natural Gas	Revenues: Realized gain on derivatives	161	2,996	790	10,053
NGL's	Revenues: Realized gain on derivatives	193	1	675	1
Realized (loss) gain on derivatives		(1,165)	3,371	(519)	11,147
Oil	Revenues: Unrealized loss on derivatives	(8,132)	(9,053)	(6,818)	(7,364)
Natural Gas	Revenues: Unrealized gain (loss) on derivatives	57	(3,985)	(132)	6,170
NGL's	Revenues: Unrealized (loss) gain on derivatives	(1,252)	45	324	45
Unrealized loss on derivatives		(9,327)	(12,993)	(6,626)	(1,149)
Total		$(10,492)	$(9,622)	$(7,145)	$9,998

NOTE 9 - FAIR VALUE MEASUREMENTS

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

Level 1	Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Active markets are considered to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
Level 2	Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that are valued using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.
Level 3	Unobservable inputs that are not corroborated by market data. This category is comprised of financial and non-financial assets and liabilities whose fair value is estimated based on internally developed models or methodologies using significant inputs that are generally less readily observable from objective sources.

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

At September 30, 2013 and December 31, 2012, the carrying values reported on the unaudited condensed consolidated balance sheets for accounts receivable, prepaid expenses, accounts payable, accrued liabilities, royalties payable, advances from joint interest owners, income taxes payable and other current liabilities approximate their fair values due to their short-term maturities and are classified at Level 1.

At September 30, 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.

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NOTE 9 - FAIR VALUE MEASUREMENTS - Continued

The following tables summarize the valuation of the Company’s financial assets and liabilities that were accounted for at fair value on a recurring basis in accordance with the classifications provided above as of September 30, 2013 and December 31, 2012 (in thousands).

	Fair Value Measurements at September 30, 2013 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Certificates of deposit	$—	$40	$—	$40
Oil, natural gas and NGL derivatives	—	2,032	—	2,032
Oil, natural gas and NGL derivatives	—	(4,178)	—	(4,178)
Total	$—	$(2,106)	$—	$(2,106)

	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 8. 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.

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 September 30, 2013 and December 31, 2012 (in thousands).

	Fair Value Measurements at September 30, 2013 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$—	$—	$(951)	$(951)
Total	$—	$—	$(951)	$(951)

	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 and revisions of estimated cash flows of approximately $1.0 million for the nine months ended September 30, 2013 and $1.2 million for the year ended December 31, 2012.

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NOTE 9 - FAIR VALUE MEASUREMENTS - Continued

For purposes of fair value measurement, the Company determined that lease and well equipment inventory should be classified at Level 3 when adjusted for impairment. No impairment to any equipment was recorded during the three months ended September 30, 2013. 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. 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.

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 10 - COMMITMENTS AND CONTINGENCIES

Office Lease

The Company's corporate headquarters are located at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas. In April 2013, the Company entered into the fifth amendment to its office lease agreement. This amendment increased the square footage of its corporate headquarters to 40,071 square feet effective July 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 $12.2 million at September 30, 2013. The Company paid approximately $2.0 million and $3.8 million in processing and transportation fees under this agreement during the three and nine months ended September 30, 2013.

Other Commitments

From time to time, the Company enters into contracts with third parties for drilling rigs. These contracts establish daily rates for the drilling rigs and the term of the Company's commitment for the drilling services to be provided, which are typically for one year or less. Should the Company elect to terminate a contract and if the drilling contractor were unable to secure work for the contracted drilling rigs or if the drilling contractor were unable to secure work for the contracted drilling 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 its drilling rig contracts were approximately $7.7 million at September 30, 2013.

At September 30, 2013, the Company had agreed to participate in the drilling and completion of various non-operated wells. 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 $16.7 million at September 30, 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 was involved in a dispute over a mineral rights lease involving certain acreage in Louisiana. The dispute regarded an extension of the term of a lease in Caddo Parish, Louisiana (the "Lease") where the Company had drilled or participated in the drilling of both Cotton Valley and Haynesville shale wells. At issue were 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

NOTE 10 - COMMITMENTS AND CONTINGENCIES - Continued

Company settled with one lessor who owned a 1/6th undivided interest in the minerals. The Trial Court 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 Court 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 in June 2013, the Louisiana Supreme Court reversed the decision of the Court of Appeal and reinstated the Trial Court judgment in its entirety. The plaintiffs filed an application for rehearing with the Louisiana Supreme Court, which was denied on August 30, 2013.

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, had various disputes regarding certain of the Company’s Eagle Ford shale wells and properties. Among other things, issues arose with respect to the rights and obligations of the Company and Orca under various agreements between the parties, and Orca sought 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 could withhold its consent to Orca’s putative assignment of these interests. Pursuant to agreements reached between the parties in May and June 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, the Company agreed to bear 100% of the costs to drill, complete and equip the Cowey #3H and #4H wells. Until such time as the Company has recovered 100% of the costs to drill, complete and equip the wells, all revenues generated by production from these two wells will be attributable to the Company. Following the Company’s recovery of these amounts, Orca would participate in the wells for a 25% working interest. The Company has returned $8.7 million submitted by Orca’s putative assignee. The agreements also included a mutual release of claims between the Company and Orca and provided for the dismissal of the Bexar County litigation. Orca filed a notice of non-suit on August 7, 2013.

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.

Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 11 - SUPPLEMENTAL DISCLOSURES
Accrued Liabilities
The following table summarizes the Company’s current accrued liabilities at September 30, 2013 and December 31, 2012 (in thousands).

	September 30, 2013	December 31, 2012
Accrued evaluated and unproved and unevaluated property costs	$38,879	$45,592
Accrued support equipment and facilities costs	228	1,382
Accrued cost to issue equity	456	—
Accrued stock-based compensation	—	65
Accrued lease operating expenses	5,656	5,218
Accrued interest on borrowings under Credit Agreement	117	255
Accrued asset retirement obligations	763	660
Accrued partners’ share of joint interest charges	890	3,597
Other	3,059	2,410
Total accrued liabilities	$50,048	$59,179

Supplemental Cash Flow Information
The following table provides supplemental disclosures of cash flow information for the nine months ended September 30, 2013 and 2012 (in thousands).

	Nine Months Ended September 30,	
	2013	2012
Cash paid for interest expense, net of amounts capitalized	$2,110	$442
Asset retirement obligations related to mineral properties	889	405
Asset retirement obligations related to support equipment and facilities	4	54
(Decrease) increase in liabilities for oil and natural gas properties capital expenditures	(6,288)	19,067
(Decrease) increase in liabilities for support equipment and facilities	(1,100)	482
Increase (decrease) in liabilities for accrued cost to issue equity	456	(332)
Issuance of restricted stock units for Board and advisor services	186	34
Issuance of common stock for advisor services	25	71
Stock-based compensation expense recognized as liability	715	(930)
Transfer of inventory from oil and natural gas properties	201	(91)

NOTE 12 - 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 September 30, 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.

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 13 - SUBSEQUENT EVENTS

In October and November 2013, the Company acquired approximately 9,100 gross (4,800 net) acres prospective for the Wolfcamp and Bone Spring formations in Southeast New Mexico and West Texas and approximately 900 gross (900 net) acres in the Haynesville shale play in Northwest Louisiana. The Company paid approximately $9.7 million to acquire this acreage.

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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 (the “Annual Report”) filed with the Securities and Exchange Commission ("SEC"), 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, “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;

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- 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 Quarterly 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 an emphasis on oil and natural gas shale and other unconventional 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 the Permian Basin in Southeast New Mexico and West Texas. We also operate in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. In addition, we have 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 (as defined below).

During the first quarter of 2013, we had two rigs operating full-time in South Texas and all of our operated drilling and completion activities were focused on the Eagle Ford shale. In late April 2013, we moved one of these contracted drilling rigs to Southeast New Mexico to begin a three-well exploration program testing portions of our leasehold acreage in the Permian Basin in Southeast New Mexico and West Texas, while the second rig continued to operate in the Eagle Ford shale in South

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Texas. In mid-August 2013, we added a third drilling rig to our drilling program and returned to operating two contracted drilling rigs in the Eagle Ford shale play. We expect to operate two rigs in the Eagle Ford shale for the remainder of 2013 and throughout 2014. As a result of recent acreage acquisitions in Southeast New Mexico and West Texas, the preliminary indications from our drilling program and the production results from nearby properties, we now intend to operate one contracted drilling rig in the Permian Basin for the remainder of 2013 and throughout 2014. At November 7, 2013, our two Eagle Ford rigs were operating in La Salle and Karnes Counties, Texas, respectively, and our Permian Basin rig was operating in Loving County, Texas.

As a result of adding a third drilling rig, effective September 4, 2013, we increased our 2013 capital expenditure budget from $325.0 million to $370.0 million. We anticipate the acquisition of additional leasehold interests throughout the remainder of 2013, particularly in Southeast New Mexico and West Texas, but also in the Eagle Ford shale play and the Haynesville shale play as opportunities arise. At September 30, 2013, we had incurred approximately $253.1 million, or about 68%, of our increased 2013 capital expenditure budget of $370.0 million. Overall, through September 30, 2013, we were executing our 2013 capital expenditure program largely as planned and remain within our revised capital expenditure budget for 2013. Our preliminary 2014 capital expenditure budget is estimated between $425.0 million and $450.0 million and includes approximately $400.0 million for drilling and completing oil and natural gas exploration and development wells with the remainder allocated to lease acquisitions, seismic data, pipelines and other infrastructure.

On September 10, 2013, we completed a public offering of 9,775,000 shares of our common stock, including 1,275,000 shares issued pursuant to the underwriters’ exercise of their option to purchase additional shares. After deducting underwriting discounts, commissions and direct offering costs totaling approximately $7.4 million, we received net proceeds of approximately $141.7 million. We intend to use the net proceeds from this offering primarily to fund a portion of our capital expenditures, including for the addition of the third rig to our drilling program. We also intend to use net proceeds from this offering to fund the acquisition of additional acreage in the Eagle Ford shale, the Permian Basin and the Haynesville shale and for other general working capital needs. Pending such uses, we used a portion of the net proceeds to repay $130.0 million in outstanding borrowings under our Credit Agreement in September 2013, which amounts may be reborrowed in accordance with the terms of that facility. The remaining $11.7 million of the offering net proceeds was used to fund working capital requirements.

During the first nine months of 2013, our operations were focused primarily on the exploration and development of our Eagle Ford shale properties in South Texas. During the nine months ended September 30, 2013, we completed and began producing oil and natural gas from 16 gross (16.0 net) operated and 4 gross (1.5 net) non-operated Eagle Ford shale wells. We also participated in 5 gross (0.4 net) non-operated Haynesville shale wells in Northwest Louisiana and one non-operated test of the Buda formation in South Texas (approximately 21% working interest). In late April 2013, we initiated our exploration program testing portions of our leasehold position in the Permian Basin in Southeast New Mexico and West Texas. As these are the first wells we are drilling in this area, we are collecting additional well log, core and other petrophysical data on these initial test wells. As a result, these initial wells are expected to take longer to drill and complete and will cost more than we anticipate for subsequent wells once we begin development drilling in this area. At November 7, 2013, we were continuing to evaluate potential completion intervals in our first well (Ranger 12 State #1) in a vertical wellbore and are flowing back our second well (Ranger 33 State Com #1H) after completion of the horizontal lateral in the Second Bone Spring sand in Lea County, New Mexico. At November 7, 2013, we were drilling our third exploration well on our Permian leasehold, the Dorothy White #1H well in Loving County, Texas, which is a horizontal well testing the Upper Wolfcamp. We expect to have additional results to report from these three wells later in the fourth quarter of 2013.

During the three months ended September 30, 2013 specifically, we completed and began producing oil and natural gas from 5 gross (5.0 net) operated and 2 gross (0.7 net) non-operated Eagle Ford shale wells. We completed three operated Eagle Ford wells on our Sickenius lease in Karnes County, Texas, one well on our Pena lease in northwest

La Salle County, Texas and one well on our Hennig lease in Gonzales County, Texas. The two non-operated wells were completed on our Troutt acreage in central La Salle County. The Sickenius and Pena wells began producing in early to mid-July, and the Hennig and Troutt wells began producing in early to mid-September. Given the location of the particular wells that were drilled during the third quarter, we had almost all of our Eagle Ford wells on production during the third quarter of 2013, in contrast to the second quarter when an average of 10% to 12% of our Eagle Ford production was shut-in. We plan to continue our practice of shutting in producing wells while completing and conducting fracturing operations on new wells in the Eagle Ford, and we anticipate that up to 20% of our production will be shut-in at various times during the fourth quarter of 2013.

Our average daily oil equivalent production for the three months ended September 30, 2013 was 13,482 BOE per day, including 6,703 Bbl of oil per day and 40.7 MMcf of natural gas per day, an increase of 53%, as compared to 8,838 BOE per day, including 3,291 Bbl of oil per day and 33.3 MMcf of natural gas per day, for the three months ended September 30, 2012. Our average daily oil equivalent production of 13,482 BOE per day increased 27% sequentially from an average daily oil

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equivalent production of 10,582 BOE per day, including 4,916 Bbl of oil per day and 34.0 MMcf of natural gas per day, during the second quarter of 2013. Both our oil and natural gas production increased sharply in the third quarter. Including several new wells that we brought on production late in the second quarter and early in the third quarter of 2013 that contributed fully to third quarter 2013 production volumes, we had almost all of our Eagle Ford wells on production during the third quarter of 2013, as noted above.

Our average daily oil production of 6,703 Bbl of oil per day for the three months ended September 30, 2013 was an increase of 104% from an average daily oil production of 3,291 Bbl of oil per day for the three months ended September 30, 2012. This year-over-year increase in our average daily oil equivalent production and, in particular, our average daily oil production, is directly attributable to our ongoing drilling operations in the Eagle Ford shale. Both the average daily oil equivalent production and the average daily oil production for the third quarter of 2013 were the best quarterly figures in Matador's history. Oil production comprised 50% of our total production (using a conversion ratio of one Bbl of oil per six Mcf of natural gas) for the three months ended September 30, 2013, as compared to 37% for the three months ended September 30, 2012.

Our average daily oil equivalent production for the nine months ended September 30, 2013 was approximately 11,663 BOE per day, including 5,584 Bbl of oil per day and 36.5 MMcf of natural gas per day, an increase of 36%, as compared to 8,534 BOE per day, including 2,876 Bbl of oil per day and 33.9 MMcf of natural gas per day for the nine months ended September 30, 2012. Our average daily oil production of 5,584 Bbl of oil per day was an increase of 94%, as compared to an average daily oil production of 2,876 Bbl of oil per day during the nine months ended September 30, 2012. Oil production comprised 48% of our total production (using a conversion ratio of one Bbl of oil per six Mcf of natural gas) for the nine months ended September 30, 2013, as compared to 34% for the nine months ended September 30, 2012.

Our oil and natural gas revenues for the three and nine months ended September 30, 2013 were the highest values achieved in a three and nine month period, respectively, in Matador's history. For the three months ended September 30, 2013, our oil and natural gas revenues were $81.9 million, an increase of 115% from oil and natural gas revenues of $38.0 million for the three months ended September 30, 2012. Our oil revenues increased 114% to $64.2 million during the third quarter of 2013, as compared to $30.1 million during the third quarter of 2012. This increase reflects the year-over-year doubling of our oil production, as well as a 5% increase in the weighted average oil price we realized during the three months ended September 30, 2013, as compared to the three months ended September 30, 2012. Our natural gas revenues more than doubled to $17.6 million for the three months ended September 30, 2013, as compared to natural gas revenues of $7.9 million for the three months ended September 30, 2012. This increase reflects a year-over-year increase in natural gas production of 22%, as well as the increase in the weighted average natural gas prices we realized between these periods to $4.71 per Mcf during the third quarter of 2013, as compared to $2.59 per Mcf during the third quarter of 2012. For the nine months ended September 30, 2013, our oil and natural gas revenues were $199.4 million, an increase of 93% from oil and natural gas revenues of $103.3 million for the nine months ended September 30, 2012. For the three months ended September 30, 2013, our Adjusted EBITDA was $61.5 million, an increase of 115% from an Adjusted EBITDA of $28.6 million reported for the three months ended September 30, 2012, and an increase of 51% from an Adjusted EBITDA of $40.8 million reported for the second quarter of 2013. Our Adjusted EBITDA for the nine months ended September 30, 2013 was $142.9 million, an increase of 83% from an Adjusted EBITDA of $77.9 million reported for nine months ended September 30, 2012. 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.

We realized a weighted average oil price of $104.15 per Bbl for the three months ended September 30, 2013, as compared to $99.33 per Bbl for the three months ended September 30, 2012, $105.72 per Bbl during the first quarter of 2013 and $99.77 per Bbl during the second quarter of 2013. The weighted average oil price of $104.15 per Bbl represented an uplift of about $5 per Bbl compared to NYMEX West Texas Intermediate oil prices during the third quarter of 2013, less transportation costs, as compared to an uplift of $10 to $12 per Bbl 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 second and third quarters of 2013, the differential between Louisiana Light Sweet and West Texas Intermediate oil prices narrowed significantly as compared to the first quarter of 2013, and subsequent to September 30, 2013, the differential between these two benchmark prices has continued to decrease. As a result, we may not realize similar, or any, uplifts to West Texas Intermediate oil prices in future periods. Additionally, we expect any oil production from our properties in the Permian Basin in Southeast New Mexico and West Texas will be sold on a West Texas Intermediate oil price index.

At September 30, 2013, our estimated total proved oil and natural gas reserves were 44.2 million BOE, including 13.9 million Bbl of oil and 182.0 Bcf of natural gas (30.3 million BOE), with a PV-10 of $538.6 million and a Standardized Measure of $486.1 million. At December 31, 2012, our estimated proved oil and natural gas reserves were 23.8 million BOE, including 10.5 million Bbl of oil and 80.0 Bcf of natural gas (13.3 million BOE), and at September 30, 2012, our estimated proved oil and natural gas reserves were 20.9 million BOE, including 8.4 million Bbl of oil and 74.9 Bcf of natural gas (12.5 million BOE). Our estimated proved oil reserves of 13.9 million Bbl at September 30, 2013 increased 65%, as compared to 8.4 million Bbl at September 30, 2012 and 32%, as compared to 10.5 million Bbl at December 31, 2012. 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.

The unweighted arithmetic average of the first-day-of-the-month natural gas price for the period from October 2012 through September 2013 increased to $3.605 per MMBtu, as compared to $2.757 per MMBtu for the period from January 2012 through December 2012 and $2.826 per MMBtu for the period from October 2011 through September 2012. As a result of continued improvement in natural gas prices over the past year, we added approximately 100.0 Bcf (16.7 million BOE) of proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana to our estimated total proved reserves in the second and third quarters of 2013, which are reflected in our estimated total proved reserves at September 30, 2013. We had removed 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves from our estimated total proved reserves at June 30, 2012 because the natural gas price of $3.146 per MMBtu used to estimate natural gas reserves at June 30, 2012 had declined to a level that the natural gas volumes associated with almost all of our identified Haynesville shale well locations could no longer be classified as proved undeveloped reserves.

We have added significantly to our leasehold position in the Permian Basin in Southeast New Mexico and West Texas during 2013. Between January 1 and November 7, 2013, we acquired 49,000 gross (32,800 net) acres in this area, primarily in Lea and Eddy Counties, New Mexico. Including these acreage acquisitions, at November 7, 2013, our total acreage position in the Permian Basin in Southeast New Mexico and West Texas was approximately 64,900 gross (40,400 net) acres, a majority of which we consider to be prospective for multiple oil and liquids-rich targets, including the Wolfcamp and Bone Spring plays. As noted previously, we expect to continue adding to our leasehold position in the Permian Basin throughout the remainder of 2013. We also plan to maintain leasing efforts in the Eagle Ford shale play and the Haynesville shale play as opportunities arise.

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 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 nine months ended September 30, 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. In late April 2013, we initiated our drilling operations in Southeast New Mexico, and at November 7, 2013, we have not experienced unusual difficulties in securing the necessary drilling and completion services for our operations in this area. Industry activity in Southeast New Mexico and West Texas is increasing rapidly, however, and we may encounter such difficulties as we move forward with our exploration and development operations in this area in future periods.

We did not experience any significant pipeline interruptions in South Texas during the nine months ended September 30, 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 continue to explore and develop our leasehold position in Southeast New Mexico and West Texas.

Estimated Proved Reserves

The following table sets forth our estimated total proved oil and natural gas reserves at September 30, 2013, December 31, 2012 and September 30, 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

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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 would 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 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.

	September 30, 2013	December 31, 2012	September 30, 2012
Estimated Proved Reserves Data: (1) (2)			
Estimated proved reserves:			
Oil (MBbl)(3)	13,878	10,485	8,411
Natural Gas (Bcf)(4)	182.0	80.0	74.9
Total (MBOE)(5)	44,211	23,819	20,894
Estimated proved developed reserves:			
Oil (MBbl)(3)	6,859	4,764	3,783
Natural Gas (Bcf)(4)	56.9	54.0	53.4
Total (MBOE)(5)	16,338	13,771	12,686
Percent developed	37.0 %	57.8 %	60.7 %
Estimated proved undeveloped reserves:			
Oil (MBbl)(3)	7,019	5,721	4,628
Natural Gas (Bcf)(4)	125.1	26.0	21.5
Total (MBOE)(5)	27,873	10,048	8,208
PV-10(6) (in millions)	$538.6	$423.2	$363.6
Standardized Measure(7) (in millions)	$486.1	$394.6	$333.9

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

(2) Our estimated proved reserves, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic averages of the first-day-of-the-month prices for the period from October 2012 through September 2013 were $91.69 per Bbl for oil and $3.605 per MMBtu for natural gas, for the period from January 2012 through December 2012 were $91.21 per Bbl for oil and $2.757 per MMBtu for natural gas and for the period from October 2011 through September 2012 were $91.48 per Bbl for oil and $2.826 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) One thousand barrels of oil.

(4) 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. As a result of continued improvement in natural gas prices over the past year, we added approximately 100.0 Bcf (16.7 million BOE) of proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana to our estimated

total proved reserves in the second and third quarters of 2013, which are reflected in our estimated total proved reserves at September 30, 2013.

(5) One thousand barrels of oil equivalent, estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(6) 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 September 30, 2013, December 31, 2012 and September 30, 2012 may be reconciled to the 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 September 30, 2013, December 31, 2012 and September 30, 2012 were, in millions, $52.5, $28.6 and $29.7, respectively.

(7) 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 September 30, 2013, our estimated total proved oil and natural gas reserves were 44.2 million BOE, including 13.9 million Bbl of oil and 182.0 Bcf of natural gas (30.3 million BOE), with a PV-10 of $538.6 million and a Standardized Measure of $486.1 million. At December 31, 2012, our estimated proved oil and natural gas reserves were 23.8 million BOE, including 10.5 million Bbl of oil and 80.0 Bcf of natural gas, and at September 30, 2012, our estimated proved oil and natural gas reserves were 20.9 million BOE, including 8.4 million Bbl of oil and 74.9 Bcf of natural gas. Our proved oil reserves of 13.9 million Bbl at September 30, 2013 increased 32%, as compared to 10.5 million Bbl at December 31, 2012 and 65%, as compared to 8.4 million Bbl at September 30, 2012. During the nine months ended September 30, 2013, our proved developed reserves increased 19% from 13.8 million BOE at December 31, 2012 to 16.3 million BOE at September 30, 2013. Year-over-year, our proved developed reserves increased 29% from 12.7 million BOE at September 30, 2012. At September 30, 2013, approximately 37% of our total proved reserves were proved developed reserves, 31% of our total proved reserves were oil and 69% of our total proved reserves were natural gas.

The unweighted arithmetic average of the first-day-of-the-month natural gas price for the period from October 2012 through September 2013 increased to $3.605 per MMBtu, as compared to $2.757 per MMBtu for the period from January 2012 through December 2012 and $2.826 per MMBtu for the period from October 2011 through September 2012. As a result of continued improvement in natural gas prices over the past year, we added approximately 100.0 Bcf (16.7 million BOE) of proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana to our estimated total proved reserves in the second and third quarters of 2013, which are reflected in our estimated total proved reserves at September 30, 2013. We had removed a large portion of these proved undeveloped natural gas reserves from our estimated total proved reserves at June 30, 2012, because the unweighted arithmetic average natural gas price of $3.146 per MMBtu used to estimate natural gas reserves at June 30, 2012 had declined to a level that the natural gas volumes associated with almost all of our identified Haynesville shale well locations could no longer be classified as proved undeveloped reserves. Solely as a result of including this additional 100.0 Bcf (16.7 million BOE) of proved undeveloped natural gas reserves in our total proved reserves at June 30, 2013 and September 30, 2013, respectively, the percentage of our proved reserves that are proved developed and the percentage of our proved reserves that are oil at September 30, 2013 declined from recent periods.

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.

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.

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Results of Operations

Revenues

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)
Operating Data:				
Revenues (in thousands):[1]				
Oil	$64,226	$30,074	$157,528	$81,047
Natural gas	17,642	7,934	41,839	22,203
Total oil and natural gas revenues	81,868	38,008	199,367	103,250
Realized (loss) gain on derivatives	(1,165)	3,371	(519)	11,147
Unrealized loss on derivatives	(9,327)	(12,993)	(6,626)	(1,149)
Total revenues	$71,376	$28,386	$192,222	$113,248
Net Production Volumes:[1]				
Oil (MBbl)[2]	617	303	1,524	788
Natural gas (Bcf)	3.7	3.1	10.0	9.3
Total oil equivalent (MBOE)[3]	1,240	813	3,184	2,338
Average daily production (BOE/d)[4]	13,482	8,838	11,663	8,534
Average Sales Prices:				
Oil, with realized derivatives (per Bbl)	$101.69	$100.56	$102.24	$104.25
Oil, without realized derivatives (per Bbl)	$104.15	$99.33	$103.34	$102.86
Natural gas, with realized derivatives (per Mcf)	$4.81	$3.57	$4.35	$3.47
Natural gas, without realized derivatives (per Mcf)	$4.71	$2.59	$4.20	$2.39

(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) One thousand barrels of oil.

(3) One thousand barrels of oil equivalent, estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Barrels of oil equivalent per day, estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012

Oil and natural gas revenues. Our oil and natural gas revenues increased by approximately $43.9 million to approximately $81.9 million, or an increase of 115%, for the three months ended September 30, 2013, as compared to the three months ended September 30, 2012. This increase in oil and natural gas revenues includes an increase in our oil revenues of $34.2 million and an increase in our natural gas revenues of $9.7 million for the three months ended September 30, 2013, as compared to the comparable period in 2012. Our oil revenues increased 114% to $64.2 million for the three months ended September 30, 2013, as compared to $30.1 million for the three months ended September 30, 2012. This increase in oil revenues reflects the increase in our oil production by 104% to approximately 617 MBbl of oil in the third quarter of 2013, or about 6,703 Bbl of oil per day, as compared to approximately 303 MBbl of oil produced, or about 3,291 Bbl of oil per day, in the third 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 $104.15 per Bbl that we realized for the three months ended September 30, 2013 was comparable to, but slightly higher than, the weighted average oil price of $99.33 that we realized for the three months ended September 30, 2012. The increase in natural gas revenues resulted from a higher weighted average natural gas price of $4.71 per Mcf realized during the third quarter of 2013, as compared to a weighted average natural gas price of $2.59 per Mcf realized during the third quarter of 2012 and a 22% increase in our natural gas production to approximately 3.7 Bcf of natural gas in the third quarter of 2013, as

compared to approximately 3.1 Bcf of natural gas in the third quarter of 2012.
Realized (loss) gain on derivatives. Our realized loss on derivatives was approximately $1.2 million for the three months ended September 30, 2013, as compared to a gain of approximately $3.4 million for the three months ended September 30,

2012. For the three months ended September 30, 2013, we realized a net gain of approximately $0.1 million and $0.2 million attributable to our natural gas and natural gas liquids ("NGL") derivative contracts, respectively, and we realized a net loss of approximately $1.5 million attributable to our oil derivative contracts. For the three months ended September 30, 2012, we realized a net gain of approximately $3.0 million and $0.4 million on our natural gas and oil derivative contracts, respectively. The decreased gain realized on our open natural gas derivative contracts during the respective periods resulted from higher natural gas prices during the three months ended September 30, 2013, as compared to the three months ended September 30, 2012. We realized approximately $0.12 per MMBtu hedged on all of our open natural gas derivative contracts during the three months ended September 30, 2013, as compared to $1.30 per MMBtu hedged on all of our open natural gas derivative contracts during the three months ended September 30, 2012. Our total natural gas volumes hedged for the three months ended September 30, 2013 were 17% higher than the total natural gas volumes hedged for the same period in 2012. In addition, during the third quarter of 2013, our open natural gas costless collar contracts had average floor and ceiling prices of $3.32 per MMBtu and $4.59 per MMBtu, respectively, compared to $4.07 per MMBtu and $5.30 per MMBtu, respectively, during the third quarter of 2012. The realized loss on derivatives on our open oil derivative contracts during the three months ended September 30, 2013 resulted from oil prices that were higher than the ceiling prices of several of our open costless collar contracts and the fixed prices of our open oil swap contracts. The realized gain of approximately $0.4 million during the three months ended September 30, 2012 on our open oil costless collar contracts resulted primarily from a decline in oil prices during the month of July 2012. The realized gain on our open NGL derivatives of $0.2 million during the three months ended September 30, 2013 resulted from NGL prices that were below the fixed price for most of our open NGL swap contracts during the period. We had no material realized gain or loss on our open NGL derivative contracts during the three months ended September 30, 2012.

Unrealized loss on derivatives. Our unrealized loss on derivatives was approximately $9.3 million for the three months ended September 30, 2013, as compared to an unrealized loss of approximately $13.0 million for the three months ended September 30, 2012. During the period from June 30, 2013 to September 30, 2013, the net fair value of our open oil, natural gas and NGL derivative contracts decreased from a net asset of approximately $7.2 million to a net liability of approximately $2.1 million, resulting in an unrealized loss on derivatives of approximately $9.3 million for the three months ended September 30, 2013. The net fair value of our open derivative contracts for oil and natural gas liquids decreased at September 30, 2013 compared to June 30, 2013 due to increases in futures prices for these commodities at September 30, 2013, as compared to futures prices at June 30, 2013. The fair value of our open natural gas derivative contracts decreased at September 30, 2013, as compared to June 30, 2013, due to the expiration of a contract with a significantly higher floor price relative to the average floor price of our open natural gas derivative contracts. During the period from June 30, 2012 to September 30, 2012, the net fair value of our open oil and natural gas derivative contracts decreased from $21.1 million to $8.1 million due to increases in futures prices for the these commodities, resulting in an unrealized loss on derivatives of $13.0 million for the three months ended September 30, 2012. We had no material unrealized gain or loss on our open NGL contracts during the three months ended September 30, 2012.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

Oil and natural gas revenues. Our oil and natural gas revenues increased by approximately $96.1 million to approximately $199.4 million, or an increase of about 93% for the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012. This increase in oil and natural gas revenues includes an increase in our oil revenues of $76.5 million and an increase in our natural gas revenues of $19.6 million for the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012. Our oil revenues increased by 94% to $157.5 million for the nine months ended September 30, 2013, as compared to $81.0 million for the nine months ended September 30, 2012. This increase reflects the increase in our oil production by 93% to 1,524 MBbl of oil in the nine months ended September 30, 2013, or about 5,584 Bbl of oil per day, as compared to approximately 788 MBbl of oil produced, or about 2,876 Bbl of oil per day, in the nine months ended September 30, 2012. This increased oil production is attributable to our drilling operations in the Eagle Ford shale. The weighted average oil price of $103.34 per Bbl realized for the nine months ended September 30, 2013 was comparable to, but slightly higher than, the weighted average oil price of $102.86 per Bbl that we realized for the nine months ended

September 30, 2012. The increase in natural gas revenues resulted from a higher weighted average natural gas price of $4.20 per Mcf realized during the nine months ended September 30, 2013, as compared to a weighted average natural gas price of $2.39 per Mcf realized during the nine months ended September 30, 2012 and a 7% increase in our natural gas production to approximately 10.0 Bcf for the nine months ended September 30, 2013, as compared to 9.3 Bcf for the nine months ended September 30, 2012.

Realized (loss) gain on derivatives. We realized a loss on derivatives of approximately $0.5 million for the nine months ended September 30, 2013, as compared to a gain of approximately $11.1 million for the nine months ended September 30, 2012. For the nine months ended September 30, 2013, we realized a net gain of approximately $0.8 million and $0.7 million attributable to our natural gas and NGL derivative contracts, respectively, and we realized a net loss of approximately $2.0

million attributable to our oil derivative contracts. For the nine months ended September 30, 2012, we realized a net gain of approximately $10.0 million and $1.1 million attributable to our natural gas and oil derivative contracts, respectively. The decreased gain realized from our natural gas derivative contracts resulted from higher natural gas prices during the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012. We realized approximately $0.15 per MMBtu hedged on all of our open natural gas derivative contracts during the nine months ended September 30, 2013, as compared to $1.70 per MMBtu hedged on all of our open natural gas derivatives contracts during the nine months ended September 30, 2012. Our total natural gas volumes hedged for the nine months ended September 30, 2013 were 7% higher compared to our total natural gas volumes hedged for the nine months ended September 30, 2012. In addition, for the nine months ended September 30, 2013, our open natural gas costless collar contracts had average floor and ceiling prices of $3.40 per MMBtu and $4.73 per MMBtu, respectively, compared to $4.30 per MMBtu and $5.59 per MMBtu, respectively, for the nine months ended September 30, 2012. The net loss on derivatives realized from our open oil derivative contracts during the nine months ended September 30, 2013 resulted primarily from oil prices that were in excess of the fixed prices of our open oil swap contracts, as well as oil prices that were higher than the ceiling prices on several of our open costless collar contracts, especially during the third quarter. We had no material realized gain or loss on our open NGL contracts during the nine months ended September 30, 2012.

Unrealized loss on derivatives. Our unrealized loss on derivatives was approximately $6.6 million for the nine months ended September 30, 2013, as compared to an unrealized loss of approximately $1.1 million for the nine months ended September 30, 2012. During the period from December 31, 2012 through September 30, 2013, the net fair value of our open oil, natural gas and NGL derivative contracts decreased from a net asset of approximately $4.5 million to a net liability of approximately $2.1 million, resulting in an unrealized loss on derivatives of approximately $6.6 million for the nine months ended September 30, 2013. This loss is primarily attributable to a decrease in the net fair value of our open oil contracts for the nine months ended September 30, 2013. This decrease was due primarily to an increase in oil futures prices, which decreased the net fair value of our open oil contracts by approximately $6.8 million between December 31, 2012 and September 30, 2013. During the period from December 31, 2011 through September 30, 2012, the net fair value of our open oil, natural gas and NGL derivative contracts decreased from $9.3 million to $8.1 million, resulting in an unrealized loss on derivatives of $1.1 million for the nine months ended September 30, 2012.

Expenses

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

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(In thousands, except expenses per BOE)	Three Months Ended September 30, 2013 (Unaudited)	Three Months Ended September 30, 2012 (Unaudited)	Nine Months Ended September 30, 2013 (Unaudited)	Nine Months Ended September 30, 2012 (Unaudited)
Expenses:				
Production taxes and marketing	$6,559	$2,822	$15,107	$7,605
Lease operating	8,569	6,491	29,608	17,511
Depletion, depreciation and amortization	26,127	21,680	74,593	52,799
Accretion of asset retirement obligations	86	59	248	170
Full-cost ceiling impairment	—	3,596	21,229	36,801
General and administrative	5,395	3,439	14,146	11,321
Total expenses	46,736	38,087	154,931	126,207
Operating income (loss)	24,640	(9,701)	37,291	(12,959)
Other income (expense):				
Net loss on asset sales and inventory impairment	—	—	(192)	(60)
Interest expense	(2,038)	(144)	(4,919)	(453)
Interest and other income	66	55	181	157
Total other expense	(1,972)	(89)	(4,930)	(356)
Income (loss) before income taxes	22,668	(9,790)	32,361	(13,315)
Total income tax provision (benefit)	2,563	(593)	2,641	(1,242)
Net income (loss)	$20,105	$(9,197)	29,720	$(12,073)
Expenses per BOE:				
Production taxes and marketing	$5.29	$3.47	$4.74	$3.25
Lease operating	$6.91	$7.98	$9.30	$7.49
Depletion, depreciation and amortization	$21.06	$26.66	$23.43	$22.58
General and administrative	$4.35	$4.23	$4.44	$4.84

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012

Production taxes and marketing. Our production taxes and marketing expenses increased by approximately $3.7 million to approximately $6.6 million, or an increase of approximately 132%, for the three months ended September 30, 2013, as compared to $2.8 million for the three months ended September 30, 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 115% during the three months ended September 30, 2013, as compared to the three months ended September 30, 2012. The majority of this increase was attributable to production taxes associated with the increase in oil production and associated oil revenues during the three months ended September 30, 2013 resulting from our drilling operations in the Eagle Ford shale in South Texas. Our total production was comprised of approximately 50% oil and 50% natural gas for the three months ended September 30, 2013, as compared to approximately 37% oil and 63% natural gas during the same period in 2012. On a unit-of-production basis, our production taxes and marketing expenses increased by 52% to $5.29 per BOE for the three months ended September 30, 2013, as compared to $3.47 per BOE for the three months ended September 30, 2012. Production taxes on a unit-of-production basis on our oil and natural gas production in Texas are effectively higher than the production taxes on a unit-of-production basis on our production in Louisiana. As a result, the shift in our focus from the Haynesville shale in Northwest Louisiana and East Texas to the Eagle Ford shale in South Texas has also caused our production taxes on a unit-of-production basis to increase.

Lease operating expenses. Our lease operating expenses increased by approximately $2.1 million to approximately $8.6 million, or an increase of 32%, for the three months ended September 30, 2013, as compared to approximately $6.5 million for the three months ended September 30, 2012. During these respective periods, our total oil and natural gas production increased about 53% to 1,240 MBOE from 813 MBOE, including an increase in oil production of

104% to approximately 617 MBbl of oil from approximately 303 MBbl of oil. This increase in lease operating expenses was primarily attributable to the overall increase in oil production and the higher lifting costs associated with oil production between the comparable periods, as well as to the increased percentage of oil being produced, which was approximately 50% of total production by volume in the third quarter of 2013, compared to only 37% of total production by volume in the third quarter of 2012. Our lease operating expenses per unit of production decreased approximately 13% to $6.91 per BOE for the three months ended September 30, 2013, as compared to $7.98 per BOE for the three months ended September 30, 2012. The decrease in lease operating expenses on a unit of production basis between the two periods was attributable to the continued development of our Eagle Ford properties in South Texas. During 2012, we frequently produced new wells through rental test equipment monitored by 24-hour contract personnel until permanent facilities were in place, resulting in higher operating costs. As we drill new wells on properties where the production facilities are already in place or where they can be installed relatively quickly, we typically do not incur these types of expenses. Additional factors contributing to the decrease in lease operating expenses on a per unit basis were a decrease in workover costs primarily attributable to our initial use of gas lift rather than rod pumps on most of our recent Eagle Ford wells and a decrease in salt water disposal costs in the three months ended September 30, 2013, as compared to the three months ended September 30, 2012.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $4.4 million to $26.1 million, or an increase of about 21%, for the three months ended September 30, 2013, as compared to the three months ended September 30, 2012. On a unit-of-production basis, our depletion, depreciation and amortization expenses decreased to $21.06 per BOE for the three months ended September 30, 2013, or a decrease of about 21%, from $26.66 per BOE for the three months ended September 30, 2012. The increase in our depletion, depreciation and amortization expenses was attributable to the increase in our oil and natural gas production by approximately 53% to 1,240 MBOE from 813 MBOE during the respective periods, but was partially offset by the decrease in our depletion, depreciation and amortization rate on a per unit basis. Because we use the unit-of-production method for calculating depletion, depreciation and amortization, the impact of the increased production experienced in the three months ended September 30, 2013, as compared to the three months ended September 30, 2012, on our depletion, depreciation and amortization expenses was offset by the increase in our proved oil and natural gas reserves to 44.2 million BOE at September 30, 2013 from 20.9 million BOE at September 30, 2012. As a result of continued improvement in natural gas prices over the past year, we added approximately 100.0 Bcf (16.7 million BOE) of proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana to our estimated total proved reserves in the second and third quarters of 2013, which are reflected in our estimated total proved reserves at September 30, 2013. We had removed a large portion of these proved undeveloped natural gas reserves from our estimated total proved reserves at June 30, 2012 because the unweighted arithmetic average natural gas price of $3.146 per MMBtu had declined to a level that the natural gas volumes associated with almost all of our identified Haynesville shale well locations could no longer be classified as proved undeveloped reserves.

Accretion of asset retirement obligations. Our accretion of asset retirement obligations expenses increased by approximately $27,000 to approximately $86,000, or an increase of about 46%, for the three months ended September 30, 2013, as compared to the three months ended September 30, 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. No impairment to the net carrying value of our oil and natural gas properties on the unaudited condensed consolidated balance sheet, and no corresponding charge to the unaudited condensed consolidated statement of operations, resulting from a full-cost ceiling impairment was recorded during the three months ended September 30, 2013. At September 30, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $2.3 million. As a result, we recorded an impairment charge of $3.6 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $1.3 million, which is reflected in our operating expenses for the three months ended September 30, 2012. This impairment was primarily attributable to the continued decline in natural gas prices in the twelve-month period prior to September 30, 2012.

General and administrative. Our general and administrative expenses increased by approximately $2.0 million to $5.4 million, or an increase of about 57%, for the three months ended September 30, 2013, as compared to the three months ended September 30, 2012. The increase in our general and administrative expenses for the three months ended September 30, 2013, was primarily attributable to an increase in stock-based compensation costs of $1.3 million to $1.2 million for the three months ended September 30, 2013, as compared to $(0.1) million for the three months ended September 30, 2012. The remaining increase is due to additional payroll expenses associated with personnel added between the respective periods to support our increased operations. The increase in our stock-based compensation expense is attributable to the continued vesting of awards granted in 2012 and 2013, as well as the increased fair value of our liability-based stock options during the three months ended September 30, 2013. As a result of our increased production during the three months ended September 30, 2013, as compared to the three months ended September 30, 2012, our general and administrative expenses increased by only approximately 3% on a unit-of-production basis to $4.35 per BOE for the three months ended September 30, 2013, as compared to $4.23 per BOE for the three months ended September 30, 2012, which was primarily attributable to the increase in our stock-based compensation costs during the three months ended September 30, 2013.

Net loss on asset sales and inventory impairment. During the three months ended September 30, 2013 and September 30, 2012, we recorded no asset sales or impairment to our lease and well equipment inventory.

Interest expense. For the three months ended September 30, 2013, we incurred total interest expense of approximately $2.4 million. We capitalized approximately $0.4 million of our interest expense on certain qualifying projects for the three

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months ended September 30, 2013 and expensed the remaining $2.0 million to operations. For the three months ended September 30, 2012, we incurred total interest expense of approximately $0.5 million. We capitalized approximately $0.4 million of our interest expense on certain qualifying projects for the three months ended September 30, 2012 and expensed the remaining $0.1 million to operations. In September 2013, we used a portion of the net proceeds of our public equity offering to repay $130.0 million of outstanding borrowings under our Credit Agreement. At September 30, 2013, we had $145.0 million in borrowings and $0.3 million in letters of credit outstanding under our Credit Agreement.

Interest and other income. Our interest and other income increased by approximately $11,000 to approximately $66,000, or an increase of about 20%, for the three months ended September 30, 2013, as compared to the three months ended September 30, 2012. The increase in our interest and other income was due primarily to a slight increase in the transportation income we received from third parties during the third quarter of 2013, as compared to the third 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 $6.4 million at September 30, 2013 from approximately $4.4 million at September 30, 2012.

Total income tax provision. Based on our projections for the remainder of 2013, we anticipate incurring an 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 approximately $0.9 million for the three months ended September 30, 2013. The total income tax provision of approximately $2.6 million for the three months ended September 30, 2013 also includes approximately $1.7 million of deferred income taxes. We established a valuation allowance at September 30, 2012 and retained a full valuation allowance through June 30, 2013 due to uncertainties regarding the future realization of our net deferred tax assets. At September 30, 2013, our federal deferred tax liabilities exceeded our federal deferred tax assets and the valuation allowance on our federal deferred tax assets was reversed. We still retain a valuation allowance of approximately $0.7 million on our net state deferred tax assets at September 30, 2013, due to uncertainties regarding the future realization of these net state deferred tax assets. Our effective tax rate for the three months ended September 30, 2013 was 11.3%. Total income tax expense for the three months ended September 30, 2013 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily to the reversal of the valuation allowance of approximately $6.7 million on our federal deferred tax assets at September 30, 2013 and the impact of permanent differences between book and taxable income. The income tax provision recorded at September 30, 2012 reflected only deferred income taxes. We had a net loss for the three months ended September 30, 2012 and recorded a total income tax benefit of approximately $0.6 million.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

Production taxes and marketing. Our production taxes and marketing expenses increased by approximately $7.5 million to approximately $15.1 million, or an increase of approximately 99%, for the nine months ended September 30, 2013, as compared to $7.6 million for the nine months ended September 30, 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 93% during the nine months ended September 30, 2013, as compared to the nine months ended September 30, 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 nine months ended September 30, 2013 resulting from our drilling operations in the Eagle Ford shale in South Texas. Our total production was comprised of approximately 48% oil and 52% natural gas for the nine months ended September 30, 2013, as compared to approximately 34% oil and 66% natural gas for the nine months ended September 30, 2012. On a unit-of-production basis, our production taxes and marketing expenses increased by 46% to $4.74 per BOE for the nine months ended September 30, 2013, as compared to $3.25 per BOE for the nine months ended September 30, 2012. Production taxes on a unit-of-production basis on our oil and natural gas production in Texas are effectively higher than the production taxes on a unit-of-production basis on our production in Louisiana. As a result, the shift in our focus from the Haynesville shale in Northwest Louisiana and East Texas to the Eagle Ford shale in South Texas has also caused our production taxes on a unit-of-production basis to increase.

Lease operating expenses. Our lease operating expenses increased by approximately $12.1 million to approximately $29.6 million, or an increase of approximately 69%, for the nine months ended September 30, 2013, as compared to $17.5 million for the nine months ended September 30, 2012. During these respective periods, our total oil and natural gas production increased about 36% to 3.2 million BOE from 2.3 million BOE, including an increase of 93% in oil production to approximately 1,524 MBbl of oil from approximately 788 MBbl of oil. Our lease operating expenses per unit of production increased approximately 24% to $9.30 per BOE for the nine months ended September 30, 2013, as compared to $7.49 per BOE for the nine months ended September 30, 2012. This increase in lease operating expenses was primarily attributable to the overall increase in oil production and the higher lifting costs associated with oil production between the comparable periods, as well as to the increased percentage of oil being produced, which was 48% of total production by volume for the nine months ended September 30, 2013, as compared to only 34% of total production by volume for the nine months ended September 30, 2012.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $21.8 million to $74.6 million, or an increase of 41% for the nine months ended September 30, 2013, as compared to $52.8 million for the nine months ended September 30, 2012. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased slightly to $23.43 per BOE for the nine months ended September 30, 2013, or an increase of about 4%, from $22.58 per BOE for the nine months ended September 30, 2012. This increase in our depletion, depreciation and amortization expenses was attributable to the increase of approximately 36% in our total oil and natural gas production to 3.2 million BOE from 2.3 million 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 and East Texas. Because we use the unit-of-production method for calculating depletion, depreciation and amortization, the impact of the increased production experienced in the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012, on our depletion, depreciation and amortization expenses was offset by the increase in our proved oil and natural gas reserves to 44.2 million BOE at September 30, 2013 from 20.9 million BOE at September 30, 2012. As a result of continued improvement in natural gas prices over the past year, we added approximately 100.0 Bcf (16.7 million BOE) of proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana to our estimated total proved reserves in the second and third quarters of 2013, which are reflected in our estimated total proved reserves at September 30, 2013. We had removed a large portion of these proved undeveloped natural gas reserves from our estimated total proved reserves at June 30, 2012 because the unweighted arithmetic average natural gas price of $3.146 per MMBtu had declined to a level that the natural gas volumes associated with almost all of our identified Haynesville shale well locations could no longer be classified as proved undeveloped reserves.

Accretion of asset retirement obligations. Our accretion of asset retirement obligations expenses increased by approximately $78,000 to approximately $248,000, or an increase of about 46%, for the nine months ended September 30, 2013, as compared to approximately $170,000 for the nine months ended September 30, 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. No impairment to the net carrying value of our oil and natural gas properties on the unaudited condensed consolidated balance sheet, and no corresponding charge to the unaudited condensed consolidated statement of operations, resulting from a full-cost ceiling impairment was recorded during the three months ended September 30, 2013 or June 30, 2013. 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. This full-cost ceiling impairment of $21.2 million is reflected in our operating expenses for the nine months ended September 30, 2013. At June 30, 2012 and September 30, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $21.3 million and $2.3 million, respectively. As a result, we recorded an impairment charge of $33.2 million and $3.6 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $11.9 million and $1.3 million, respectively, which is reflected in our operating expenses for the three months ended September 30, 2012. This impairment was primarily attributable to the continued decline in natural gas prices in the twelve month period prior to September 30, 2012.

General and administrative. Our general and administrative expenses increased by $2.8 million to $14.1 million, or an increase of approximately 25%, for the nine months ended September 30, 2013, as compared to $11.3 million for the nine months ended September 30, 2012. The increase in our general and administrative expenses was primarily attributable to an increase in stock-based compensation costs of $3.0 million to $2.8 million for the nine months ended

September 30, 2013, as compared to $(0.2) million for the nine months ended September 30, 2012. The increase in our stock-based compensation expense was primarily attributable to the continued vesting of awards granted in 2012 and 2013, as well as the increased fair value of our liability-based stock options during the nine months ended September 30, 2013. The remaining increase is largely due to additional payroll expenses associated with personnel added between the respective periods to support our increased operations, some of which was offset by a $1.0 million decrease to our general and administrative expenses for the nine months ended September 30, 2013 as we allocated and capitalized a portion of our general and administrative expenses to the permanent production facilities being constructed on certain of our properties in the Eagle Ford shale in South Texas during the second quarter of 2013. Our general and administrative expenses decreased by approximately 8% on a unit-of-production basis to $4.44 per BOE for the nine months ended September 30, 2013, as compared to $4.84 for the nine months ended September 30, 2012, due to the increase of approximately 36% in our total oil and natural gas production to 3.2 million BOE from 2.3 million BOE during the respective periods.

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Net loss on asset sales and inventory impairment. During the nine months ended September 30, 2013, we recorded an impairment to some of our pipe held in inventory totaling approximately $192,000. During the nine months ended September 30, 2012, we sold some of our lease and well equipment inventory for approximately $60,000 less than the previously recorded fair value and recognized this loss upon the sale.

Interest expense. For the nine months ended September 30, 2013, we incurred total interest expense of approximately $6.1 million. We capitalized approximately $1.2 million of our interest expense on certain qualifying projects for the nine months ended September 30, 2013 and expensed the remaining $4.9 million to operations. For the nine months ended September 30, 2012, we incurred total interest expense of approximately $1.5 million. We capitalized approximately $1.0 million of our interest expense on certain qualifying projects for the nine months ended September 30, 2012 and expensed the remaining $0.5 million to operations. In September 2013, we used a portion of the net proceeds of our public equity offering to repay $130.0 million of outstanding borrowings under our Credit Agreement. At September 30, 2013, we had $145.0 million in borrowings and $0.3 million in letters of credit outstanding under our Credit Agreement.

Interest and other income. Our interest and other income increased by approximately $24,000 to approximately $181,000, or an increase of approximately 15%, for the nine months ended September 30, 2013, as compared to approximately $157,000 for the nine months ended September 30, 2012. The increase in our interest and other income was due primarily to a slight increase in the transportation income we received from third parties during the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012, although on the whole, this item is an insignificant component of our overall income. Our cash and certificates of deposit increased to approximately $6.4 million at September 30, 2013 from approximately $4.4 million at September 30, 2012.

Total income tax provision (benefit). Based on our projections for the remainder of 2013, we anticipate incurring an AMT liability for the year ending December 31, 2013, the proportionate share of which is recorded as the current income tax provision of approximately $1.0 million for the nine months ended September 30, 2013. The total income tax provision of approximately $2.6 million for the nine months ended September 30, 2013 also includes approximately $1.6 million of deferred income taxes. We established a valuation allowance at September 30, 2012 and retained a full valuation allowance through June 30, 2013 due to uncertainties regarding the future realization of our net deferred tax assets. At September 30, 2013, our federal deferred tax liabilities exceeded our federal deferred tax assets and the valuation allowance on our federal deferred tax assets was reversed. We still retain a valuation allowance of approximately $0.7 million on our net state deferred tax assets due to uncertainties regarding the future realization of these state deferred tax assets. Our effective tax rate for the nine months ended September 30, 2013 was 8.2%. Total income tax expense for the nine months ended September 30, 2013 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily to the reversal of the valuation allowance of approximately $6.7 million on our federal deferred tax assets at September 30, 2013 and the impact of permanent differences between book and taxable income. The income tax provision recorded at September 30, 2012 reflected only deferred income taxes. We had a net loss for the nine months ended September 30, 2012 and recorded a total income tax benefit of approximately $1.2 million.

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 oil and natural gas 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 September 30, 2013, we had cash and certificates of deposits totaling approximately $6.4 million, the borrowing base under our Credit Agreement was $350.0 million and we had $145.0 million of outstanding long-term borrowings and approximately $0.3 million in outstanding letters of credit. These borrowings bore interest at an effective interest rate of 4.0% per annum. From October 1, 2013 through November 7, 2013, we borrowed an additional $15.0 million under our Credit Agreement to finance a portion of our working capital requirements and capital expenditures and the acquisition of additional leasehold interests.

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. 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. On August 7, 2013, the borrowing base under the Credit Agreement was increased to $350.0 million from $280.0 million, based on the lenders' review of our proved oil and natural gas reserves at June 30, 2013. This August redetermination constituted the regularly scheduled November 1 redetermination. We may request one additional unscheduled redetermination of the borrowing base prior to the next scheduled redetermination. We expect 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.

On September 10, 2013, we completed a public offering of 9,775,000 shares of our common stock, including 1,275,000 shares issued pursuant to the underwriters' exercise of their option to purchase additional shares. After deducting underwriting discounts, commissions and direct offering costs totaling approximately $7.4 million, we received net proceeds of approximately $141.7 million. We intend to use the net proceeds from this offering primarily to fund a portion of our capital expenditures, including for the addition of a third rig to our previous two-rig drilling program, allowing us to operate two drilling rigs for the development of our acreage in the Eagle Ford shale play and one drilling rig for the exploration and development of our acreage in the Wolfcamp and Bone Spring plays in the Permian Basin. We also intend to use net proceeds from this offering to fund the acquisition of additional acreage in the Eagle Ford shale, the Permian Basin and the Haynesville shale and for other general working capital needs. Pending such uses, we used $130.0 million of the net proceeds to repay outstanding borrowings under our Credit Agreement, which amounts may be reborrowed in accordance with the terms of that facility. The remaining $11.7 million of the offering net proceeds was used to fund working capital requirements.

As a result of adding a third drilling rig to our drilling program, and in connection with our public equity offering, effective September 4, 2013, we increased our capital expenditure budget for 2013 from $325.0 million to $370.0 million. Our preliminary 2014 capital expenditure budget is estimated between $425.0 million and $450.0 million, and includes approximately $400.0 million for drilling and completing oil and natural gas exploration and development wells with the remainder allocated to lease acquisitions, seismic data, pipelines and other infrastructure. As a result of the receipt of the net proceeds of our September 2013 public equity offering, current availability and anticipated increases in the borrowing base under our Credit Agreement, and our anticipated increases in oil and natural gas production and related revenues, excluding any possible significant acquisitions, we expect to have sufficient future borrowing capacity under our Credit Agreement and cash flows from operations to fund our capital expenditure requirements for the remainder of 2013 and for 2014. 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, or should oil and natural gas prices decline substantially, we may require additional sources of financing, including through additional borrowings under our Credit Agreement (assuming availability under our borrowing base) or additional credit arrangements, potential joint ventures, the sale of assets or acreage 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.

Exploration and development activities are subject to a number of risks and uncertainties, which could cause these activities to be less successful than we anticipate and could impact our ability to sufficiently increase our reserves, cash flows from operations and borrowing base under our Credit Agreement. Although a significant portion of our anticipated cash flows from operations for the remainder of 2013 and for 2014 is expected to come from development activities on currently proved properties in the Eagle Ford shale in South Texas, these development activities may be less successful than we anticipate. Further, a portion of our anticipated cash flows from operations during the year ending December 31, 2014 is expected to come from exploration activities in the Eagle Ford shale and in the Wolfcamp and Bone Spring plays in the Permian Basin in Southeast New Mexico and West Texas, and these exploration activities may not be as successful as we anticipate. Additionally, our anticipated cash flows from operations are based upon current expectations of oil and natural gas prices for the remainder of 2013 and for 2014 and the hedges we currently have in place.

Our cash flows for the nine months ended September 30, 2013 and 2012 are presented below:

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	Nine Months Ended September 30,	
	2013	2012
(In thousands)	(Unaudited)	(Unaudited)
Net cash provided by operating activities	$127,192	$80,325
Net cash used in investing activities	(260,084)	(216,930)
Net cash provided by financing activities	137,127	130,499
Net change in cash	$4,235	$(6,106)
Adjusted EBITDA[(1)]	$142,931	$77,894

(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 $46.9 million to $127.2 million for the nine months ended September 30, 2013, as compared to net cash provided by operating activities of $80.3 million for the nine months ended September 30, 2012. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased to $137.0 million for the nine months ended September 30, 2013 from $77.3 million for the nine months ended September 30, 2012. This increase is primarily attributable to the 93% increase in our oil production to approximately 1,524 MBbl from approximately 788 MBbl during the respective periods as a result of our ongoing operations in the Eagle Ford shale. Changes in our operating assets and liabilities between September 30, 2012 and September 30, 2013 resulted in a net decrease of approximately $12.9 million in net cash provided by operating activities for the nine months ended September 30, 2013, as compared to the nine months ended September 30, 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 $43.2 million to $260.1 million for the nine months ended September 30, 2013 from $216.9 million for the nine months ended September 30, 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 nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012. Cash used for oil and natural gas properties capital expenditures for the nine months ended September 30, 2013 was primarily attributable to our operated drilling and completion activities in the Eagle Ford shale play in South Texas and the acquisition of additional leasehold interests, as well as to our initial operated drilling activities in the Permian Basin in Southeast New Mexico and West Texas.

As a result of adding a third drilling rig to our drilling program, and in connection with our public equity offering, effective September 4, 2013, we increased our capital expenditure budget for 2013 from $325.0 million to $370.0 million. At September 30, 2013 and at November 7, 2013, we were operating two drilling rigs on our leasehold acreage in South Texas and one drilling rig on our leasehold acreage in the Permian Basin in Southeast New Mexico and West Texas. We expect to operate two drilling rigs in the Eagle Ford shale in South Texas for the remainder of 2013 and throughout 2014. As a result of our recent acreage acquisitions in the Permian Basin in Southeast New Mexico and West Texas, the preliminary indications from our drilling program and the production results from nearby properties, we also intend to operate one contracted drilling rig in the Permian Basin for the remainder of 2013 and throughout 2014. As a result of adding a third drilling rig, we increased our 2013 capital expenditure budget to $370.0 million. We anticipate the acquisition of additional leasehold interests throughout the remainder of 2013, particularly in the Permian Basin 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 $370.0 million in capital for acquisition, exploration and development activities in 2013 as follows:

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	Amount (in millions)
Exploration, development drilling and completion costs	$295.0
Pipeline and infrastructure expenditures	25.0
Leasehold acquisition and 2-D and 3-D seismic data	50.0
Total	$370.0

At September 30, 2013, we had incurred approximately $253.1 million, or about 68%, of our 2013 capital expenditure budget of $370.0 million. Overall, at September 30, 2013, we are executing our 2013 capital expenditure program largely as planned and remain within our revised capital expenditure budget for 2013. While we have budgeted $370.0 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.

Our 2013 and 2014 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 $137.1 million for the nine months ended September 30, 2013, as compared to net cash provided by financing activities of $130.5 million for the nine months ended September 30, 2012. The net cash provided by financing activities for the nine months ended September 30, 2013 was primarily attributable to the total proceeds of our September 2013 public equity offering of $149.1 million and incremental borrowings under our Credit Agreement of $125.0 million, offset by the costs of the offering of $6.9 million paid during the period and by the repayment of $130.0 million in borrowings under our Credit Agreement during the period. The net cash provided by financing activities for the nine months ended September 30, 2012 was principally due to the total proceeds from our initial public offering of $146.5 million and incremental borrowings of $116.0 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 nine months ended September 30, 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.

(In thousands)	Three Months Ended June 30, 2013	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Unaudited Adjusted EBITDA Reconciliation to Net Income (Loss):					
Net income (loss)	$25,119	$20,105	$(9,197)	$29,720	$(12,073)
Interest expense	1,609	2,038	144	4,919	453
Total income tax provision (benefit)	32	2,563	(593)	2,641	(1,242)
Depletion, depreciation and amortization	20,234	26,127	21,680	74,593	52,799
Accretion of asset retirement obligations	80	86	59	248	170
Full-cost ceiling impairment	—	—	3,596	21,229	36,801
Unrealized (gain) loss on derivatives	(7,526)	9,327	12,993	6,626	1,149
Stock-based compensation expense	1,032	1,239	(51)	2,763	(223)
Net loss on asset sales and inventory impairment	192	—	—	192	60
Adjusted EBITDA	$40,772	$61,485	$28,631	$142,931	$77,894

(In thousands)	Three Months Ended June 30, 2013	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:					
Net cash provided by operating activities	$51,684	$43,280	$28,799	$127,192	$80,325
Net change in operating assets and liabilities	(12,553)	15,265	(500)	9,840	(3,072)
Interest expense	1,609	2,038	144	4,919	453
Current income tax provision	32	902	188	980	188
Adjusted EBITDA	$40,772	$61,485	$28,631	$142,931	$77,894

Our Adjusted EBITDA increased by approximately $65.0 million to approximately $142.9 million, or an increase of approximately 83%, for the nine months ended September 30, 2013, as compared to the nine months ended September 30, 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 nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012.

Credit Agreement

On September 28, 2012, we amended and restated our 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. 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 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 first quarter of 2013, the lenders completed their review of our proved oil and natural gas reserves at December 31, 2012, and on March 11, 2013, the borrowing base was increased from $215.0 million to $255.0 million. In connection with this borrowing base redetermination, the conforming borrowing base was increased to $220.0 million. At that time, we also amended the Credit Agreement to include Capital One, N.A., BMO Harris Financing, Inc. (Bank of Montreal) and Iberia Bank in our lending group, which also includes RBC, as administrative agent, Comerica Bank, Citibank, N.A., the Bank of Nova Scotia and SunTrust Bank. This March 11, 2013 redetermination constituted the regularly scheduled May 1 redetermination. In late April 2013, we requested an unscheduled redetermination of the borrowing base, and on June 4, 2013, the borrowing base was increased from $255.0 million to $280.0 million, and the conforming borrowing base was increased to $245.0 million.

On August 7, 2013, the borrowing base under the Credit Agreement was increased to $350.0 million and the conforming borrowing base was increased to $275.0 million. At that time, we amended the Credit Agreement to provide that the borrowing base will automatically be reduced to the conforming borrowing base at the earlier of (i) June 30, 2014 or (ii) concurrent with the issuance by us of senior unsecured notes in an amount greater than or equal to $10.0 million. This August redetermination constituted the regularly scheduled November 1 redetermination. We may request one additional unscheduled redetermination of our borrowing base prior to the next scheduled redetermination.

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.

On September 12, 2013, using a portion of the net proceeds from our public equity offering, we repaid $130.0 million of outstanding borrowings under the Credit Agreement. At September 30, 2013, we had $145.0 million in borrowings outstanding under the Credit Agreement and approximately $0.3 million in outstanding letters of credit issued pursuant to the Credit Agreement. At September 30, 2013, our outstanding borrowings bore interest at an effective interest rate of approximately 4.0% per annum. We expect to access future borrowings under our Credit Agreement to fund our remaining 2013 and our 2014 capital expenditure requirements in excess of amounts available from our operating cash flows. From October 1, 2013 through November 7, 2013, we borrowed an additional $15.0 million under the Credit Agreement to finance a portion of our working capital requirements and capital expenditures and the acquisition of additional leasehold interests. At November 7, 2013, we had $160.0 million in borrowings outstanding under the Credit Agreement and approximately $0.3 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 3.00% 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 4.00% 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 June 30, 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 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.

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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 September 30, 2013, we believe that we were in compliance with the terms of our Credit Agreement.

Off-Balance Sheet Arrangements

At September 30, 2013, we did not have any off-balance sheet arrangements.

Obligations and Commitments

We had the following material contractual obligations and commitments at September 30, 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, including letters of credit(1)	$145,340	$340	$—	$145,000	$—
Office lease	7,785	806	1,674	1,754	3,551
Non-operated drilling commitments(2)	16,704	16,704	—	—	—
Drilling rig contracts(3)	7,714	7,714	—	—	—
Asset retirement obligations	6,910	763	410	583	5,154
Gas processing and transportation agreement(4)	12,227	5,358	5,221	1,648	—
Total contractual cash obligations	$196,680	$31,685	$7,305	$148,985	$8,705

(1) At September 30, 2013, we had $145.0 million in revolving borrowings outstanding under our Credit Agreement and approximately $0.3 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 September 30, 2013, we had outstanding commitments to participate in the drilling and completion of various non-operated wells. Our working interests in these wells are typically small, and most of these wells were in progress at September 30, 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 $16.7 million at September 30, 2013, which we expect to incur within the next few months.

(3) From time to time, we enter into contracts with third parties for drilling rigs. These contracts establish daily rates for the drilling rigs and the term of our commitments for the drilling services to be provided, which are typically for one year or less. Should we elect to terminate a contract and if the drilling contractor were unable to secure work for the contracted drilling rigs or if the drilling contractor were unable to secure work for the contracted drilling 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 our drilling rig contracts were approximately $7.7 million at September 30, 2013.

(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 $12.2 million at September 30, 2013.

General Outlook and Trends

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For the nine months ended September 30, 2013, oil prices ranged from a high of approximately $110.53 per Bbl in early September to a low of approximately $86.68 per Bbl in mid-April, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. We realized an average oil price of $103.34 per Bbl ($102.24 per Bbl including realized losses from oil derivatives) for our oil production for the nine months ended September 30, 2013, as compared to $102.86 per Bbl ($104.25 per Bbl including realized gains from oil derivatives) for the nine months ended September 30, 2012. Subsequent to September 30, 2013, oil prices have decreased and at November 7, 2013, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date closed at $94.20 per Bbl as compared to $84.44 per Bbl at November 7, 2012.

We realized a weighted average oil price of $104.15 per Bbl for the three months ended September 30, 2013, which represented an uplift of about $5 per Bbl compared to NYMEX West Texas Intermediate oil prices during the third quarter of 2013, less transportation costs, as compared to an uplift of $10 to $12 per Bbl 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 second and third quarters of 2013, the differential between Louisiana Light Sweet and West Texas Intermediate oil prices narrowed significantly as compared to the first quarter of 2013, and subsequent to September 30, 2013, the differential between these two benchmark prices has continued to decrease. As a result, we may not realize similar, or any, uplifts to West Texas Intermediate oil prices in future periods. Additionally, we expect any oil production from our properties in the Permian Basin in Southeast New Mexico and West Texas will be sold on a West Texas Intermediate oil price index.

For the nine months ended September 30, 2013, natural gas prices ranged from a low of approximately $3.11 per MMBtu in early January to a high of approximately $4.41 per MMBtu in mid-April, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. We realized a weighted average natural gas price of $4.20 per Mcf ($4.35 per Mcf including realized gains from natural gas and NGL derivatives) for our natural gas production for the nine months ended September 30, 2013, as compared to $2.39 per Mcf ($3.47 per Mcf including realized gains from natural gas and NGL derivatives) for the nine months ended September 30, 2012. The weighted average price we received for our natural gas during the nine months ended September 30, 2013 was higher than the NYMEX Henry Hub natural gas price due to the NGL's present in the liquids-rich natural gas we produce from our Eagle Ford wells. Because we report our production volumes in two streams, oil and natural gas, including dry and liquids-rich natural gas, revenues associated with extracted natural gas liquids are included with our natural gas revenues, which has the effect of increasing the weighted average natural gas price realized on a per Mcf basis. Since the 2013 high in mid-April, natural gas prices have declined somewhat, and at November 7, 2013, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date closed at $3.52 per MMBtu, as compared to $3.58 per MMBtu at November 7, 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

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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 and in the Annual Report, there have been no changes to our market risk since December 31, 2012.

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 September 30, 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 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, 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 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, except for purity ethane, as stated on the “Mont Belvieu Spot Gas Liquids Prices: NON-TET prop” on the pricing date. The settlement price for purity ethane is the arithmetic average of any current month for delivery on the nearby month futures contracts as stated on the “Mont Belvieu Spot Gas Liquids Prices” 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

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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 September 30, 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 September 30, 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.

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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 September 30, 2013.

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil	10/01/2013 - 12/31/2013	20,000	85.00	102.25	$(131)
Oil	10/01/2013 - 12/31/2013	20,000	85.00	108.80	(22)
Oil	10/01/2013 - 12/31/2013	20,000	85.00	110.40	(13)
Oil	10/01/2013 - 12/31/2013	20,000	90.00	102.80	(105)
Oil	10/01/2013 - 12/31/2013	20,000	90.00	115.00	13
Oil	10/01/2013 - 06/30/2014	8,000	90.00	114.00	101
Oil	10/01/2013 - 06/30/2014	12,000	90.00	115.50	163
Oil	10/01/2013 - 12/31/2014	12,200	85.00	100.40	(249)
Oil	01/01/2014 - 12/31/2014	15,000	85.00	97.50	(399)
Oil	01/01/2014 - 12/31/2014	30,000	85.00	98.00	(767)
Oil	01/01/2014 - 12/31/2014	12,000	85.00	100.00	(154)
Oil	01/01/2014 - 12/31/2014	15,000	87.00	97.00	(357)
Oil	01/01/2014 - 12/31/2014	20,000	88.00	95.60	(593)
Oil	01/01/2014 - 12/31/2014	20,000	90.00	97.00	(294)
Oil	01/01/2014 - 12/31/2014	12,000	90.00	97.90	(97)
Oil	01/01/2014 - 12/31/2014	15,000	90.00	97.90	(124)
Oil	01/01/2014 - 12/31/2014	15,000	90.00	98.00	(135)
Oil	01/01/2014 - 12/31/2014	15,000	90.00	101.15	133
Total open oil costless collar contracts					(3,030)

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas	10/01/2013 - 12/31/2013	100,000	3.00	3.83	(16)
Natural Gas	10/01/2013 - 12/31/2013	100,000	3.00	4.95	1
Natural Gas	10/01/2013 - 12/31/2013	100,000	3.00	4.96	1
Natural Gas	10/01/2013 - 12/31/2013	150,000	3.00	4.24	(5)
Natural Gas	10/01/2013 - 12/31/2013	100,000	3.25	4.41	3
Natural Gas	10/01/2013 - 12/31/2013	100,000	3.25	4.44	3
Natural Gas	10/01/2013 - 12/31/2013	100,000	3.50	4.37	15
Natural Gas	10/01/2013 - 12/31/2013	80,000	3.75	4.57	54
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.00	5.15	(2)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.21	59
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.22	60
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.37	76
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.42	79
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.50	4.90	118
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.75	4.77	227
Natural Gas	01/01/2015 - 12/31/2015	200,000	3.75	5.04	331
Total open natural gas costless collar contracts					1,004

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Commodity	Calculation Period	Notional Quantity (Bbl/month)	Fixed Price ($/Bbl)	Fair Value of Liability (thousands)
Oil	10/01/2013 - 12/31/2013	10,000	90.20	(341)
Oil	10/01/2013 - 12/31/2013	10,000	90.65	(327)
Total open oil swap contracts				(668)

Commodity	Calculation Period	Notional Quantity (Gal/month)	Fixed Price ($/Gal)	Fair Value of Asset (Liability) (thousands)
Purity Ethane	10/01/2013 - 12/31/2013	110,000	0.335	28
Purity Ethane	10/01/2013 - 12/31/2013	110,000	0.355	35
Propane	10/01/2013 - 12/31/2013	53,000	0.953	(20)
Propane	10/01/2013 - 12/31/2013	106,000	0.960	(37)
Propane	10/01/2013 - 12/31/2013	53,000	1.001	(12)
Propane	10/01/2013 - 12/31/2013	150,000	1.103	16
Propane	01/01/2014 - 12/31/2014	116,000	0.950	(87)
Propane	01/01/2014 - 12/31/2014	116,000	1.003	8
Propane	01/01/2014 - 12/31/2014	60,000	1.015	13
Normal Butane	10/01/2013 - 12/31/2013	14,700	1.455	3
Normal Butane	10/01/2013 - 12/31/2013	14,700	1.560	8
Normal Butane	10/01/2013 - 12/31/2013	21,000	1.575	12
Normal Butane	10/01/2013 - 12/31/2013	117,000	1.575	63
Normal Butane	01/01/2014 - 12/31/2014	17,500	1.540	57
Normal Butane	01/01/2014 - 12/31/2014	45,500	1.550	143
Isobutane	10/01/2013 - 12/31/2013	7,000	1.515	2
Isobutane	10/01/2013 - 12/31/2013	7,000	1.625	4
Isobutane	10/01/2013 - 12/31/2013	43,500	1.675	34
Isobutane	10/01/2013 - 12/31/2013	23,000	1.675	18
Isobutane	01/01/2014 - 12/31/2014	22,000	1.640	87
Isobutane	01/01/2014 - 12/31/2014	37,000	1.640	156
Natural Gasoline	10/01/2013 - 12/31/2013	12,000	2.025	(3)
Natural Gasoline	10/01/2013 - 12/31/2013	12,000	2.085	—
Natural Gasoline	10/01/2013 - 12/31/2013	12,000	2.102	—
Natural Gasoline	10/01/2013 - 12/31/2013	36,000	2.105	1
Natural Gasoline	10/01/2013 - 12/31/2013	90,500	2.148	20
Natural Gasoline	01/01/2014 - 12/31/2014	30,000	1.970	(7)
Natural Gasoline	01/01/2014 - 12/31/2014	41,000	2.000	6
Total open NGL swap contracts				548
Total open derivative financial instruments				$(2,146)

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 Quarterly 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 September 30, 2013, to ensure that information required to be disclosed in the reports the Company files and submits

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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 third 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.

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Part II—OTHER INFORMATION

Item 1. Legal Proceedings

See the information under the heading "Legal Proceedings" of Part 1, Item 1 – "Financial Statements," "Note 10 – Commitments and Contingencies" of this Quarterly Report, 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.

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SIGNATURES

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

		MATADOR RESOURCES COMPANY
Date: November 8, 2013	By:	/s/ Joseph Wm. Foran Joseph Wm. Foran Chairman, President and Chief Executive Officer
Date: November 8, 2013	By:	/s/ David E. Lancaster David E. Lancaster Executive Vice President, Chief Operating Officer and Chief Financial Officer

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EXHIBIT INDEX

Exhibit Number	Description
10.1	Third Amendment to Third Amended and Restated Credit Agreement, dated as of August 7, 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 10.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).
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 September 30, 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.