Matador Resources Co
Form 10-Q
November 07, 2014

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, 2014

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 4, 2014, there were 73,362,360 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, 2014
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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, 2014	December 31, 2013
ASSETS		
Current assets		
Cash	$ 7,723	$ 6,287
Accounts receivable		
Oil and natural gas revenues	33,440	25,823
Joint interest billings	9,322	4,785
Other	1,517	1,066
Derivative instruments	3,929	19
Deferred income taxes	—	1,636
Lease and well equipment inventory	1,278	785
Prepaid expenses	1,846	1,771
Total current assets	59,055	42,172
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	1,469,633	1,090,656
Unproved and unevaluated	269,049	194,306
Other property and equipment	35,435	29,910
Less accumulated depletion, depreciation and amortization	(559,965)	(468,995)
Net property and equipment	1,214,152	845,877
Other assets		
Derivative instruments	1,278	173
Other assets	2,918	2,108
Total other assets	4,196	2,281
Total assets	$ 1,277,403	$ 890,330
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 15,420	$ 25,358
Accrued liabilities	119,361	63,987
Royalties payable	13,973	7,798
Derivative instruments	—	2,692
Deferred income taxes	802	—
Income taxes payable	2,969	404
Other current liabilities	95	88
Total current liabilities	152,620	100,327
Long-term liabilities		
Borrowings under Credit Agreement	250,000	200,000
Asset retirement obligations	10,751	7,309
Derivative instruments	9	253
Deferred income taxes	42,508	10,929
Other long-term liabilities	3,176	2,588
Total long-term liabilities	306,444	221,079
Commitments and contingencies (Note 10)		

Shareholders’ equity		
Common stock - $0.01 par value, 80,000,000 shares authorized; 74,683,934 and 66,958,867 shares issued; and 73,348,734 and 65,652,690 shares outstanding, respectively	747	670
Additional paid-in capital	734,065	548,935
Retained earnings	94,292	30,084
Treasury stock, at cost, 1,335,200 and 1,306,177 shares, respectively	(10,765)	(10,765)
Total shareholders’ equity	818,339	568,924
Total liabilities and shareholders’ equity	$ 1,277,403	$ 890,330

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,	
	2014	2013	2014	2013
Revenues				
Oil and natural gas revenues	$96,617	$81,868	$274,605	$199,367
Realized loss on derivatives	(701)	(1,165)	(5,458)	(519)
Unrealized gain (loss) on derivatives	16,293	(9,327)	7,950	(6,626)
Total revenues	112,209	71,376	277,097	192,222
Expenses				
Production taxes and marketing	8,617	6,559	23,739	15,107
Lease operating	13,691	8,569	34,747	29,608
Depletion, depreciation and amortization	35,143	26,127	90,970	74,593
Accretion of asset retirement obligations	130	86	371	248
Full-cost ceiling impairment	—	—	—	21,229
General and administrative	8,099	5,395	23,417	14,146
Total expenses	65,680	46,736	173,244	154,931
Operating income	46,529	24,640	103,853	37,291
Other income (expense)				
Net loss on asset sales and inventory impairment	—	—	—	(192)
Interest expense	(673)	(2,038)	(3,685)	(4,919)
Interest and other income	267	66	715	181
Total other expense	(406)	(1,972)	(2,970)	(4,930)
Income before income taxes	46,123	22,668	100,883	32,361
Income tax provision (benefit)				
Current	(156)	902	2,658	980
Deferred	16,660	1,661	34,017	1,661
Total income tax provision	16,504	2,563	36,675	2,641
Net income	$29,619	$20,105	$64,208	$29,720
Earnings per common share:				
Basic	$0.40	$0.35	$0.93	$0.53
Diluted	$0.40	$0.35	$0.92	$0.53
Weighted average common shares outstanding				
Basic	73,341	58,016	69,185	55,766
Diluted	74,028	58,152	69,879	55,889

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, 2014

	Common Stock		Additional Paid-In Capital	Retained Earnings	Treasury Stock		Total
	Shares	Amount			Shares	Amount	
Balance at January 1, 2014	66,959	$670	$548,935	$30,084	1,306	$(10,765)	$568,924
Issuance of common stock	7,500	75	181,800	—	—	—	181,875
Cost to issue equity	—	—	(590)	—	—	—	(590)
Common stock issued to Board and advisors	17	—	13	—	—	—	13
Stock options expense related to equity-based awards	—	—	1,666	—	—	—	1,666
Stock options exercised	2	—	6	—	—	—	6
Liability-based stock option awards settled	—	—	84	—	—	—	84
Restricted stock issued	205	2	(2)	—	—	—	—
Restricted stock forfeited	—	—	(18)	—	29	—	(18)
Restricted stock and restricted stock units expense	—	—	2,171	—	—	—	2,171
Current period net income	—	—	—	64,208	—	—	64,208
Balance at September 30, 2014	74,683	$747	$734,065	$94,292	1,335	$(10,765)	$818,339

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,	
	2014	2013
Operating activities		
Net income	$64,208	$29,720
Adjustments to reconcile net income to net cash provided by operating activities		
Unrealized (gain) loss on derivatives	(7,950)	6,626
Depletion, depreciation and amortization	90,970	74,593
Accretion of asset retirement obligations	371	248
Full-cost ceiling impairment	—	21,229
Stock-based compensation expense	4,665	2,763
Deferred income tax provision	34,017	1,661
Net loss on asset sales and inventory impairment	—	192
Changes in operating assets and liabilities		
Accounts receivable	(12,605)	(886)
Lease and well equipment inventory	(193)	198
Prepaid expenses	(74)	(2,148)
Other assets	(810)	(728)
Accounts payable, accrued liabilities and other current liabilities	(820)	(10,702)
Royalties payable	6,175	3,812
Advances from joint interest owners	—	(1,505)
Income taxes payable	2,565	980
Other long-term liabilities	(160)	1,139
Net cash provided by operating activities	180,359	127,192
Investing activities		
Oil and natural gas properties capital expenditures	(407,023)	(257,216)
Expenditures for other property and equipment	(2,906)	(3,058)
Purchases of certificates of deposit	—	(61)
Maturities of certificates of deposit	—	251
Net cash used in investing activities	(409,929)	(260,084)
Financing activities		
Repayments of borrowings under Credit Agreement	(180,000)	(130,000)
Borrowings under Credit Agreement	230,000	125,000
Proceeds from issuance of common stock	181,875	149,069
Cost to issue equity	(590)	(6,933)
Proceeds from stock options exercised	6	—
Taxes paid related to net share settlement of stock-based compensation	(285)	(9)
Net cash provided by financing activities	231,006	137,127
Increase in cash	1,436	4,235
Cash at beginning of period	6,287	2,095
Cash at end of period	$7,723	$6,330

Supplemental disclosures of cash flow information (Note 11)

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

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED
NOTE 1 - NATURE OF OPERATIONS
Matador Resources Company, a Texas corporation ("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.
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, 2013 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, 2014, consolidated results of operations for the three and nine months ended September 30, 2014 and 2013, consolidated changes in shareholders' equity for the nine months ended September 30, 2014 and consolidated cash flows for the nine months ended September 30, 2014 and 2013. Amounts as of December 31, 2013 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 interim unaudited condensed consolidated financial statements are based on a number of significant estimates, including accruals for oil and natural gas revenues, accrued assets and liabilities primarily related to oil and natural gas operations, stock-based compensation, valuation of derivative instruments and oil and natural gas reserves. The estimates of oil and natural gas reserves quantities and future net cash flows are the basis for the calculations of depletion and impairment of oil and natural gas properties, as well as estimates of asset retirement obligations and certain tax accruals. While the Company believes its estimates are reasonable, changes in facts and assumptions or the discovery of new information may result in revised estimates. Actual results could differ from these estimates.
Property and Equipment
The Company uses the full-cost method of accounting for its investments in oil and natural gas properties. Under this method of accounting, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing the Company's activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on

undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects and certain general and administrative expenses directly related to acquisition, exploration and development activities, but do not include any costs related to production, selling or general corporate administrative activities. The Company capitalized approximately $1.5 million and $0.9 million of its general and administrative costs for the three months ended September 30, 2014 and 2013, respectively. The Company capitalized approximately $0.8 million and $0.4 million of its interest expense for the three months ended September 30, 2014 and 2013, respectively. The Company capitalized approximately $4.3 million and $2.3 million of its general and administrative

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

costs for the nine months ended September 30, 2014 and 2013, respectively. The Company capitalized approximately $2.2 million and $1.2 million of its interest expense for the nine months ended September 30, 2014 and 2013, 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.” The cost center ceiling is defined as the sum of:

(a) the present value, discounted at 10%, of future net revenues of proved oil and natural gas reserves, reduced by the estimated costs of developing these 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.

Any excess of the Company’s net capitalized costs above the cost center ceiling as described above is charged to operations as a full-cost ceiling impairment. The need for a full-cost ceiling impairment is required to be assessed on a quarterly basis. 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 upon the quantities of proved reserves, the estimation of which requires substantial judgment. The associated commodity prices and applicable discount rate used in these estimates are in accordance with guidelines established by the SEC. 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. Future net revenues are calculated using prices that represent the arithmetic averages of first-day-of-the-month oil and natural gas prices for the previous 12-month period and dictate that a 10% discount factor be used. For the period from October 2013 through September 2014, these average oil and natural gas prices were $95.56 per barrel (“Bbl”) and $4.236 per million British thermal units (“MMBtu”), respectively. 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, 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, 2014 and 2013, 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, 2014, 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, 2014. 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 related to the full-cost ceiling limitation at 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.

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. Changes in oil and natural gas production rates, oil and natural gas prices, reserves estimates, future development costs and other factors will determine the Company's actual ceiling test computation and impairment analyses in future periods.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

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

Earnings (Loss) Per Common Share

The Company reports basic earnings (loss) 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.

The following table sets forth the computation of diluted weighted average common shares outstanding for the three and nine months ended September 30, 2014 and 2013 (in thousands).

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Weighted average common shares outstanding				
Basic	73,341	58,016	69,185	55,766
Dilutive effect of options and restricted stock units	687	136	694	123
Diluted weighted average common shares outstanding	74,028	58,152	69,879	55,889

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

Revenue from Contracts with Customers. In May 2014, the FASB issued Accounting Standards Update, or ASU, 2014-09, Revenue from Contracts with Customers (Topic 606), which specifies how and when to recognize revenue. This standard requires expanded disclosures surrounding revenue recognition and is intended to improve, and converge with international standards, the financial reporting requirements for revenue from contracts with customers. ASU 2014-09 will become effective for fiscal years beginning after December 15, 2016, i.e., in the Company’s first fiscal quarter of 2017. The Company is currently evaluating the impact, if any, of the adoption of this ASU on its consolidated financial statements.

NOTE 3 - COMMON STOCK

On May 29, 2014, the Company completed a public offering of 7,500,000 shares of its common stock. After deducting direct offering costs totaling approximately $0.6 million, the Company received net proceeds of approximately $181.3 million. The Company used a portion of the net proceeds to repay $180.0 million in outstanding borrowings under its Credit Agreement (see Note 5), which amounts may be reborrowed in accordance with the terms of that facility. The remaining $1.3 million of the offering net proceeds was used to fund working capital requirements.

On October 31, 2014, Matador’s board of directors canceled all of the shares of treasury stock outstanding as of September 30, 2014. These shares were restored to the status of authorized but unissued shares of the common stock of the Company.

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

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, 2014 (in thousands).

Beginning asset retirement obligations	$7,484
Liabilities incurred during period	1,906
Liabilities settled during period	(22)
Revisions in estimated cash flows	1,552
Accretion expense	371
Ending asset retirement obligations	11,291
Less: current asset retirement obligations[1]	(540)
Long-term asset retirement obligations	$10,751

(1) Included in accrued liabilities in the Company's unaudited condensed consolidated balance sheet at September 30, 2014.

NOTE 5 - REVOLVING CREDIT AGREEMENT

On September 28, 2012, the Company entered into a third amended and restated credit agreement with the lenders party thereto (the "Credit Agreement"), which increased the maximum facility amount from $400.0 million to $500.0 million. The Credit Agreement matures December 29, 2016. MRC Energy Company, which is a subsidiary of the Company and directly or indirectly owns the ownership interests in the Company's other operating subsidiaries, is the borrower under the Credit Agreement. Borrowings are secured by mortgages on substantially all of the Company's proved oil and natural gas properties and by the equity interests of certain 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 certain 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 2014, the lenders completed their review of the Company's estimated total proved oil and natural gas reserves at December 31, 2013, and as a result, on March 12, 2014, the borrowing base under the Credit Agreement was increased to $385.0 million, and the conforming borrowing base was increased to $310.0 million. At that time, the Company amended the Credit Agreement to, among other things, provide that the borrowing base will automatically be reduced to the conforming borrowing base at the earlier of (i) June 30, 2015 or (ii) concurrent with the issuance by the Company of senior unsecured notes in an amount greater than or equal to $10.0 million. The Credit Agreement was also amended to eliminate the current ratio covenant and to increase the debt to EBITDA ratio covenant, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, to 4.25 or less. Furthermore, the interest rate charged to the Company based on its outstanding level of borrowings was reduced by 0.25% across the borrowing grid as a result of this amendment. This March 2014 redetermination constituted the regularly scheduled May 1 redetermination. During the third quarter of 2014, the lenders completed their review of the Company's estimated total proved oil and natural gas reserves at July 31, 2014, and as a result, on September 5, 2014, the borrowing base under the Credit Agreement was increased to $450.0 million, and the conforming borrowing base was increased to $375.0 million. This September 2014 redetermination constituted the regularly scheduled November 1 redetermination. The Company expects additional increases to the borrowing base primarily as a result of

anticipated increases in its proved oil and natural gas reserves, and particularly its proved developed oil and natural gas reserves.
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. Total deferred loan costs were $2.0 million at September 30, 2014, and these costs are being amortized over the term of the agreement, which approximates the amortization of these costs using the effective interest method. 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

NOTE 5 - REVOLVING CREDIT AGREEMENT - Continued

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.

On May 29, 2014, using a portion of the net proceeds from its public equity offering, the Company repaid $180.0 million of its outstanding borrowings under the Credit Agreement. At September 30, 2014, the Company had $250.0 million in borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. For the three months ended September 30, 2014, the Company's outstanding borrowings bore interest at an effective interest rate of approximately 2.9% per annum. From October 1, 2014 through November 5, 2014, the Company borrowed an additional $40.0 million under the Credit Agreement to finance a portion of its working capital requirements and capital expenditures and the acquisition of additional leasehold interests. At November 5, 2014, the Company had $290.0 million in borrowings outstanding under the Credit Agreement and approximately $0.6 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, (ii) the Federal Funds Effective Rate (as defined in the Credit Agreement) on such day, plus 0.50% or (iii) the daily adjusting LIBOR rate (as defined in the Credit Agreement) plus 1.0% plus, in each case, an amount from 0.50% to 2.75% of such outstanding loan depending on the level of borrowings under the agreement. If the Company borrows funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (i) the quotient obtained by dividing (A) the LIBOR rate by (B) a percentage equal to 100% minus the maximum rate during such interest calculation period at which Royal Bank of Canada ("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 1.50% to 3.75% 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, if any, as interest expense and in its interest rate calculations and related disclosures. The Credit Agreement requires the Company to maintain a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.25 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 the Company's assets;
- enter into commodity hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates; and
- engage in certain asset dispositions, including a sale of all or substantially all of the Company's assets.

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

- failure to pay any principal or interest on the outstanding borrowings or any reimbursement obligation under any letter of credit when due or any fees or other amounts within certain grace periods;
-

failure to perform or otherwise comply with the covenants and obligations in the Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;

- bankruptcy or insolvency events involving the Company or its subsidiaries; and

NOTE 5 - REVOLVING CREDIT AGREEMENT - Continued

- a change of control, as defined in the Credit Agreement.

During the second quarter of 2014, Bank of America, N.A. replaced Citibank, N.A. as a lender under the Credit Agreement. At September 30, 2014, the Company believes that it was in compliance with the terms of the Credit Agreement.

NOTE 6 - INCOME TAXES

The Company had effective tax rates of 35.8% and 36.4% for the three and nine months ended September 30, 2014, respectively. Total income tax expense for the three and nine months ended September 30, 2014 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due to the impact of permanent differences between book and taxable income. Based upon its projections for the remainder of 2014 and 2013, the Company anticipated incurring a small alternative minimum tax ("AMT") liability for the years ending December 31, 2014 and 2013, the proportionate shares of which were recorded as the current income tax provision for the three and nine months ended September 30, 2014 and 2013. The Company had effective tax rates 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 rate 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, and the impact of permanent differences between book and taxable income.

NOTE 7 - STOCK-BASED COMPENSATION

In February and March 2014, the Company granted awards of options to certain of its employees to purchase 49,721 shares of the Company's common stock at an exercise price of $19.71, 224,962 shares at an exercise price of $23.40 and 75,247 shares at an exercise price of $22.66. The fair value of these awards was approximately $3.3 million. The Company also granted awards of 150,854 shares of restricted stock to certain of its employees in February and March 2014. The fair value of these restricted stock awards was approximately $3.4 million. All of these awards vest over a term of three or four years.

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 unrealized loss. The fair value of the Company's derivative financial instruments is determined using industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. RBC, Comerica Bank, The Bank of Nova Scotia, BMO Harris Financing (Bank of Montreal) and SunTrust Bank (or affiliates thereof) were the counterparties for the Company's commodity derivatives at September 30, 2014. 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.

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 settlement date of that contract period. When the settlement

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

price is below the price floor established by one or more of these collars, the Company receives from the counterparty an amount equal to the difference between the settlement price and the price floor multiplied by the contract natural gas volume. When the settlement price is above the price ceiling established by one or more of these collars, the Company pays to the counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract natural gas volume.

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

At September 30, 2014, 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 2014 and 2015.

At September 30, 2014, the Company had various swap contracts open and in place to mitigate its exposure to 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 2014 and 2015.

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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 is a summary of the Company's open costless collar contracts for oil and natural gas and open swap contracts for NGL at September 30, 2014.

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil	10/01/2014 - 12/31/2014	10,000	85.00	100.55	18
Oil	10/01/2014 - 12/31/2014	12,200	85.00	100.40	22
Oil	10/01/2014 - 12/31/2014	15,000	85.00	97.50	19
Oil	10/01/2014 - 12/31/2014	30,000	85.00	98.00	40
Oil	10/01/2014 - 12/31/2014	12,000	85.00	100.00	21
Oil	10/01/2014 - 12/31/2014	15,000	87.00	97.00	35
Oil	10/01/2014 - 12/31/2014	20,000	88.00	95.60	53
Oil	10/01/2014 - 12/31/2014	20,000	90.00	97.00	106
Oil	10/01/2014 - 12/31/2014	12,000	90.00	97.90	66
Oil	10/01/2014 - 12/31/2014	15,000	90.00	97.90	83
Oil	10/01/2014 - 12/31/2014	15,000	90.00	98.00	83
Oil	10/01/2014 - 12/31/2014	15,000	90.00	101.15	90
Oil	10/01/2014 - 12/31/2014	10,000	90.00	103.75	61
Oil	10/01/2014 - 12/31/2014	10,000	90.00	103.88	62
Oil	10/01/2014 - 12/31/2014	10,000	90.00	104.15	62
Oil	01/01/2015 - 12/31/2015	20,000	80.00	100.00	290
Oil	01/01/2015 - 12/31/2015	20,000	80.00	101.00	323
Oil	01/01/2015 - 12/31/2015	20,000	83.00	96.12	315
Oil	01/01/2015 - 12/31/2015	20,000	83.00	97.00	343
Oil	01/01/2015 - 12/31/2015	20,000	85.00	99.00	624
Oil	01/01/2015 - 12/31/2015	20,000	85.00	100.00	645
Oil	01/01/2015 - 12/31/2015	20,000	85.00	105.10	798
Total open oil costless collar contracts					4,159

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

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas	10/01/2014 - 12/31/2014	100,000	3.00	5.15	(3)
Natural Gas	10/01/2014 - 12/31/2014	100,000	3.25	5.21	(1)
Natural Gas	10/01/2014 - 12/31/2014	100,000	3.25	5.22	(1)
Natural Gas	10/01/2014 - 12/31/2014	100,000	3.25	5.37	—
Natural Gas	10/01/2014 - 12/31/2014	100,000	3.25	5.42	—
Natural Gas	10/01/2014 - 12/31/2014	100,000	3.50	4.90	(2)
Natural Gas	10/01/2014 - 12/31/2014	100,000	3.75	4.75	2
Natural Gas	10/01/2014 - 12/31/2014	100,000	3.75	4.77	2
Natural Gas	10/01/2014 - 12/31/2014	100,000	4.00	4.60	12
Natural Gas	10/01/2014 - 12/31/2015	100,000	3.75	4.36	6
Natural Gas	10/01/2014 - 12/31/2015	100,000	3.75	4.45	43
Natural Gas	01/01/2015 - 03/31/2015	200,000	4.00	4.84	45
Natural Gas	01/01/2015 - 12/31/2015	100,000	3.75	4.60	96
Natural Gas	01/01/2015 - 12/31/2015	100,000	3.75	4.65	116
Natural Gas	01/01/2015 - 12/31/2015	200,000	3.75	5.04	378
Natural Gas	01/01/2015 - 12/31/2015	100,000	3.75	5.34	225
Total open natural gas costless collar contracts					918

Commodity	Calculation Period	Notional Quantity (Gal/month)	Fixed Price ($/Gal)	Fair Value of Asset (Liability) (thousands)
Propane	10/01/2014 - 12/31/2014	116,000	0.950	(45)
Propane	10/01/2014 - 12/31/2014	116,000	1.003	(16)
Propane	10/01/2014 - 12/31/2014	60,000	1.015	(6)
Propane	10/01/2014 - 12/31/2014	84,000	1.143	24
Propane	10/01/2014 - 12/31/2014	68,000	1.150	21
Propane	01/01/2015 - 12/31/2015	150,000	1.000	(48)
Propane	01/01/2015 - 12/31/2015	100,000	1.030	4
Propane	01/01/2015 - 12/31/2015	68,000	1.073	37
Normal Butane	10/01/2014 - 12/31/2014	17,500	1.540	21
Normal Butane	10/01/2014 - 12/31/2014	45,500	1.550	45
Isobutane	10/01/2014 - 12/31/2014	22,000	1.640	27
Isobutane	10/01/2014 - 12/31/2014	37,000	1.640	56
Natural Gasoline	10/01/2014 - 12/31/2014	30,000	1.970	(5)
Natural Gasoline	10/01/2014 - 12/31/2014	41,000	2.000	6
Total open NGL swap contracts				121
Total open derivative financial instruments				$5,198

These derivative financial instruments are subject to master netting arrangements within specific commodity types, i.e., oil, natural gas and NGL, by counterparty. Derivative financial instruments with Counterparty A are not subject to master netting across commodity types, while derivative financial instruments with Counterparties B, C, D and E 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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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

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, 2014 (in thousands).

Derivative Instruments	Gross amounts of recognized assets	Gross amounts netted in the condensed consolidated balance sheet	Net amounts of assets presented in the condensed consolidated balance sheet	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current assets	$1,425	$(534)	$891	$—
Other assets	568	(243)	325	—
Counterparty B				
Current assets	1,369	(556)	813	—
Other assets	461	(233)	228	—
Counterparty C				
Current assets	2,991	(1,568)	1,423	—
Other assets	1,060	(620)	440	—
Counterparty D				
Current assets	9	(8)	1	—
Other assets	—	—	—	—
Counterparty E				
Current assets	966	(165)	801	—
Other assets	367	(82)	285	—
Total	$9,216	$(4,009)	$5,207	$—

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NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

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, 2014 (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	$534	$(534)	$—	$—
Other liabilities	243	(243)	—	—
Counterparty B				
Current liabilities	556	(556)	—	—
Other liabilities	233	(233)	—	—
Counterparty C				
Current liabilities	1,568	(1,568)	—	—
Other liabilities	629	(620)	9	—
Counterparty D				
Current liabilities	8	(8)	—	—
Other liabilities	—	—	—	—
Counterparty E				
Current liabilities	165	(165)	—	—
Other liabilities	82	(82)	—	—
Total	$4,018	$(4,009)	$9	$—

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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 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, 2013 (in thousands).

Derivative Instruments	Gross amounts of recognized assets	Gross amounts netted in the condensed consolidated balance sheet	Net amounts of assets presented in the condensed consolidated balance sheet	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current assets	$1,746	$(1,746)	$—	$—
Other assets	—	—	—	—
Counterparty B				
Current assets	1,371	(1,371)	—	—
Other assets	841	(668)	173	—
Counterparty C				
Current assets	2,886	(2,873)	13	—
Other assets	1,046	(1,046)	—	—
Counterparty D				
Current assets	6	—	6	—
Other assets	—	—	—	—
Total	$7,896	$(7,704)	$192	$—

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, 2013 (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	$2,550	$(1,746)	$804	$—
Other liabilities	—	—	—	—
Counterparty B				
Current liabilities	2,136	(1,371)	765	—
Other liabilities	668	(668)	—	—
Counterparty C				
Current liabilities	3,996	(2,873)	1,123	—
Other liabilities	1,299	(1,046)	253	—
Counterparty D				

Current liabilities	—	—	—	—
Other liabilities	—	—	—	—
Total	$10,649	$(7,704)	$2,945	$—

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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 unaudited condensed consolidated statements of operations for the periods presented (in thousands). These derivative financial instruments are not designated as hedging instruments.

		Three Months Ended September 30,		Nine Months Ended September 30,	
Type of Instrument	Location in Condensed Consolidated Statement of Operations	2014	2013	2014	2013
Derivative Instrument					
Oil	Revenues: Realized loss on derivatives	$(816)	$(1,519)	$(4,523)	$(1,984)
Natural Gas	Revenues: Realized gain (loss) on derivatives	19	161	(757)	790
NGL	Revenues: Realized gain (loss) on derivatives	96	193	(178)	675
Realized loss on derivatives		(701)	(1,165)	(5,458)	(519)
Oil	Revenues: Unrealized gain (loss) on derivatives	14,106	(8,132)	6,359	(6,818)
Natural Gas	Revenues: Unrealized gain (loss) on derivatives	1,933	57	1,362	(132)
NGL	Revenues: Unrealized gain (loss) on derivatives	254	(1,252)	229	324
Unrealized gain (loss) on derivatives		16,293	(9,327)	7,950	(6,626)
Total		$15,592	$(10,492)	$2,492	$(7,145)

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 with industry standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument and 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, 2014 and December 31, 2013, the carrying values reported on the unaudited condensed consolidated balance sheets for accounts receivable, prepaid expenses, accounts payable, accrued liabilities, royalties payable, income taxes payable and other current liabilities approximate their fair values due to their short-term maturities.

At September 30, 2014 and December 31, 2013, 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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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 9 - FAIR VALUE MEASUREMENTS - Continued

The following tables summarize the valuation of the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis in accordance with the classifications provided above as of September 30, 2014 and December 31, 2013 (in thousands).

	Fair Value Measurements at September 30, 2014 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Oil, natural gas and NGL derivatives	$—	$5,207	$—	$5,207
Oil, natural gas and NGL derivatives	—	(9)	—	(9)
Total	$—	$5,198	$—	$5,198

	Fair Value Measurements at December 31, 2013 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Oil, natural gas and NGL derivatives	$—	$192	$—	$192
Oil, natural gas and NGL derivatives	—	(2,945)	—	(2,945)
Total	$—	$(2,753)	$—	$(2,753)

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

The Company accounts for additions and revisions to asset retirement obligations and lease and well equipment inventory when adjusted for impairment at fair value on a non-recurring basis and has determined that these fair value measurements should be classified at Level 3. 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, 2014 and December 31, 2013 (in thousands).

	Fair Value Measurements at September 30, 2014 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$—	$—	$(3,458)	$(3,458)
Total	$—	$—	$(3,458)	$(3,458)

	Fair Value Measurements at December 31, 2013 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$—	$—	$(1,470)	$(1,470)
Total	$—	$—	$(1,470)	$(1,470)

No impairment to any equipment was recorded during the three months ended September 30, 2014 and December 31, 2013.

NOTE 10 - COMMITMENTS AND CONTINGENCIES

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 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. During certain prior periods, the Company had an immaterial natural gas deficiency, and the counterparty to this agreement waived the deficiency fee. The Company's remaining aggregate undiscounted minimum commitments under this agreement are $6.9 million at September 30, 2014. The Company paid $1.5 million and $2.0 million in processing and transportation fees under this agreement during the three months ended September 30, 2014 and 2013, respectively, and $4.3 million and $3.8 million during the nine months ended September 30, 2014 and 2013, respectively.

Other Commitments

The Company does not own or operate its own drilling rigs, but instead enters into contracts with third parties for such 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 have typically been for one year or less, although the Company has recently begun to enter into longer-term contracts in order to secure new drilling rigs equipped with the latest technology in plays that are experiencing heavy demand for drilling rigs. The Company would incur a termination obligation if the Company elected to terminate a contract and the drilling contractor were unable to secure work for the contracted drilling rigs or if the drilling contractor were unable to secure replacement 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's undiscounted minimum outstanding aggregate termination obligations under its drilling rig contracts were approximately $57.9 million at September 30, 2014.

At September 30, 2014, 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 undiscounted minimum outstanding aggregate commitments for its participation in these wells of approximately $21.9 million at September 30, 2014, which it expects to incur within the next few months.

Legal Proceedings

The Company is a defendant in several lawsuits encountered in the ordinary course of its business. While the ultimate outcome and impact to the Company cannot be predicted with certainty, 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.

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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, 2014 and December 31, 2013 (in thousands).

	September 30, 2014	December 31, 2013
Accrued evaluated and unproved and unevaluated property costs	$97,101	$52,605
Accrued support equipment and facilities costs	2,488	—
Accrued stock-based compensation	—	56
Accrued lease operating expenses	9,870	6,251
Accrued interest on borrowings under Credit Agreement	158	141
Accrued asset retirement obligations	540	175
Accrued partners' share of joint interest charges	3,648	1,173
Other	5,556	3,586
Total accrued liabilities	$119,361	$63,987

Supplemental Cash Flow Information
The following table provides supplemental disclosures of cash flow information for the nine months ended September 30, 2014 and 2013 (in thousands).

	Nine Months Ended September 30,	
	2014	2013
Cash paid for interest expense, net of amounts capitalized	$3,667	$2,110
Asset retirement obligations related to mineral properties	3,305	889
Asset retirement obligations related to support equipment and facilities	132	4
Increase (decrease) in liabilities for oil and natural gas properties capital expenditures	43,692	(6,288)
Increase (decrease) in liabilities for support equipment and facilities	2,488	(1,100)
Increase in liabilities for accrued cost to issue equity	—	456
Issuance of restricted stock units for Board and advisor services	313	186
Issuance of common stock for advisor services	13	25
Stock-based compensation expense recognized as liability	789	715
Transfer of inventory from oil and natural gas properties	300	201

NOTE 12 - SUBSIDIARY GUARANTORS
Matador filed a registration statement on Form S-3 with the SEC in 2013, which became effective on May 9, 2013, and a registration statement on Form S-3 with the SEC in 2014, which became effective upon filing on May 22, 2014, registering, in each case, among other securities, senior and subordinated debt securities. Certain subsidiaries of Matador (the "Guarantor Subsidiaries") are co-registrants with Matador on each Form S-3, and the registration statements register guarantees of debt securities by the Guarantor Subsidiaries. As of September 30, 2014, the Guarantor Subsidiaries are 100% owned by Matador and any guarantees by the Guarantor Subsidiaries will be full and unconditional (except for customary release provisions). Matador has no significant assets or operations independent of the Guarantor Subsidiaries, and there are no significant restrictions upon the ability of the Guarantor Subsidiaries to distribute funds to Matador. In the event that more than one of the Guarantor Subsidiaries provide guarantees of any debt securities issued by Matador, such guarantees will constitute joint and several obligations. As of September 30, 2014, the Company had no outstanding debt securities.

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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 related notes thereto contained herein and in our Annual Report on Form 10-K for the year ended December 31, 2013 (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 the section entitled “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.

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 Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. 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,” “inter “may,” “might,” “potential,” “predict,” “project,” “should” or other similar words.

By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: changes in oil or natural gas prices, the success of our drilling program, the timing and amount of planned capital expenditures, having sufficient cash flow from operations together with available borrowing capacity under our revolving credit facility, 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, availability of acquisitions, 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

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with 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.

Third Quarter and Year-to-Date Highlights

Our total oil equivalent production for the third quarter of 2014 was 1.5 million BOE. Our average daily oil equivalent production for the third quarter of 2014 was 16,096 BOE per day, of which 9,123 Bbl per day, or 57%, was oil and 41.8 MMcf per day, or 43%, was natural gas. These quarterly production results were the best in our Company’s history. Our total oil production for the third quarter of 2014 of 839,000 Bbl and our average daily oil production of 9,123 Bbl per day were also record quarterly results. We achieved these results despite having as much as 15 to 20% of our total production capacity shut in or restricted at various times during the third quarter while offsetting wells were being drilled and completed and pipeline connections were being made. For the nine months ended September 30, 2014, our total oil equivalent production was 4.0 million BOE, averaging 14,490 BOE per day, and our total oil production was 2.3 million Bbl, averaging 8,432 Bbl per day. These results were also the best reported for any nine-month period in our Company’s history.

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During the third quarter of 2014, our oil and natural gas revenues were $96.6 million, an increase of 18% from oil and natural gas revenues of $81.9 million during the third quarter of 2013. This increase was primarily attributable to the 36% increase in our oil production to 839,000 Bbl in the third quarter of 2014, as compared to 617,000 Bbl produced in the third quarter of 2013. This increase in oil production is primarily attributable to faster drilling operations and better completions in the Eagle Ford shale as well as better-than-expected initial production contributions from newly drilled wells in the Permian Basin. For the nine months ended September 30, 2014, our oil and natural gas revenues were $274.6 million, an increase of 38% from oil and natural gas revenues of $199.4 million for the first nine months of 2013. For the three months ended September 30, 2014, our Adjusted EBITDA was $66.8 million, an increase of 9% from Adjusted EBITDA of $61.5 million during the three months ended September 30, 2013. For the nine months ended September 30, 2014, our Adjusted EBITDA was $192.6 million, an increase of 35% from $142.9 million during the nine months ended September 30, 2013. These oil and natural gas revenues and Adjusted EBITDA values for the nine months ended September 30, 2014 were the best reported for any nine-month period in our Company's history. 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 "— Liquidity and Capital Resources — Non-GAAP Financial Measures." For more information regarding our financial results for 2014, see "— Results of Operations" below.

On September 5, 2014, the borrowing base under our revolving credit facility increased from $385.0 million to $450.0 million based on our lenders' review of our proved oil and natural gas reserves at July 31, 2014. At September 30, 2014, the Company had borrowings outstanding of $250.0 million and $0.6 million in letters of credit issued under the credit facility. From October 1, 2014 through November 5, 2014, the Company borrowed an additional $40.0 million under its revolving credit facility to finance a portion of its working capital requirements and capital expenditures and the acquisition of additional leasehold interests. At November 5, 2014, the Company had $290.0 million in borrowings outstanding under its revolving credit facility and approximately $0.6 million in outstanding letters of credit issued pursuant to such facility. We expect future increases to our borrowing base as the result of anticipated increases in our proved oil and natural gas reserves, and particularly our proved developed oil and natural gas reserves.

Our remaining 2014 drilling activity will continue to be focused on increasing our oil production and reserves in South Texas, primarily in the Eagle Ford shale play, while expanding our delineation and development efforts and building reserves in the Permian Basin in Southeast New Mexico and West Texas. As of November 5, 2014, we were operating four contracted drilling rigs — two in the Eagle Ford shale and two in the Permian Basin. Because of the timing of the addition of the second drilling rig in the Permian Basin and our projected drilling and completions schedule, we do not expect this rig to materially impact our anticipated 2014 oil and natural gas production or our anticipated 2014 oil and natural gas revenues. Rather, we anticipate that the addition of this second rig in the Permian Basin will have a material impact on our operations and financial results beginning in 2015. In addition, we have decided to further accelerate our Permian Basin drilling program by adding at least one additional rig at the beginning of 2015.

A subsidiary of Chesapeake Energy Corporation ("Chesapeake") is in the process of drilling up to 45 gross (8.7 net) Haynesville shale wells on our Elm Grove acreage in southern Caddo Parish, Louisiana through early 2016. We retain the right to participate for up to a 25% working interest in all wells drilled on this property with our working interest proportionately reduced to our leasehold position in any individual drilling unit. Chesapeake began actively drilling on these properties during the second quarter of 2014, and had three rigs operating on these properties during the third quarter of 2014. The anticipated capital expenditures associated with this drilling program constitute approximately 10% our anticipated capital expenditures in 2014. These wells are being drilled and completed in a multi-well batch mode, and as of November 5, 2014, Chesapeake had completed and placed nine gross (2.0 net to the Company) wells on production, five late in the third quarter and four at the start of the fourth quarter. As of November 5, 2014, these nine gross (2.0 net) wells each were producing between 8 and 12 MMcf (gross) of natural gas per day, or a total of approximately 17 MMcf of natural gas per day net to our interest.

As a result of (i) our determination to operate two drilling rigs in the Permian Basin for the remainder of 2014, (ii) the ongoing and anticipated Chesapeake drilling activity in the Haynesville shale and (iii) additional leasehold and seismic data acquisitions anticipated throughout the remainder of 2014, we increased our 2014 capital expenditure budget from $440.0 million to $570.0 million during the second quarter of 2014. At September 30, 2014, we had incurred $459.5 million, or approximately 81%, of this anticipated 2014 capital expenditure budget.

We had two contracted drilling rigs operating in the Permian Basin during the third quarter of 2014 — one in Loving County, Texas and the other in Lea County, New Mexico. During the third quarter of 2014, we completed and began producing oil and natural gas from five gross (4.6 net) operated Permian Basin wells. We completed three operated wells in our Wolf prospect area in Loving County, Texas — the Norton Schaub #1H, the Johnson 44-02S-B53 #204H and the Arno #1H wells — and two operated wells in our Ranger prospect area in Lea County, New Mexico — the Pickard State 20-18-34 #1H and the Pickard State 20-18-34 #2H wells. The Norton Schaub #1H, the Pickard State 20-18-34 #1H and the Pickard State 20-18-34 #2H wells began producing in July, and the Johnson 44-02S-B53 #204H and the Arno #1H wells were completed and began

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testing in September. As a result, these five wells did not contribute fully to production volumes for the third quarter of 2014 or the nine months ended September 30, 2014.

In the Wolf prospect area in Loving County, Texas, the Johnson 44-02S-B53 #204H well flowed 1,286 BOE per day, including 793 Bbl of oil per day and 3.0 MMcf of natural gas per day (62% oil), at approximately 4,000 pounds per square inch ("psi") flowing surface pressure on a 24/64th inch choke during its 24-hour initial potential test. This well was completed in the upper portion of the geopressured Wolfcamp formation, the Wolfcamp "A", at approximately 11,200 feet true vertical depth. We drilled a 4,600-ft horizontal lateral in the Johnson 44-02S-B53 #204H well and completed it with 19 hydraulic fracturing stages, including approximately 200,000 Bbl of fluid and 9.4 million pounds of sand. The Arno #1H well flowed 1,110 BOE per day, including 300 Bbl of oil per day and 4.9 MMcf of natural gas per day (27% oil), at approximately 4,100 psi surface pressure on a 26/64th inch choke during its 24-hour initial potential test. This well was also completed in the Wolfcamp "A" bench at approximately 10,600 feet true vertical depth. We drilled a 5,400-ft horizontal lateral in the Arno #1H well and completed it with 22 hydraulic fracturing stages, including 226,000 Bbl of fluid and 10.6 million pounds of sand.

The Johnson 44-02S-B53 #204H and the Arno #1H wells are the third and fourth successful tests of the Wolfcamp "A" bench in our Wolf prospect area, along with the Dorothy White #1H and Norton Schaub #1H wells. The Dorothy White #1H well continues to exhibit strong performance since being placed on production in January 2014. In approximately ten months on production, including its initial cleanup phase, the Dorothy White #1H well has produced approximately 246,000 BOE, including 166,000 Bbl of oil (67% oil), and is currently producing about 500 Bbl of oil per day and 1.5 MMcf of natural gas per day at almost 2,000 psi flowing surface pressure. The Norton Schaub #1H well has produced 85,000 BOE, including 59,000 Bbl of oil (69%), in three months of production and is currently producing about 420 Bbl of oil per day and 1.2 MMcf of natural gas per day at over 1,800 psi flowing surface pressure. Based on the success of these four wells, we intend to operate one of our two Permian Basin drilling rigs full time in the Loving County area in development mode throughout the remainder of 2014.

In the Ranger prospect area in Lea County, New Mexico, the Pickard State 20-18-34 #2H well flowed 270 BOE per day, including 232 Bbl of oil per day and 225 Mcf of natural gas per day (86% oil) at 1,150 psi surface pressure on an 18/64th inch choke during its 24-hour initial potential test. This well was completed in the Wolfcamp "D" bench at approximately 12,000 feet true vertical depth, and we believe it to be the northernmost horizontal completion in the Wolfcamp "D" formation in the Delaware Basin. We drilled a 4,300-ft horizontal lateral in the Pickard State 20-18-34 #2H well and completed it with 17 hydraulic fracturing stages, including 192,000 Bbl of fluid and 8.2 million pounds of sand. The Pickard State 20-18-34 #2H well has produced approximately 21,000 BOE in just over three months of production and is still producing approximately 200 BOE per day, including 150 Bbl of oil per day with gas-lift assist. Although these results are more modest than our other Permian Basin wells, we are encouraged by the geopressured nature of this horizon, other zones of interest and the stabilized production volumes of the current completion in the Wolfcamp "D" section. As a result, we expect to drill another Wolfcamp "D" test in early 2015, most likely in our Twin Lakes prospect area.

Elsewhere in the Ranger prospect area, our first two Second Bone Spring completions continue to perform well. The Ranger 33 State Com #1H well has produced 158,000 BOE, including 144,000 Bbl of oil (91% oil), in its first year on production and continues to produce about 300 Bbl of oil per day with gas-lift assist. The Pickard State 20-18-34 #1H well has produced 43,000 BOE, including 40,000 Bbl of oil (92% oil), after just over three months of production. Given the early success of the gas-lift assist on the Ranger 33 State Com #1H well, the Pickard State 20-18-34 #1H well was also equipped with gas-lift assist within about 30 days following its initial completion. At November 5, 2014, this well has produced an average of about 400 Bbl of oil per day with gas-lift assist over the last 30 days.

At November 5, 2014, we are operating two drilling rigs in the Eagle Ford shale, and both are currently drilling in La Salle County. Both rigs are "walking" rigs, and we plan to conduct batch drilling on our Eagle Ford properties using these two rigs for the remainder of 2014. During the third quarter of 2014, we completed and began producing oil and natural gas from ten gross (9.4 net) Eagle Ford wells, all of which were operated wells. We completed three Eagle Ford wells each on our Northcut and Martin Ranch leases in La Salle County, three wells on our Danysh leases in Karnes County and one well on our Lyssy lease in southern Wilson County. Immediately following the end of the third quarter, in early October, we also completed and began producing three gross (3.0 net) additional Eagle Ford wells on our Pawelek lease in Karnes County. The Northcut wells began producing in mid-July, the Danysh wells began producing at the end of July, the Martin Ranch wells began producing in mid-September and the Lyssy well began producing in late September. As a result, these wells did not contribute fully to production volumes for the third quarter of 2014 or the first nine months of 2014. Due to (i) batch drilling operations and other operating practices aimed at saving costs, improving operational efficiencies and increasing estimated ultimate recoveries, (ii) increased completion activity from industry in these areas, (iii) protection of producing wells during the drilling and completion of offsetting wells by both us and other operators and (iv) our continuing practice of managing bottomhole pressure by producing wells on restricted choke sizes, we had as much as 15 to 20% of our production capacity shut in or restricted at various times during the third quarter of 2014. For the nine months ended September 30, 2014, we completed and

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began producing oil and natural gas from 31 gross (26.6 net) Eagle Ford wells, including 27 gross (25.5 net) operated wells and four gross (1.1 net) non-operated wells.

Our downspacing efforts in the Eagle Ford shale continue to achieve positive results. Since the beginning of the third quarter of 2014, we have drilled, completed and placed on production six gross (6.0 net) wells on our Danysh and Pawelek leases at 40 to 50-acre spacing. In the Danysh lease in Karnes County, the three most recent wells averaged 880 BOE per day, including 770 Bbl of oil per day and 650 Mcf of natural gas per day (88% oil), at 2,400 to 2,500 psi flowing surface pressure on a 14/64th inch choke during their 24-hour initial potential tests. On the Pawelek lease in Karnes County, the three most recent wells averaged 790 BOE per day, including 694 Bbl of oil per day and 575 Mcf of natural gas per day (88% oil), at 2,700 to 3,000 psi flowing surface pressure on a 14/64th inch choke during their 24-hour initial potential tests.

The three most recent wells drilled and placed on production on our Martin Ranch lease were drilled at 40-acre spacing with positive initial test results. The 24-hour initial potential tests from these three wells averaged approximately 790 BOE per day, including 730 Bbl of oil per day and 380 Mcf of natural gas per day (92% oil), at flowing surface pressures ranging from 1,900 to 2,750 psi on a 14/64th inch choke. We will continue to test 40 to 50-acre spacing on our other properties in northwest La Salle County throughout the remainder of 2014. Given the results from our leases in both the central and western portions of the Eagle Ford shale thus far, we currently expect to develop our remaining acreage in these areas on 40 to 50-acre spacing.

At September 30, 2014, our estimated total proved oil and natural gas reserves were 61.0 million BOE, including 21.5 million Bbl of oil and 236.7 Bcf of natural gas, with a PV-10 of $952.0 million and a Standardized Measure of $835.1 million. At December 31, 2013, our estimated proved oil and natural gas reserves were 51.7 million BOE, including 16.4 million Bbl of oil and 212.2 Bcf of natural gas, and at September 30, 2013, our estimated 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. Our proved oil reserves of 21.5 million Bbl at September 30, 2014 increased 55%, as compared to 13.9 million Bbl at September 30, 2013, and 32%, as compared to 16.4 million Bbl at December 31, 2013. 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.

We realized a weighted average oil price of $92.39 per Bbl for the three months ended September 30, 2014, as compared to $104.15 per Bbl for the three months ended September 30, 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. Oil production from our properties in the Permian Basin in Southeast New Mexico and West Texas is sold on a West Texas Intermediate at Midland oil price index less transportation costs. We realized a weighted average natural gas price of $4.95 per Mcf for the three months ended September 30, 2014, as compared to $4.71 per Mcf for the three months ended September 30, 2013. This price reflects an uplift as a result of natural gas liquids we produce with our Eagle Ford natural gas production, and we also expect to receive an uplift in the price we receive for most of our natural gas production from the Permian Basin due to natural gas liquids. Our natural gas production from the Haynesville shale is mostly dry natural gas and does not receive a price uplift as a result of natural gas liquids. See "— Results of Operations" below for more information on our oil and natural gas prices received during the third quarter of 2014. Since the end of the second quarter of 2014, oil prices have declined significantly and at November 5, 2014, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date closed at $78.68 per Bbl. We are mindful of this recent decline in oil prices and are considering any adjustments that may be required to our operating plans and capital expenditures for 2015 as a result.

We began 2014 with approximately 70,800 gross (44,800 net) acres in the Permian Basin in Southeast New Mexico and West Texas. Between January 1 and October 1, 2014, we acquired an additional 27,700 gross (20,200 net) acres in this area, primarily in Loving County, Texas and in Lea and Eddy Counties, New Mexico. Including these acreage acquisitions, at October 1, 2014, our total Permian Basin acreage position was approximately 98,400 gross (65,000 net) acres. We have also been actively acquiring additional Eagle Ford acreage in South Texas. Between January 1, 2014 and October 1, 2014, we acquired 3,100 gross (2,900 net) acres in South Texas prospective for the Eagle Ford shale in La Salle, Karnes and southern Atascosa Counties. We plan to continue our leasing and acquisition efforts in the Permian Basin, Eagle Ford shale and Haynesville shale as opportunities are identified.

Estimated Proved Reserves

The following table sets forth our estimated total proved oil and natural gas reserves at September 30, 2014, December 31, 2013 and September 30, 2013. Our production and proved reserves are reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where we produce liquids-rich natural gas, such as in the Eagle Ford shale in South Texas, the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers. These reserves estimates were prepared

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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, 2014	December 31, 2013	September 30, 2013
Estimated Proved Reserves Data: (1) (2)			
Estimated proved reserves:			
Oil (MBbl)(3)	21,519	16,362	13,878
Natural Gas (Bcf)(4)	236.7	212.2	182.0
Total (MBOE)(5)	60,969	51,729	44,211
Estimated proved developed reserves:			
Oil (MBbl)(3)	12,192	8,258	6,859
Natural Gas (Bcf)(4)	78.3	53.5	56.9
Total (MBOE)(5)	25,242	17,168	16,338
Percent developed	41.4 %	33.2 %	37.0 %
Estimated proved undeveloped reserves:			
Oil (MBbl)(3)	9,327	8,104	7,019
Natural Gas (Bcf)(4)	158.4	158.7	125.1
Total (MBOE)(5)	35,727	34,561	27,873
PV-10(6) (in millions)	$952.0	$655.2	$538.6
Standardized Measure(7) (in millions)	$835.1	$578.7	$486.1

(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 2013 through September 2014 were $95.56 per Bbl for oil and $4.236 per MMBtu for natural gas, for the period from January 2013 through December 2013 were $93.42 per Bbl for oil and $3.670 per MMBtu for natural gas and for the period from October 2012 through September 2013 were $91.69 per Bbl for oil and $3.605 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) One billion cubic feet of natural gas.

(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, 2014, December 31, 2013 and September 30, 2013 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, 2014, December 31, 2013 and September 30, 2013 were, in millions, $116.9, $76.5 and $52.5, 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, 2014, our estimated total proved oil and natural gas reserves were 61.0 million BOE, including 21.5 million Bbl of oil and 236.7 Bcf of natural gas, with a PV-10 of $952.0 million and a Standardized Measure of $835.1 million. At December 31, 2013, our estimated total proved oil and natural gas reserves were 51.7 million BOE, including 16.4 million Bbl of oil and 212.2 Bcf of natural gas, and at September 30, 2013, our estimated total proved oil and natural gas reserves were

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44.2 million BOE, including 13.9 million Bbl of oil and 182.0 Bcf of natural gas. Our proved oil reserves of 21.5 million Bbl at September 30, 2014 increased 32%, as compared to 16.4 million Bbl at December 31, 2013, and 55%, as compared to 13.9 million Bbl at September 30, 2013. During the nine months ended September 30, 2014, our proved developed reserves increased 47% from 17.2 million BOE at December 31, 2013 to 25.2 million BOE at September 30, 2014. Year-over-year, our proved developed reserves increased 54% from 16.3 million BOE at September 30, 2013. At September 30, 2014, approximately 41% of our total proved reserves were proved developed reserves, 35% of our total proved reserves were oil and 65% of our total proved reserves were natural gas.

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

Revenue from Contracts with Customers. In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update, or ASU, 2014-09, Revenue from Contracts with Customers (Topic 606), which specifies how and when to recognize revenue. This standard also requires expanded disclosures surrounding revenue recognition and is intended to improve and converge with international standards the financial reporting requirements for revenue from contracts with customers. ASU 2014-09 will become effective for fiscal years beginning after December 15, 2016, i.e., in our first fiscal quarter of 2017. We are currently evaluating the impact, if any, of the adoption of this ASU on our consolidated financial statements.

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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,	
	2014	2013	2014	2013
	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)
Operating Data:				
Revenues (in thousands):[1]				
Oil	$77,546	$ 64,226	$219,714	$ 157,528
Natural gas	19,071	17,642	54,891	41,839
Total oil and natural gas revenues	96,617	81,868	274,605	199,367
Realized loss on derivatives	(701)	(1,165)	(5,458)	(519)
Unrealized gain (loss) on derivatives	16,293	(9,327)	7,950	(6,626)
Total revenues	$112,209	$ 71,376	$277,097	$ 192,222
Net Production Volumes:[1]				
Oil (MBbl)[2]	839	617	2,302	1,524
Natural gas (Bcf)[3]	3.8	3.7	9.9	10.0
Total oil equivalent (MBOE)[4]	1,481	1,240	3,956	3,184
Average daily production (BOE/d)[5]	16,096	13,482	14,490	11,663
Average Sales Prices:				
Oil, with realized derivatives (per Bbl)	$91.42	$ 101.69	$93.48	$ 102.24
Oil, without realized derivatives (per Bbl)	$92.39	$ 104.15	$95.45	$ 103.34
Natural gas, with realized derivatives (per Mcf)	$4.99	$ 4.81	$5.44	$ 4.35
Natural gas, without realized derivatives (per Mcf)	$4.95	$ 4.71	$5.53	$ 4.20

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(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 billion cubic feet of natural gas.

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

(5) 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, 2014 as Compared to Three Months Ended September 30, 2013

Oil and natural gas revenues. Our oil and natural gas revenues increased by $14.7 million to $96.6 million, or an increase of 18%, for the three months ended September 30, 2014, as compared to $81.9 million for the three months ended September 30, 2013. This increase in oil and natural gas revenues includes an increase in our oil revenues of $13.3 million and an increase in our natural gas revenues of $1.4 million for the three months ended September 30, 2014, as compared to the three months ended September 30, 2013. Our oil revenues increased 21% to $77.5 million for the three months ended September 30, 2014, as compared to $64.2 million for the three months ended September 30, 2013. This increase in oil revenues reflects the increase in our oil production by 36% to 839,000 Bbl of oil in the third quarter of 2014, or 9,123 Bbl of oil per day, as compared to 617,000 Bbl of oil in the third quarter of 2013, or 6,703 Bbl of oil per day. This increase in oil production is attributable to faster drilling operations and better completions in the Eagle Ford shale, as well as better-than-expected initial production contributions from newly drilled wells in the Permian Basin. Our natural gas revenues increased 8% to $19.1 million for the three months ended September 30, 2014, as compared to $17.6 million for the three months ended September 30, 2013. The increase in natural gas revenues resulted from a higher weighted average natural gas price of $4.95 per Mcf realized during the third quarter of 2014, as compared to a weighted average natural gas price of $4.71 per Mcf realized during the third quarter of 2013, as well as a 3% increase in our natural gas production to 3.8 Bcf of natural gas in the third quarter of

2014, as compared to 3.7 Bcf of natural gas in the third quarter of 2013. This increase in the weighted average natural gas price was attributable to increased natural gas prices between the two periods, as well as the higher heating quality of, and the natural gas liquids extracted from, the natural gas produced primarily from our Eagle Ford shale wells, as compared to our Haynesville shale and

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Cotton Valley wells. The increase in natural gas production was primarily attributable to our drilling operations in both South Texas and the Permian Basin, as well as initial production contributions from newly drilled non-operated wells in the Haynesville shale in Northwest Louisiana during the three months ended September 30, 2014.

Realized loss on derivatives. Our realized loss on derivatives was $0.7 million for the three months ended September 30, 2014, as compared to a realized loss of $1.2 million for the three months ended September 30, 2013. For the three months ended September 30, 2014, we realized a net loss of $0.8 million and net gains of $19,000 and $96,000 attributable to our oil, natural gas and natural gas liquids (“NGL”) derivative contracts, respectively. For the three months ended September 30, 2013, we realized a net loss of $1.5 million on our oil derivative contracts and net gains of $0.1 million and $0.2 million on our natural gas and NGL derivative contracts, respectively. The decrease in the realized gain on our natural gas derivative contracts between the respective periods resulted primarily from higher natural gas prices for the three months ended September 30, 2014, as compared to the three months ended September 30, 2013. The decrease in the realized gain on our NGL derivative contracts between the respective periods resulted from the decrease in the fixed prices on certain of our NGL derivative contracts for the three months ended September 30, 2014, as compared to the three months ended September 30, 2013. We realized a loss of approximately $1.23 per Bbl and a gain of $0.01 per MMBtu hedged on all of our oil and natural gas derivative contracts, respectively, during the three months ended September 30, 2014, as compared to a loss of $3.33 per Bbl and a gain of $0.06 per MMBtu hedged on all of our oil and natural gas derivative contracts, respectively, during the three months ended September 30, 2013. During the third quarter of 2014, our natural gas costless collar contracts had average floor and ceiling prices of $3.50 per MMBtu and $4.93 per MMBtu, respectively, as compared to $3.32 per MMBtu and $4.59 per MMBtu, respectively, during the third quarter of 2013. The realized loss on our oil derivative contracts during the three months ended September 30, 2014 and 2013 resulted from oil prices that were higher than the ceiling prices of several of our oil costless collar contracts. The average floor prices of our oil costless collar contracts were $87.82 per Bbl and $87.27 per Bbl as of September 30, 2014 and September 30, 2013, respectively. The average ceiling prices of our oil costless collar contracts were $98.95 per Bbl and $108.23 per Bbl as of September 30, 2014 and September 30, 2013, respectively. Our total oil and natural gas volumes hedged for the three months ended September 30, 2014 were 45% and 29% higher, respectively, than the total oil and natural gas volumes hedged for the same period in 2013.

Unrealized gain (loss) on derivatives. Our unrealized gain on derivatives was $16.3 million for the three months ended September 30, 2014, as compared to an unrealized loss of $9.3 million for the three months ended September 30, 2013. During the period from June 30, 2014 to September 30, 2014, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts increased from a net liability of $11.1 million to a net asset of $5.2 million, resulting in an unrealized gain on derivatives of $16.3 million for the three months ended September 30, 2014. The net fair value of our open oil derivative contracts increased $14.1 million at September 30, 2014, as compared to June 30, 2014, due to lower oil futures prices at September 30, 2014. The net fair value of our open natural gas derivative contracts increased $1.9 million at September 30, 2014, as compared to June 30, 2014, as natural gas futures prices decreased during this period. The net fair value of our open NGL derivative contracts increased $0.3 million at September 30, 2014, as compared to June 30, 2014, due to slight decreases in the futures prices for certain of these commodities. During the period from June 30, 2013 to September 30, 2013, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts decreased from $7.2 million to $(2.1) million due to increases in futures prices for these commodities, resulting in an unrealized loss on derivatives of $9.3 million for the three months ended September 30, 2013.

Nine Months Ended September 30, 2014 as Compared to Nine Months Ended September 30, 2013

Oil and natural gas revenues. Our oil and natural gas revenues increased by approximately $75.2 million to approximately $274.6 million, or an increase of about 38%, for the nine months ended September 30, 2014, as compared to the nine months ended September 30, 2013. This increase in oil and natural gas revenues includes an increase in our oil revenues of $62.2 million and an increase in our natural gas revenues of $13.1 million for the nine months ended September 30, 2014, as compared to the nine months ended September 30, 2013. Our oil revenues increased by 39% to $219.7 million for the nine months ended September 30, 2014, as compared to $157.5 million for the nine months ended September 30, 2013. This increase reflects the increase in our oil production by 51% to 2,302 MBbl of oil in the nine months ended September 30, 2014, or about 8,432 Bbl of oil per day, as compared to 1,524

MBbl of oil, or about 5,584 Bbl of oil per day, in the nine months ended September 30, 2013. This increased oil production is primarily attributable to faster drilling operations and better completions in the Eagle Ford shale, as well as better-than-expected initial production contributions from newly drilled wells in the Permian Basin. The increased revenues attributable to increased production were partially offset by a lower oil price of $95.45 per Bbl realized for the nine months ended September 30, 2014, as compared to $103.34 per Bbl realized for the nine months ended September 30, 2013. The increase in natural gas revenues resulted from a higher weighted average natural gas price of $5.53 per Mcf realized during the nine months ended September 30, 2014, as compared to a weighted average natural gas price of $4.20 per Mcf realized during the nine months ended September 30, 2013. This increase in the weighted average natural gas price was attributable to increased natural gas prices between the two periods, as well as the higher heating quality of, and the

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natural gas liquids extracted from, the natural gas produced primarily from our Eagle Ford shale wells, as compared to our Haynesville shale and Cotton Valley wells.

Realized loss on derivatives. We realized a loss on derivatives of approximately $5.5 million for the nine months ended September 30, 2014, as compared to a loss of approximately $0.5 million for the nine months ended September 30, 2013. For the nine months ended September 30, 2014, we realized net losses of approximately $4.5 million, $0.8 million and $0.2 million attributable to our oil, natural gas and NGL derivative contracts, respectively. For the nine months ended September 30, 2013, we realized a net loss of approximately $2.0 million attributable to our oil derivative contracts and net gains of approximately $0.8 million and $0.7 million attributable to our natural gas and NGL derivative contracts, respectively. The net loss realized from our derivative contracts for the nine months ended September 30, 2014 resulted primarily from oil and natural gas prices in excess of the ceiling prices on certain of our oil and natural gas derivative contracts during the nine months ended September 30, 2014, as compared to the nine months ended September 30, 2013, as well as lower fixed prices on certain of our NGL derivative contracts during the nine months ended September 30, 2014, as compared to the nine months ended September 30, 2013. We realized a loss of approximately $2.34 per Bbl and $0.08 per MMBtu hedged on all of our oil and natural gas derivative contracts, respectively, during the nine months ended September 30, 2014, as compared to a loss of $1.60 per Bbl and a gain of $0.13 per MMBtu hedged on all of our oil and natural gas derivative contracts, respectively, during the nine months ended September 30, 2013. During the nine months ended September 30, 2014, our natural gas costless collar contracts had average floor and ceiling prices of $3.48 per MMBtu and $4.94 per MMBtu, respectively, as compared to $3.40 per MMBtu and $4.73 per MMBtu, respectively, for the nine months ended September 30, 2013. The average floor prices of our oil costless collar contracts were $87.76 per Bbl and $87.27 per Bbl as of September 30, 2014 and September 30, 2013, respectively. The average ceiling prices of our oil costless collar contracts were $99.48 per Bbl and $109.49 per Bbl as of September 30, 2014 and September 30, 2013, respectively. Our total oil and natural gas volumes hedged for the nine months ended September 30, 2014 were 56% and 51% higher, respectively, than the total oil and natural gas volumes hedged for the same period in 2013.

Unrealized gain (loss) on derivatives. Our unrealized gain on derivatives was approximately $8.0 million for the nine months ended September 30, 2014, as compared to an unrealized loss of approximately $6.6 million for the nine months ended September 30, 2013. During the period from December 31, 2013 through September 30, 2014, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts increased from a net liability of approximately $2.8 million to a net asset of approximately $5.2 million, resulting in an unrealized gain on derivatives of approximately $8.0 million for the nine months ended September 30, 2014. This gain is primarily attributable to an increase in the net fair value of our open oil contracts for the nine months ended September 30, 2014. This increase was due primarily to a decrease in oil futures prices, which increased the net fair value of our open oil contracts by approximately $6.4 million between December 31, 2013 and September 30, 2014. The net fair value of our open natural gas contracts increased by $1.4 million during the same period. During the period from December 31, 2012 through September 30, 2013, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts decreased from $4.5 million to $(2.1) million, resulting in an unrealized loss on derivatives of $6.6 million for the nine months ended September 30, 2013.

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Expenses

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
(In thousands, except expenses per BOE)	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)
Expenses:				
Production taxes and marketing	$8,617	$ 6,559	$23,739	$ 15,107
Lease operating	13,691	8,569	34,747	29,608
Depletion, depreciation and amortization	35,143	26,127	90,970	74,593
Accretion of asset retirement obligations	130	86	371	248
Full-cost ceiling impairment	—	—	—	21,229
General and administrative	8,099	5,395	23,417	14,146
Total expenses	65,680	46,736	173,244	154,931
Operating income	46,529	24,640	103,853	37,291
Other income (expense):				
Net loss on asset sales and inventory impairment	—	—	—	(192)
Interest expense	(673)	(2,038)	(3,685)	(4,919)
Interest and other income	267	66	715	181
Total other expense	(406)	(1,972)	(2,970)	(4,930)
Income before income taxes	46,123	22,668	100,883	32,361
Total income tax provision	16,504	2,563	36,675	2,641
Net income	$29,619	$ 20,105	$64,208	$ 29,720
Expenses per BOE:				
Production taxes and marketing	$5.82	$ 5.29	$6.00	$ 4.74
Lease operating	$9.25	$ 6.91	$8.78	$ 9.30
Depletion, depreciation and amortization	$23.73	$ 21.06	$23.00	$ 23.43
General and administrative	$5.47	$ 4.35	$5.92	$ 4.44

Three Months Ended September 30, 2014 as Compared to Three Months Ended September 30, 2013

Production taxes and marketing. Our production taxes and marketing expenses increased by $2.1 million to $8.6 million, or an increase of 31%, for the three months ended September 30, 2014, as compared to $6.6 million for the three months ended September 30, 2013, in part due to our increased oil and natural gas production between the respective periods. On a unit-of-production basis, however, our production taxes and marketing expenses increased by only 10% to $5.82 per BOE for the three months ended September 30, 2014, as compared to $5.29 per BOE for the three months ended September 30, 2013. The increase in our production taxes and marketing expenses was primarily due to the increase in our oil and natural gas revenues by 18% during the three months ended September 30, 2014, as compared to the three months ended September 30, 2013. A large portion 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, 2014, as compared to the three months ended September 30, 2013, resulting primarily from our drilling operations in the Eagle Ford shale, as well as initial production contributions from our newly drilled wells in the Permian Basin. Oil comprised 57% of our total production volume in the third quarter of 2014, as compared to 50% in the third quarter of 2013.

Lease operating expenses. Our lease operating expenses increased by $5.1 million to $13.7 million, or an increase of 60%, for the three months ended September 30, 2014, as compared to $8.6 million for the three months ended September 30, 2013. Between these respective periods, our total oil and natural gas production increased 19% to 1,481 MBOE from approximately 1,240 MBOE, including an increase in oil production of 36% to 839 MBbl from 617 MBbl. Our lease operating expenses per unit of production increased 34% to $9.25 per BOE for the three months ended September 30, 2014, as compared to $6.91 per BOE for the three months ended September 30, 2013, primarily due to the higher percentage of oil we produced in the third quarter of 2014. Oil production was 57% of total production by volume in the third quarter of 2014, as compared to 50% of total production by volume in the third quarter of 2013. This increase in lease operating expenses was also attributable to increased costs associated with initial oil production operations in the Permian Basin. These increased costs were the result

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of (i) additional personnel required to oversee operations; (ii) increased salt water disposal costs due to the higher initial volumes of water being produced by these wells, as compared to wells in the Eagle Ford shale; (iii) higher per barrel rates being charged for disposal as compared to the Eagle Ford shale; and (iv) the overall increase in oil production between the comparable periods.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $9.0 million to $35.1 million, or an increase of 35%, for the three months ended September 30, 2014, as compared to the three months ended September 30, 2013. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased to $23.73 per BOE for the three months ended September 30, 2014, or an increase of only 13%, from $21.06 per BOE for the three months ended September 30, 2013. The increase in the total depletion, depreciation and amortization expenses is attributable to the increase in our oil and natural gas production of 19% to 1,481 MBOE from 1,240 MBOE between the respective periods. The increase in the unit-of-production depletion, depreciation and amortization expenses is attributable to the increase in our oil production as a percentage of our total production to 57% from 50% between the respective periods and to the higher finding and development costs associated with our oil reserves as compared to our natural gas reserves on a per BOE basis.

General and administrative. Our general and administrative expenses increased by $2.7 million to $8.1 million, or an increase of 50%, for the three months ended September 30, 2014, as compared to $5.4 million for the three months ended September 30, 2013. The increase in our general and administrative expenses for the three months ended September 30, 2014 was largely attributable to increased payroll expenses associated with additional personnel joining the Company between the respective periods to support our increased land, geoscience, drilling, completion and production operations. General and administrative expenses also included non-cash stock-based compensation expense of $1.0 million for the three months ended September 30, 2014, as compared to $1.2 million for the three months ended September 30, 2013. While our general and administrative expenses increased 50% on an absolute basis, our general and administrative expenses on a unit-of-production basis increased only 26% to $5.47 per BOE for the three months ended September 30, 2014, as compared to $4.35 per BOE for the three months ended September 30, 2013, as a result of our increased oil equivalent production between the respective periods.

Interest expense. For the three months ended September 30, 2014, we incurred total interest expense of $1.5 million. We capitalized $0.8 million of our interest expense on certain qualifying projects for the three months ended September 30, 2014 and expensed the remaining $0.7 million to operations. For the three months ended September 30, 2013, we incurred total interest expense of $2.4 million. We capitalized $0.4 million of our interest expense on certain qualifying projects for the three months ended September 30, 2013 and expensed the remaining $2.0 million to operations. The decrease in total interest expense is attributable to a decrease in both the average outstanding borrowings and the average effective interest rate under our third amended and restated credit agreement (the “Credit Agreement”) between the comparable periods. At September 30, 2014, we had $250.0 million in borrowings and $0.6 million in letters of credit outstanding under our Credit Agreement. As we increase the borrowings under our Credit Agreement, we expect to incur increased interest expense.

Interest and other income. Our interest and other income increased by $201,000 to $267,000 for the three months ended September 30, 2014, as compared to $66,000 for the three months ended September 30, 2013. The increase in our interest and other income was due primarily to an increase in the natural gas transportation income we received from third parties during the three months ended September 30, 2014, as compared to the three months ended September 30, 2013, although on the whole, this item is an insignificant component of our overall income.

Total income tax provision. Based on our projections for the remainder of 2014, we anticipate incurring a slightly lower alternative minimum tax (“AMT”) liability for the year ending December 31, 2014 than previously estimated, which resulted in the current income tax benefit of $0.2 million for the three months ended September 30, 2014. The total income tax provision of $16.5 million for the three months ended September 30, 2014 also includes $16.7 million of deferred income taxes. Our effective tax rate for the three months ended September 30, 2014 was 35.8%. Total income tax expense for the three months ended September 30, 2014 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due to the impact of permanent differences between book and taxable income. At September 30, 2013, based on our projections for the remainder of 2013, we anticipated incurring a small AMT liability for the year ending December 31, 2013, the proportionate share of which was recorded as the current income tax provision of $0.9 million for the three months ended September 30, 2013. 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.

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Nine Months Ended September 30, 2014 as Compared to Nine Months Ended September 30, 2013

Production taxes and marketing. Our production taxes and marketing expenses increased by approximately $8.6 million to approximately $23.7 million, or an increase of approximately 57%, for the nine months ended September 30, 2014, as compared to $15.1 million for the nine months ended September 30, 2013, in part due to our increased oil and natural gas production between the respective periods. On a unit-of-production basis, however, our production taxes and marketing expenses increased by only 27% to $6.00 per BOE for the nine months ended September 30, 2014, as compared to $4.74 per BOE for the nine months ended September 30, 2013. The increase in our production taxes and marketing expenses was primarily due to the increase in our oil and natural gas revenues by 38% during the nine months ended September 30, 2014, as compared to the nine months ended September 30, 2013. A large portion of this increase was attributable to production taxes associated with the increase in oil production and associated oil revenues during the nine months ended September 30, 2014, as compared to the nine months ended September 30, 2013, resulting primarily from our drilling operations in the Eagle Ford shale, as well as initial production contributions from our newly drilled wells in the Permian Basin. Oil comprised approximately 58% of our total production volume in the first nine months of 2014, as compared to 48% in the first nine months of 2013. The increase in production taxes and marketing expenses during the first nine months of 2014 also reflected the higher percentage of our natural gas production from the Eagle Ford shale in Texas, where natural gas production taxes are higher than production taxes associated with Haynesville shale natural gas in Louisiana.

Lease operating expenses. Our lease operating expenses increased by approximately $5.1 million to $34.7 million for the nine months ended September 30, 2014, as compared to $29.6 million for the nine months ended September 30, 2013. Our lease operating expenses per unit of production decreased 6% to $8.78 per BOE for the nine months ended September 30, 2014, as compared to $9.30 per BOE for the nine months ended September 30, 2013. Between these respective periods, our total oil and natural gas production increased about 24% to 3,956 MBOE from 3,184 MBOE, including an increase of 51% in oil production to 2,302 MBbl of oil from 1,524 MBbl of oil, which would typically result in higher lease operating expenses. Oil production was 58% of total production by volume for the nine months ended September 30, 2014, as compared to only 48% of total production by volume for the nine months ended September 30, 2013. The decrease achieved in lease operating expenses on a per unit basis resulted from the progress we have made in reducing our lease operating expenses in the Eagle Ford shale during the last twelve months, which was primarily attributable to (1) the installation of permanent production facilities on almost all of our Eagle Ford properties, alleviating the need for the extended use of flowback equipment to produce newly completed Eagle Ford wells, (2) the early use of gas lift on most of our newly completed Eagle Ford wells and (3) a decrease in salt water disposal costs on a per barrel basis, as well as continued improvement in overall operational processes, in our South Texas operations.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $16.4 million to $91.0 million, or an increase of 22%, for the nine months ended September 30, 2014, as compared to $74.6 million for the nine months ended September 30, 2013. On a unit-of-production basis, our depletion, depreciation and amortization expenses decreased to $23.00 per BOE for the nine months ended September 30, 2014, or a decrease of about 2%, from $23.43 per BOE for the nine months ended September 30, 2013. The increase in the total depletion, depreciation and amortization expenses was attributable to the increase in our oil and natural gas production by 24% to 3,956 MBOE from 3,184 MBOE between the respective periods. The decrease in the per-unit-of-production depletion, depreciation and amortization expenses resulted primarily from significantly higher estimated total proved reserves at September 30, 2014, as compared to estimated total proved reserves at September 30, 2013. 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, 2014 on our depletion, depreciation and amortization expenses, as compared to the nine months ended September 30, 2013, was partially offset by the increase in our proved oil and natural gas reserves to 61.0 million BOE at September 30, 2014 from 44.2 million BOE at September 30, 2013.

Full-cost ceiling impairment. No impairment to the net carrying value of our oil and natural gas properties and no corresponding charge resulting from a full-cost ceiling impairment was recorded during the nine months ended September 30, 2014. 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.

General and administrative. Our general and administrative expenses increased by $9.3 million to $23.4 million, or an increase of approximately 66%, for the nine months ended September 30, 2014, as compared to $14.1 million for the nine months ended September 30, 2013. The increase in our general and administrative expenses was primarily attributable to increased payroll expenses associated with additional personnel joining the Company between the respective periods to support our increased land, geoscience, drilling, completion and production operations. The remaining increase is largely due to an increase in stock-based compensation costs of $1.9 million to $4.7 million for the nine months ended September 30, 2014, as compared to $2.8 million for the nine months ended September 30, 2013. The increase in our stock-based compensation expense was primarily attributable to the continued vesting of awards granted in 2012 and 2013, and new awards granted in 2014, as well as the increased fair value of our liability-based stock options during the nine months ended September 30, 2014, resulting from an increase in the price per share of our common stock from $18.64 to $25.85 during the first nine months of 2014. While our general and administrative expenses increased 66% on an absolute basis, our general and administrative expenses increased by only 33% on a unit-of-production basis to $5.92 per BOE for the nine months ended September 30, 2014, as compared to $4.44 per BOE for the nine months ended September 30, 2013, as a result of our increased production between the respective periods.

Interest expense. For the nine months ended September 30, 2014, we incurred total interest expense of approximately $5.9 million. We capitalized approximately $2.2 million of our interest expense on certain qualifying projects for the nine months ended September 30, 2014 and expensed the remaining $3.7 million to operations. 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. The small decrease in total interest expense is primarily attributable to a decrease in the effective interest rate under our Credit Agreement between the comparable periods. In late May 2014, we used a portion of the net proceeds of our public equity offering to repay $180.0 million of outstanding borrowings under our Credit Agreement. At September 30, 2014, we had $250.0 million in borrowings and $0.6 million in letters of credit outstanding under our Credit Agreement. As we increase the borrowings under our Credit Agreement, we expect to incur increased interest expense.

Interest and other income. Our interest and other income increased by approximately $0.5 million to approximately $0.7 million for the nine months ended September 30, 2014, as compared to approximately $0.2 million for the nine months ended September 30, 2013. The increase in our interest and other income was due primarily to an increase in the natural gas transportation income we received from third parties during the nine months ended September 30, 2014, as compared to the nine months ended September 30, 2013, although on the whole, this item is an insignificant component of our overall income.

Total income tax provision. Based on our projections for the remainder of 2014, we anticipate incurring an AMT liability for the year ending December 31, 2014, the proportionate share of which is recorded as the current income tax provision of approximately $2.7 million for the nine months ended September 30, 2014. The total income tax provision of approximately $36.7 million for the nine months ended September 30, 2014 also includes approximately $34.0 million of deferred income taxes. Our effective tax rate for the nine months ended September 30, 2014 was 36.4%. Total income tax expense for the nine months ended September 30, 2014 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due to the impact of permanent differences between book and taxable income. 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.

Liquidity and Capital Resources

Our primary use of capital has been, and we expect will continue to be for the foreseeable future, for the acquisition, exploration and development of oil and natural gas properties. We continually evaluate potential capital sources, including additional borrowings, equity and debt financings and joint ventures, in order to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital and to continue to grow our operating cash flows.

At September 30, 2014, we had cash totaling $7.7 million, the borrowing base under our Credit Agreement was $450.0 million and we had $250.0 million of outstanding long-term borrowings and $0.6 million in outstanding letters of credit. During the three months ended September 30, 2014, the borrowings under our Credit Agreement bore interest at an effective interest rate of 2.9% per annum. From October 1, 2014 through November 5, 2014, we borrowed an additional $40.0 million under our Credit Agreement to finance a portion of our working capital requirements and capital expenditures.

Our 2014 drilling activity continues to be focused on increasing our oil production and reserves in South Texas in the Eagle Ford shale play, while expanding our delineation and development efforts in the Permian Basin in Southeast New Mexico and West Texas. As of November 5, 2014, we were operating four contracted drilling rigs — two in the Eagle Ford shale and two in the Permian Basin. Because of the timing of the addition of the second drilling rig in the Permian Basin and our projected drilling and completions schedule, we do not expect this rig to materially impact our anticipated 2014 oil and natural gas production or our anticipated 2014 oil and natural gas revenues. Rather, we anticipate that the addition of this second rig in the Permian Basin will start to have a material impact on our operations and financial results beginning in 2015. Based on the success of the first four wells on our Wolf prospect, we intend to operate one of our two Permian Basin drilling rigs full-time in the Loving County area throughout the remainder of 2014. In addition, we have decided to further accelerate our Permian drilling program by adding at least one additional rig at the beginning of 2015.

Chesapeake is in the process of drilling up to 45 gross (8.7 net) Haynesville shale wells on our Elm Grove acreage in southern Caddo Parish, Louisiana through early 2016. We retain the right to participate for up to a 25% working interest in all wells drilled on this property with our working interest proportionately reduced to our leasehold position in any individual drilling unit. Chesapeake began actively drilling on these properties during the second quarter of 2014, and had three rigs operating on these properties during the third quarter of 2014. At November 5, 2014, we had agreed to participate in 21 gross (4.4 net) wells in progress or proposed by Chesapeake on this acreage with an estimated total capital commitment of $37.4 million, portions of which have already been incurred in 2014.

Between January 1, 2014 and October 1, 2014, we acquired 27,700 gross (20,200 net) acres in the Permian Basin and acquired 3,100 gross (2,900 net) acres in the Eagle Ford shale in South Texas. We plan to continue our leasing and acquisition efforts in the Permian Basin, Eagle Ford shale and Haynesville shale as opportunities are identified.

As a result of our determination to operate two drilling rigs in the Permian Basin for the remainder of 2014, the ongoing and anticipated Chesapeake drilling activity in the Haynesville shale and additional leasehold and seismic data acquisitions anticipated throughout the remainder of 2014, we increased our 2014 capital expenditure budget from $440.0 million to $570.0 million during the second quarter of 2014. At September 30, 2014, we had incurred $459.5 million, or approximately 81%, of this anticipated 2014 capital expenditure budget. We anticipate investing $570.0 million for exploration, development and acquisition efforts as follows:

	Amount (in millions)
Exploration, development drilling and completion costs	$ 470.0
Pipeline and infrastructure expenditures	20.0
Leasehold acquisition and 2-D and 3-D seismic data	80.0
Total	$ 570.0

While we have budgeted $570.0 million in capital expenditures for 2014, the amount, timing and allocation of our capital expenditures is largely discretionary and within our control. 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 2014. When oil or natural gas prices decline, as oil prices have done since the end of the second quarter of 2014, or costs increase significantly, we have the flexibility to defer a significant portion of our 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 development activities, contractual obligations, drilling plans for properties we do not operate and other factors both within and outside our control.

As a result of our current availability and anticipated increases in the borrowing base under our Credit Agreement and anticipated increases in our 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 2014 and into 2015. 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.

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 portion of our anticipated cash flows from operations for the remainder of 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 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, 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 2014 and the hedges we currently have in place. Oil prices, in particular, have declined significantly since the end of the second quarter of 2014, and if they remain at current levels or decrease further, this would result in less cash flows from operations than we had previously anticipated.

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If our exploration and development activities are less successful than we anticipate or result in less cash flows than anticipated, or should oil and natural gas prices decline substantially (which oil prices have done in recent months) or our capital expenditure needs increase, we may require additional sources of capital, including through additional borrowings under our Credit Agreement (assuming availability under our borrowing base) or additional credit arrangements, the sale of assets or acreage or entering into one or more joint ventures, none of which may be available. In addition to future borrowings under our Credit Agreement, we may also seek to raise additional funds by issuing debt securities or selling shares of our common stock or securities convertible or exercisable into our common stock (including debt securities or other preferential securities) in the public markets or otherwise. Any such sales of equity or convertible securities would dilute the ownership interest of our existing shareholders. There is no guarantee that we would be able to sell such debt or equity securities on terms acceptable to us. It is also possible that, to the extent we are not able to obtain additional sources of capital on terms acceptable to us, we may modify our capital expenditure budget accordingly to reduce our capital spending and rate of growth, or enter into one or more joint ventures or other alternative financings.

Our cash flows for the nine months ended September 30, 2014 and 2013 are presented below:

	Nine Months Ended September 30,	
	2014	2013
(In thousands)	(Unaudited)	(Unaudited)
Net cash provided by operating activities	$180,359	$127,192
Net cash used in investing activities	(409,929)	(260,084)
Net cash provided by financing activities	231,006	137,127
Net change in cash	$1,436	$4,235
Adjusted EBITDA(1)	$192,624	$142,931

(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 $53.2 million to $180.4 million for the nine months ended September 30, 2014, as compared to net cash provided by operating activities of $127.2 million for the nine months ended September 30, 2013. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased by $49.2 million to $186.3 million for the nine months ended September 30, 2014 from $137.0 million for the nine months ended September 30, 2013. This increase is primarily attributable to the 38% increase in our oil and natural gas revenues between the respective periods. Changes in our operating assets and liabilities between September 30, 2013 and September 30, 2014 resulted in a net decrease of $3.9 million in net cash provided by operating activities for the nine months ended September 30, 2014.

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 where possible in order to minimize ongoing future commitments.

Cash Flows Used in Investing Activities

Net cash used in investing activities increased by $149.8 million to $409.9 million for the nine months ended September 30, 2014 from $260.1 million for the nine months ended September 30, 2013. 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, 2014, as compared to the nine months ended September 30, 2013. Cash used for oil and natural gas properties capital expenditures for the nine months ended September 30, 2014 was primarily attributable to our operated drilling and completion activities in the Eagle Ford shale play and our initial operated drilling activities in the Permian Basin, as well as the acquisition of additional leasehold interests in both operating areas. A small portion of our capital expenditures for the nine months ended September 30, 2014 was directed to our participation in non-operated wells, primarily in the Haynesville shale.

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Cash Flows Provided by Financing Activities

Net cash provided by financing activities was $231.0 million for the nine months ended September 30, 2014, as compared to net cash provided by financing activities of $137.1 million for the nine months ended September 30, 2013. The net cash provided by financing activities for the nine months ended September 30, 2014 was primarily attributable to the total proceeds of our May 2014 equity offering of $181.9 million and incremental borrowings under our Credit Agreement of $230.0 million, offset by the costs of the offering of $0.6 million and by the repayment of $180.0 million in borrowings during the period. The net cash provided by financing activities of $137.1 million for the nine months ended September 30, 2013 was attributable to the total proceeds of our September 2013 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.

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 (loss) or cash flows as determined by GAAP. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. Management believes Adjusted EBITDA is necessary because it allows us to evaluate our operating performance and compare the results of operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in calculating Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which certain assets were acquired.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In thousands)	2014	2013	2014	2013
Unaudited Adjusted EBITDA Reconciliation to Net Income:				
Net income	$29,619	$20,105	$64,208	$29,720
Interest expense	673	2,038	3,685	4,919
Total income tax provision	16,504	2,563	36,675	2,641
Depletion, depreciation and amortization	35,143	26,127	90,970	74,593
Accretion of asset retirement obligations	130	86	371	248
Full-cost ceiling impairment	—	—	—	21,229
Unrealized (gain) loss on derivatives	(16,293)	9,327	(7,950)	6,626
Stock-based compensation expense	1,038	1,239	4,665	2,763
Net loss on asset sales and inventory impairment	—	—	—	192
Adjusted EBITDA	$66,814	$61,485	$192,624	$142,931

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(In thousands)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:				
Net cash provided by operating activities	$66,883	$43,280	$180,359	$127,192
Net change in operating assets and liabilities	(586)	15,265	5,922	9,840
Interest expense	673	2,038	3,685	4,919
Current income tax (benefit) provision	(156)	902	2,658	980
Adjusted EBITDA	$66,814	$61,485	$192,624	$142,931

Our Adjusted EBITDA increased by $5.3 million to $66.8 million, or an increase of 9%, for the three months ended September 30, 2014, as compared to $61.5 million for the three months ended September 30, 2013. Our Adjusted EBITDA increased by $49.7 million to $192.6 million, or an increase of 35%, for the nine months ended September 30, 2014, as compared to $142.9 million for the nine months ended September 30, 2013. This increase in our Adjusted EBITDA is primarily attributable to the increase in our oil production and the associated increase in our oil and natural gas revenues for the three and nine months ended September 30, 2014, respectively, as compared to the three and nine months ended September 30, 2013, respectively.

Credit Agreement

On September 28, 2012, we entered into the Credit Agreement, which 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 proved oil and natural gas properties and by the equity interests of certain 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 certain 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 third quarter of 2014, the lenders completed their review of our estimated total proved oil and natural gas reserves at July 31, 2014, and as a result, on September 5, 2014, the borrowing base under our Credit Agreement was increased to $450.0 million, and the conforming borrowing base was increased to $375.0 million. This September 2014 redetermination constituted the regularly scheduled November 1 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.

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.

At September 30, 2014, we had $250.0 million in borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. For the three months ended September 30, 2014, our outstanding borrowings bore interest at an effective interest rate of approximately 2.9% per annum. From October 1, 2014 through November 5, 2014, we borrowed an additional $40.0 million under the Credit Agreement to finance a portion of our working capital requirements and capital expenditures. At November 5, 2014, we had $290.0 million in borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. We expect to access future borrowings under our Credit Agreement to fund our remaining 2014 capital expenditure requirements in excess of amounts available from our operating cash flows.

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, (ii) the Federal Funds Effective Rate (as defined in the Credit Agreement) on such day, plus 0.50% or (iii) the daily adjusting LIBOR rate (as defined in the Credit Agreement) plus 1.0% plus, in each case, an amount from 0.50% to 2.75%

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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 Royal Bank of Canada ("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 1.50% to 3.75% 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, if any, as interest expense and in our interest rate calculations and related disclosures. The Credit Agreement requires us to maintain a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.25 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.

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 outstanding borrowings 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, 2014, we believe that we were in compliance with the terms of the Credit Agreement.

Off-Balance Sheet Arrangements

At September 30, 2014, we did not have any off-balance sheet arrangements.

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Obligations and Commitments

We had the following material contractual obligations and commitments at September 30, 2014:

(In thousands)	Payments Due by Period 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)	$250,621	$621	$250,000	$—	$—
Office lease	7,148	851	1,781	1,863	2,653
Non-operated drilling commitments(2)	21,890	21,890	—	—	—
Drilling rig contracts(3)	57,887	19,279	38,608	—	—
Asset retirement obligations	11,291	540	1,214	1,633	7,904
Gas processing and transportation agreement(4)	6,869	3,119	3,750	—	—
Total contractual cash obligations	$355,706	$46,300	$295,353	$3,496	$10,557

(1) At September 30, 2014, we had $250.0 million in revolving borrowings outstanding under our Credit Agreement and approximately $0.6 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, 2014, 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 several of these wells were in progress at September 30, 2014. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of $21.9 million at September 30, 2014, which we expect to incur within the next few months.

(3) We do not own or operate our own drilling rigs, but instead enter into contracts with third parties for such rigs. These contracts establish daily rates for the drilling rigs and the term of our commitments for the drilling services to be provided, which have typically been for one year or less, although we have recently begun to enter into longer-term contracts in order to secure new drilling rigs equipped with the latest technology in plays that are experiencing heavy demand for drilling rigs. 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 $57.9 million at September 30, 2014.

(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 totaled approximately $6.9 million at September 30, 2014.

General Outlook and Trends

For the nine months ended September 30, 2014, oil prices ranged from a low of approximately $91.16 per Bbl in late September to a high of approximately $107.26 per Bbl in mid-June, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. We realized an average oil price of $95.45 per Bbl ($93.48 per Bbl including realized losses from oil derivatives) for our oil production for the nine months ended September 30, 2014, as compared to $103.34 per Bbl ($102.24 per Bbl including realized losses from oil derivatives) for the nine months ended September 30, 2013. Subsequent to September 30, 2014, oil prices have declined further, and at November 5, 2014, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date closed at $78.68 per Bbl as compared to $93.37 per Bbl at November 5, 2013. We are mindful of this recent decline in oil prices and are considering any adjustments that may be required to our operating plans and capital expenditures for

2015 as a result.

For the nine months ended September 30, 2014, natural gas prices ranged from a low of $3.75 per MMBtu in late July to a high of $6.15 per MMBtu in mid-February, 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 $5.53 per Mcf ($5.44 per Mcf including aggregate realized losses from natural gas and NGL derivatives) for our natural gas production for the nine months ended September 30, 2014, as compared to $4.20 per Mcf ($4.35 per Mcf including aggregate realized gains from natural gas and NGL derivatives) for the nine months ended September 30, 2013. The weighted average price we received for our natural gas during the nine months ended September 30, 2014 was higher than the NYMEX Henry Hub natural gas price due to the NGL volumes in the liquids-rich natural gas we produce primarily 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 2014 high in mid-February, natural gas prices have declined, and at November 5, 2014, the NYMEX

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Henry Hub natural gas futures contract for the earliest delivery date closed at $4.19 per MMBtu, as compared to $3.47 per MMBtu at November 5, 2013.

Most of our Eagle Ford shale oil production in South Texas is sold based on a Louisiana Light Sweet oil price index less transportation costs. Although we realized significant uplifts to West Texas Intermediate oil prices at times during 2013, the differential between these two benchmark prices has decreased substantially since early 2013. We may not realize similar, or any, uplifts to West Texas Intermediate oil prices in future periods, which could result in a decrease in our weighted average oil price realized and associated oil revenues. Additionally, oil production from our properties in the Permian Basin is sold on a West Texas Intermediate at Midland oil price index less transportation costs.

The prices we receive for oil, natural gas and natural gas liquids heavily influence our revenue, profitability, cash flow 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, at what price and what production 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 a material 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.

As we continue to explore and develop our acreage in the Permian Basin, we may face challenges associated with establishing operations in new areas and securing the necessary services to drill and complete wells and with securing the necessary pipeline and natural gas processing capabilities to transport, process and market the oil and natural gas that we produce. We may also incur higher than anticipated costs associated with establishing new operating infrastructure and facilities on our leases throughout the area. We believe we have successfully secured the necessary drilling services for our current Permian Basin operations. We have, at times, experienced difficulties in securing timely completion, and particularly certain hydraulic fracturing services, for wells drilled in the Permian Basin, as well as the Eagle Ford shale, and may have such difficulties again in the future. We believe that maintaining reliable drilling and completion services and reducing drilling and completion costs will be essential to the successful development of our Permian Basin leasehold as has been the case in the Eagle Ford shale and Haynesville shale plays.

Like other oil and natural gas producing companies, our properties are subject to natural production declines. By their nature, our oil and natural gas wells experience rapid initial production declines. We attempt to overcome these production declines by drilling to develop and identify additional reserves, by exploring for new sources of reserves and, at times, by acquisitions. During times of severe oil, natural gas and natural gas liquids price declines, however, drilling additional oil or natural gas wells may not be economical, and 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 strive to focus our efforts on increasing oil and natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our ability to find and develop sufficient quantities of oil and natural gas reserves at economical costs is critical to our long-term success. Future finding and development costs are subject to changes in the costs of acquiring, drilling and completing our prospects.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Except as set forth below, there have been no material changes to the sources and effects of our market risk since December 31, 2013, which are disclosed in the Annual Report.

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

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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 industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. At September 30, 2014, RBC, Comerica Bank, The Bank of Nova Scotia, BMO Harris Financing, Inc. (Bank of Montreal) and SunTrust Bank (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. See “Note 8 - Derivative Financial Instruments” to the unaudited condensed consolidated financial statements in this Quarterly Report for a summary of our open derivative financial instruments at September 30, 2014. Such information is incorporated herein by reference.

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, we evaluated 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”)) under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the Company’s disclosure controls and procedures were effective as of September 30, 2014 to ensure that (i) information required to be disclosed in the reports the Company files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and that (ii) information 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.

Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2014, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Part II—OTHER INFORMATION

Item 1. Legal Proceedings

We are party to a number of lawsuits arising in the ordinary course of business. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. For a discussion of such risks and uncertainties, please see "Item 1A. Risk Factors" in the Annual Report.

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 7, 2014	By:	/s/ Joseph Wm. Foran Joseph Wm. Foran Chairman and Chief Executive Officer
Date: November 7, 2014	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	Fifth Amendment to Third Amended and Restated Credit Agreement, dated as of September 5, 2014, 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 10.1 to the Current Report on Form 8-K filed on September 8, 2014).
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, 2014 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).