Matador Resources Co
Form 10-Q
August 10, 2015

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 June 30, 2015

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

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

As of August 4, 2015, there were 85,367,211 shares of the registrant’s common stock, par value $0.01 per share, outstanding.

MATADOR RESOURCES COMPANY
FORM 10-Q
FOR THE QUARTER ENDED JUNE 30, 2015
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Part I – FINANCIAL INFORMATION
Item 1. Financial Statements
Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED BALANCE SHEETS - UNAUDITED
(In thousands, except par value and share data)

	June 30, 2015	December 31, 2014
ASSETS		
Current assets		
Cash	$53,623	$ 8,407
Restricted cash	1,022	609
Accounts receivable		
Oil and natural gas revenues	34,250	28,976
Joint interest billings	19,830	6,925
Other	6,609	9,091
Derivative instruments	23,846	55,549
Lease and well equipment inventory	2,021	1,212
Prepaid expenses	3,803	1,649
Total current assets	145,004	112,418
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	1,938,008	1,617,913
Unproved and unevaluated	394,880	264,419
Other property and equipment	80,078	43,472
Less accumulated depletion, depreciation and amortization	(998,124)	(603,732)
Net property and equipment	1,414,842	1,322,072
Other assets	451	—
Total assets	$1,560,297	$ 1,434,490
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$14,443	$ 17,526
Accrued liabilities	122,421	109,502
Royalties payable	19,092	14,461
Advances from joint interest owners	447	—
Amounts due to Joint Ventures	2,250	—
Deferred income taxes	8,115	19,751
Income taxes payable	—	444
Other current liabilities	155	103
Total current liabilities	166,923	161,787
Long-term liabilities		
Borrowings under Credit Agreement	—	338,199
Senior unsecured notes payable	390,667	—
Asset retirement obligations	13,105	11,640
Amounts due to Joint Ventures	4,500	—
Derivative instruments	387	—
Deferred income taxes	25,645	53,783
Other long-term liabilities	2,723	2,540
Total long-term liabilities	437,027	406,162
Commitments and contingencies (Note 11)		

Shareholders' equity		
Common stock - $0.01 par value, 120,000,000 and 80,000,000 shares authorized; 85,450,478 and 73,373,744 shares issued; and 85,360,085 and 73,342,777 shares outstanding, respectively	855	734
Additional paid-in capital	1,021,117	724,819
Retained (deficit) earnings	(66,469)	140,855
Total Matador Resources Company shareholders' equity	955,503	866,408
Non-controlling interest in subsidiary	844	133
Total shareholders' equity	956,347	866,541
Total liabilities and shareholders' equity	$1,560,297	$ 1,434,490

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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Revenues				
Oil and natural gas revenues	$87,848	$99,054	$150,314	$177,986
Realized gain (loss) on derivatives	13,780	(2,913)	32,285	(4,756)
Unrealized loss on derivatives	(23,532)	(5,234)	(32,090)	(8,342)
Total revenues	78,096	90,907	150,509	164,888
Expenses				
Production taxes and marketing	10,258	9,116	17,308	15,122
Lease operating	14,950	11,704	27,996	21,055
Depletion, depreciation and amortization	51,768	31,797	98,239	55,827
Accretion of asset retirement obligations	132	123	244	241
Full-cost ceiling impairment	229,026	—	296,153	—
General and administrative	12,961	8,100	26,372	15,319
Total expenses	319,095	60,840	466,312	107,564
Operating (loss) income	(240,999)	30,067	(315,803)	57,324
Other income (expense)				
Net loss on asset sales and inventory impairment	—	—	(97)	—
Interest expense	(5,869)	(1,616)	(7,939)	(3,012)
Interest and other income	502	409	886	447
Total other expense	(5,367)	(1,207)	(7,150)	(2,565)
(Loss) income before income taxes	(246,366)	28,860	(322,953)	54,759
Income tax (benefit) provision				
Current	—	1,539	—	2,814
Deferred	(89,350)	9,095	(115,740)	17,356
Total income tax (benefit) provision	(89,350)	10,634	(115,740)	20,170
Net (loss) income	(157,016)	18,226	(207,213)	34,589
Net income attributable to non-controlling interest in subsidiary	(75)	—	(111)	—
Net (loss) income attributable to Matador Resources Company shareholders	$(157,091)	$18,226	$(207,324)	$34,589
Earnings (loss) per common share				
Basic	$(1.89)	$0.27	$(2.65)	$0.52
Diluted	$(1.89)	$0.26	$(2.65)	$0.51
Weighted average common shares outstanding				
Basic	82,938	68,531	78,379	67,108
Diluted	82,938	69,220	78,379	67,771

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

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Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY - UNAUDITED
(In thousands)
For the Six Months Ended June 30, 2015

	Common Stock Shares	Common Stock Amount	Preferred Stock Shares	Preferred Stock Amount	Additional paid-in capital	Retained (deficit) earnings	Treasury Stock Shares	Treasury Stock Amount	Total shareholders' equity attributable to Matador Resources Company	Non-controlling interest in subsidiary	Total shareholders' equity
Balance at January 1, 2015	73,374	$ 734	—	$ —	$ 724,819	$ 140,855	31	$ —	$ 866,408	$ 133	$ 866,541
Issuance of common stock	10,319	104	—	—	260,125	—	—	—	260,229	—	260,229
Issuance of preferred stock	—	—	150	1	32,489	—	—	—	32,490	—	32,490
Cost to issue equity	—	—	—	—	(1,172)	—	—	—	(1,172)	—	(1,172)
Conversion of preferred stock to common stock	1,500	15	(150)	(1)	(14)	—	—	—	—	—	—
Stock-based compensation expense related to equity-based awards	—	—	—	—	4,518	—	—	—	4,518	—	4,518
Stock options exercised	13	—	—	—	10	—	—	—	10	—	10
Liability-based stock option awards settled	10	—	—	—	343	—	—	—	343	—	343
Restricted stock issued	182	2	—	—	(2)	—	—	—	—	—	—
Restricted stock forfeited	—	—	—	—	—	—	59	—	—	—	—
Vesting of restricted stock units	52	—	—	—	1	—	—	—	1	—	1
Capital contribution to less than wholly owned subsidiary	—	—	—	—	—	—	—	—	—	600	600
Current period net (loss) income	—	—	—	—	—	(207,324)	—	—	(207,324)	111	(207,213)
Balance at June 30, 2015	85,450	$ 855	—	$ —	$ 1,021,117	$ (66,469)	90	$ —	$ 955,503	$ 844	$ 956,347

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)

	Six Months Ended June 30,	
	2015	2014
Operating activities		
Net (loss) income	$(207,213)	$34,589
Adjustments to reconcile net (loss) income to net cash provided by operating activities		
Unrealized loss on derivatives	32,090	8,342
Depletion, depreciation and amortization	98,239	55,827
Accretion of asset retirement obligations	244	241
Full-cost ceiling impairment	296,153	—
Stock-based compensation expense	5,131	3,629
Deferred income tax (benefit) provision	(115,740)	17,356
Net loss on asset sales and inventory impairment	97	—
Changes in operating assets and liabilities		
Accounts receivable	(12,161)	(13,338)
Lease and well equipment inventory	(269)	(36)
Prepaid expenses	(1,143)	(656)
Other assets	446	(468)
Accounts payable, accrued liabilities and other current liabilities	13,316	(517)
Royalties payable	4,253	5,890
Advances from joint interest owners	447	—
Income taxes payable	(444)	2,814
Other long-term liabilities	(56)	(198)
Net cash provided by operating activities	113,390	113,475
Investing activities		
Oil and natural gas properties capital expenditures	(237,027)	(234,335)
Expenditures for other property and equipment	(32,885)	(1,884)
Business combination, net of cash acquired	(23,671)	—
Restricted cash in less than wholly-owned subsidiaries	(413)	—
Net cash used in investing activities	(293,996)	(236,219)
Financing activities		
Repayments of borrowings	(476,982)	(180,000)
Borrowings under Credit Agreement	125,000	130,000
Proceeds from issuance of senior unsecured notes	400,000	—
Cost to issue senior unsecured notes	(8,789)	—
Proceeds from issuance of common stock	188,720	181,875
Cost to issue equity	(1,172)	(504)
Proceeds from stock options exercised	10	6
Capital commitment from non-controlling interest in subsidiary	600	—
Taxes paid related to net share settlement of stock-based compensation	(1,565)	(285)
Net cash provided by financing activities	225,822	131,092
Increase in cash	45,216	8,348
Cash at beginning of period	8,407	6,287
Cash at end of period	$53,623	$14,635

Supplemental disclosures of cash flow information (Note 12)

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 Wolfcamp and Bone Spring plays in the Permian (Delaware) Basin in Southeast New Mexico and West Texas and the Eagle Ford shale play in South 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, 2014 filed with the SEC (the “Annual Report”). The Company consolidates certain subsidiaries that are less than wholly-owned and the net income and equity attributable to the non-controlling interest in these subsidiaries have been reported separately as required by Accounting Standards Codification (“ASC”) 810. The Company proportionately consolidates certain joint ventures that are less than wholly-owned and are involved in oil and gas exploration. All intercompany accounts and transactions have been eliminated in consolidation. In management’s opinion, these interim unaudited condensed consolidated financial statements include all adjustments, consisting only of normal, recurring adjustments which are necessary for a fair presentation of the Company’s consolidated financial statements as of June 30, 2015. Amounts as of December 31, 2014 are derived from the audited consolidated financial statements in the Annual Report.
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.
Reclassifications
Certain reclassifications have been made to the 2014 financial statements in order to conform to the current year presentation. These reclassifications had no effect on previously reported results of operations, cash flows or retained earnings.
Change in Accounting Principle
The Company adopted Accounting Standards Update (“ASU”) 2015-03, Interest - Imputation of Interest (Subtopic 935-30): Simplifying the Presentation of Debt Issuance Costs, effective June 30, 2015. This standard requires companies that have historically presented debt issuance costs as an asset to present those costs as a direct deduction from the carrying amount of the underlying debt liability. To the extent that there are no borrowings under the Credit Agreement (as defined below), the related deferred loan costs will continue to be classified as an asset. The guidance required retrospective application in the financial statements. As such, the Company reclassified $1.8 million at

December 31, 2014 related to deferred loan costs for the Credit Agreement which had previously been presented in Prepaid Expenses and Other Assets. As the Company had no borrowings outstanding under the Credit Agreement at June 30, 2015, approximately $1.4 million of deferred loan costs related to the Credit Agreement are included in Prepaid Expenses and Other Assets. The Company’s senior unsecured notes are presented net of approximately $9.3 million of deferred loan costs at June 30, 2015. The Company had no senior unsecured notes outstanding at December 31, 2014.

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

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

Restricted Cash
Restricted cash represents the cash held by our less-than-wholly-owned subsidiaries. By contractual agreement, the cash in these accounts is not to be commingled with other Company cash and is to be used only to fund the capital expenditures and operations of these less-than-wholly-owned subsidiaries.
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 $1.9 million and $1.6 million of its general and administrative costs for the three months ended June 30, 2015 and 2014, respectively, and approximately $1.3 million and $0.7 million of its interest expense for the three months ended June 30, 2015 and 2014, respectively. The Company capitalized approximately $3.5 million and $2.8 million of its general and administrative costs for the six months ended June 30, 2015 and 2014, respectively, and approximately $2.3 million and $1.4 million of its interest expense for the six months ended June 30, 2015 and 2014, 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 the guidelines further dictate that a 10% discount factor be used to determine the present value of future net revenues. For the period from July 2014 through June 2015, these average oil and natural gas prices were $68.17 per barrel ("Bbl") and $3.39 per million British thermal units ("MMBtu"), respectively. For the period from July 2013 through June 2014, these average oil and natural gas prices were $96.75 per Bbl and $4.104 per MMBtu, respectively. In estimating the present value of after-tax future net cash flows from proved oil and natural gas reserves, the average oil prices were adjusted by property for quality, transportation and marketing fees and regional price differentials, and the average natural gas

prices were adjusted by property for energy content, transportation and marketing fees and regional price differentials. At June 30, 2015 and 2014, 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 June 30, 2015, the Company’s net capitalized costs less related deferred income taxes exceeded the full-cost ceiling

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

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

by $146.3 million. As a result, the Company recorded an impairment charge of $229.0 million to its net capitalized costs and a deferred income tax credit of $82.7 million related to the full-cost ceiling limitation at June 30, 2015. Using the average commodity prices, as adjusted, to determine the Company’s estimated proved oil and natural gas reserves at March 31, 2015, the Company’s net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $42.8 million. As a result, the Company recorded an impairment charge of $67.1 million to its net capitalized costs and a deferred income tax credit of $24.3 million related to the full-cost ceiling limitation at March 31, 2015. These charges are reflected in the Company’s unaudited condensed consolidated statement of operations for the six months ended June 30, 2015. Using the average commodity prices, as adjusted, to determine the Company’s estimated proved oil and natural gas reserves at June 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 and six months ended June 30, 2014.

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.

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.

Allocation of Purchase Price in Business Combinations

As part of the Company’s business strategy, it periodically pursues the acquisition of oil and natural gas properties. The purchase price in a business combination is allocated to the assets acquired and liabilities assumed based on their fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. The most significant estimates in the allocation typically relate to the value assigned to proved oil and natural gas reserves and unproved and unevaluated properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

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 six months ended June 30, 2015 and 2014 (in thousands).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Weighted average common shares outstanding				
Basic	82,938	68,531	78,379	67,108

Dilutive effect of options, restricted stock units and preferred shares	—	689	—	663
Diluted weighted average common shares outstanding	82,938	69,220	78,379	67,771

A total of 2.5 million options to purchase shares of the Company's common stock and 0.1 million restricted stock units were excluded from the calculations above for both the three and six months ended June 30, 2015, respectively, and zero and 1.5 million preferred shares were excluded from the calculations above for the three and six months ended June 30, 2015,

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NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

respectively, because their effects were anti-dilutive. Additionally, 0.7 million restricted shares, which are participating securities, were excluded from the calculations above for both the three and six months ended June 30, 2015, respectively, as the security holders do not have the obligation to share in the losses of the Company.

Recent Accounting Pronouncements

Revenue from Contracts with Customers. In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), which specifies how and when to recognize revenue. In addition, 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, 2017, i.e., in the Company’s first fiscal quarter of 2018. The Company is currently evaluating the impact, if any, of the adoption of this ASU on its consolidated financial statements.

NOTE 3 – BUSINESS COMBINATION

On February 27, 2015, the Company completed a business combination with Harvey E. Yates Company (“HEYCO”), a subsidiary of HEYCO Energy Group, Inc., through a merger of HEYCO with and into a wholly-owned subsidiary of Matador (the “HEYCO Merger”). In the HEYCO Merger, the Company obtained certain oil and natural gas producing properties and undeveloped acreage located in Lea and Eddy Counties, New Mexico, consisting of approximately 58,600 gross (18,200 net) acres strategically located between the Company’s existing acreage in its Ranger and Rustler Breaks prospect areas. HEYCO, headquartered in Roswell, New Mexico, was privately-owned prior to the transaction. As consideration for the business combination, Matador paid approximately $33.6 million in cash and assumed debt obligations and issued 3,300,000 shares of Matador common stock and 150,000 shares of a new series of Matador Series A Convertible Preferred Stock (“Series A Preferred Stock”) to HEYCO Energy Group, Inc. (convertible into ten shares of common stock for each one share of Series A Preferred Stock upon the effectiveness of an amendment to the Company’s Amended and Restated Certificate of Formation to increase the number of authorized shares of common stock; the Series A Preferred Stock converted to common stock on April 6, 2015). Matador paid an additional $3.0 million for customary purchase price adjustments, including adjusting for production, revenues and operating and capital expenditures from September 1, 2014 to closing. As a result of the HEYCO Merger, Matador incurred deferred tax liabilities of approximately $76.0 million and assumed other liabilities of approximately $4.6 million. The HEYCO Merger was accounted for using the acquisition method under ASC Topic 805, “Business Combinations,” which requires the assets acquired and liabilities assumed to be recorded at fair value as of the respective acquisition date. During the three and six months ended June 30, 2015, the Company incurred approximately $0.3 million and $2.5 million, respectively, of transaction costs associated with the HEYCO Merger. The majority of the assets acquired in the HEYCO Merger were in the form of non-producing acreage. The producing wells acquired in the HEYCO Merger did not have a material impact on the Company’s revenues or results of operations for the three and six months ended June 30, 2015.

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

NOTE 3 - BUSINESS COMBINATION - Continued

The allocation of the consideration given related to this business combination was as follows (in thousands).

Consideration given	Initial Allocation	Adjustments [1]	Adjusted Allocation
Cash	$24,648	$—	$24,648
Preferred shares issued	32,490	—	32,490
Common shares issued	71,478	—	71,478
Total consideration given	$128,616	$—	$128,616
Allocation of purchase price			
Cash acquired	$620	$—	$620
Accounts receivable	3,536	—	3,536
Inventory	180	—	180
Other current assets	106	—	106
Oil and natural gas properties			
Evaluated oil and natural gas properties	22,044	(5,520)	16,524
Unproved oil and unevaluated natural gas properties	194,686	6,835	201,521
Other property and equipment	—	178	178
Accounts payable	(2,551)	—	(2,551)
Accrued liabilities	(11)	(1,493)	(1,504)
Current note payable	(11,982)	—	(11,982)
Asset retirement obligations	(2,046)	—	(2,046)
Deferred tax liabilities incurred	(75,966)	—	(75,966)
Net assets acquired	$128,616	$—	$128,616

(1) These adjustments were the result of further analysis of the assets and liabilities acquired in the HEYCO Merger.

NOTE 4 - EQUITY

As discussed in Note 3, the Company issued 3,300,000 shares of common stock and 150,000 shares of a new series of Series A Preferred Stock to HEYCO Energy Group, Inc. in connection with the HEYCO Merger. Pursuant to the statement of resolutions, each share of Series A Preferred Stock would automatically convert into ten shares of Matador common stock, subject to customary anti-dilution adjustments, upon the vote and approval by Matador's shareholders of an amendment to Matador's Amended and Restated Certificate of Formation to increase the number of shares of authorized Matador common stock. Neither the issuance of the Series A Preferred Stock nor the common stock issued in connection with the HEYCO Merger were registered under the Securities Act of 1933, as amended, and neither the Series A Preferred Stock nor such common stock may be offered or sold in the United States absent such registration or an applicable exemption from registration requirements. As part of the HEYCO Merger, the Company entered into a registration rights agreement with HEYCO Energy Group, Inc. providing certain demand and piggyback registration rights, with demand registration rights exercisable beginning on February 27, 2016.

On April 2, 2015, the shareholders of the Company approved an amendment to the Company's Amended and Restated Certificate of Formation that authorized an increase in the number of authorized shares of common stock from 80,000,000 shares to 120,000,000 shares. Following such approval, the 150,000 outstanding shares of Series A Preferred Stock converted to 1,500,000 shares of common stock on April 6, 2015.

On April 21, 2015, the Company completed a public offering of 7,000,000 shares of its common stock. After deducting offering costs totaling approximately $1.1 million, the Company received net proceeds of approximately $187.5 million. The Company used a portion of the net proceeds to repay $85.0 million in outstanding borrowings under its revolving credit facility (see Note 6), which amounts may be reborrowed in accordance with the terms of that facility. The remaining $102.5 million of net proceeds is being used to fund a portion of the Company’s working capital expenditures, including the addition of a third

NOTE 4 - EQUITY - Continued

drilling rig in the Permian Basin in late July 2015 and targeted acquisitions of additional acreage in the Permian Basin, as well as in the Eagle Ford shale and the Haynesville shale, and for other general working capital needs.

All shares of treasury stock outstanding at June 30, 2015 and December 31, 2014 represent forfeitures of non-vested restricted stock awards.

NOTE 5 - ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company's asset retirement obligations for the six months ended June 30, 2015 (in thousands).

Beginning asset retirement obligations	$11,951
Liabilities incurred during period	2,357
Liabilities settled during period	(252)
Revisions in estimated cash flows	(920)
Accretion expense	244
Ending asset retirement obligations	13,380
Less: current asset retirement obligations(1)	(275)
Long-term asset retirement obligations	$13,105

(1) Included in accrued liabilities in the Company's unaudited condensed consolidated balance sheet at June 30, 2015.

NOTE 6 - DEBT

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 is the borrower under the Credit Agreement and is a subsidiary of Matador that, at June 30, 2015, directly or indirectly owned all of the ownership interests in the Company's other operating subsidiaries other than its less-than-wholly-owned subsidiaries. Borrowings are secured by mortgages on at least 80% of the Company's proved oil and natural gas properties and by the equity interests 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 second quarter of 2015, the lenders completed their review of the Company's estimated total proved oil and natural gas reserves at December 31, 2014, and as a result, on April 6, 2015, the Company received notice that the borrowing base under the Credit Agreement would be reaffirmed at $450.0 million, and the conforming borrowing base would be reaffirmed at $375.0 million. Pursuant to an amendment to the Credit Agreement entered into concurrently with the issuance of $400.0 million of senior unsecured notes on April 14, 2015 discussed herein, the borrowing base was reduced to the conforming borrowing base of $375.0 million.

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 associated with the Credit Agreement were $1.4 million at June 30, 2015, 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 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.

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NOTE 6 - DEBT - Continued

At June 30, 2015, the Company had no borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. During the three months ended June 30, 2015, using a portion of the net proceeds from the senior unsecured notes offering and public offering of common stock discussed herein, the Company repaid a total of $465.0 million of its outstanding borrowings under the Credit Agreement. For the three months ended June 30, 2015, the Company's outstanding borrowings under the Credit Agreement bore interest at an effective interest rate of approximately 3.7% per annum. At August 4, 2015, the Company continued to have no 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 1.50% 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 2.50% 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 (as defined in the Credit Agreement) 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;
- engage in certain asset dispositions, including a sale of all or substantially all of the Company's assets; and
- take certain actions with respect to the Company's senior unsecured notes.

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

At June 30, 2015, the Company believes that it was in compliance with the terms of the Credit Agreement.

NOTE 6 - DEBT - Continued

Senior Unsecured Notes

On April 14, 2015, Matador issued $400.0 million of 6.875% senior notes due 2023 (the “Notes”). The Notes are Matador’s senior unsecured obligations, are redeemable as described below and were issued at par value. The net proceeds were used to pay down a portion of the outstanding borrowings under the Credit Agreement and the debt assumed in connection with the HEYCO Merger. The Notes mature on April 15, 2023, and interest is payable semi-annually in arrears on April 15 and October 15 of each year. The Notes are guaranteed on a senior unsecured basis by all of Matador’s wholly-owned subsidiaries.

On or after April 15, 2018, Matador may redeem all or a portion of the Notes at any time or from time to time at the following redemption prices (expressed as percentages of the principal amount) plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the twelve month period beginning on April 15 of the years indicated.

Year	Redemption Price
2018	105.156%
2019	103.438%
2020	101.719%
2021 and thereafter	100.000%

At any time prior to April 15, 2018, Matador may redeem up to 35% of the aggregate principal amount of the Notes with net proceeds from certain equity offerings at a redemption price of 106.875% of the principal amount of the Notes, plus accrued and unpaid interest, if any, to the redemption date; provided that (i) at least 65% in aggregate principal amount of the Notes (including any additional notes) originally issued remains outstanding immediately after the occurrence of such redemption (excluding Notes held by Matador and its subsidiaries) and (ii) each such redemption occurs within 180 days of the date of the closing of the related equity offering.

In addition, at any time prior to April 15, 2018, Matador may redeem all or part of the Notes at a redemption price equal to the sum of:

(i) the principal amount thereof, plus

(ii) the excess, if any, of (a) the present value at such time of (1) the redemption price of such Notes at April 15, 2018 plus (2) any required interest payments due on such Notes through April 15, 2018 discounted to the redemption date on a semi-annual basis using a discount rate equal to the Treasury Rate (as defined in the indenture governing the Notes (the “Indenture”)) plus 50 basis points, over (b) the principal amount of such Notes, plus

(iii) accrued and unpaid interest, if any, to the redemption date.

Subject to certain exceptions, the Indenture contains various covenants that limit the Company’s ability to take certain actions, including, but not limited to, the following:

- incur or guarantee additional debt or issue certain types of preferred stock;
- pay dividends on capital stock or redeem, repurchase or retire its capital stock or subordinated indebtedness;
- transfer or sell assets;
- make certain investments;
- create certain liens;
- enter into agreements that restrict dividends or other payments from its Restricted Subsidiaries (as defined in the Indenture) to the Company;
- consolidate, merge or transfer all or substantially all of its assets;
- engage in transactions with affiliates; and
- create unrestricted subsidiaries.

In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to Matador, any Restricted Subsidiary that is a Significant Subsidiary (as defined in the Indenture) or any group of Restricted

Subsidiaries that, taken together, would constitute a Significant Subsidiary, all outstanding Notes will become due and payable immediately

NOTE 6 - DEBT - Continued

without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding Notes may declare all the Notes to be due and payable immediately. Events of default include, but are not limited to, the following events:

- default for 30 days in the payment when due of interest on the Notes;
- default in the payment when due of the principal of, or premium, if any, on the Notes;
- failure by Matador to comply with its obligations to offer to purchase or purchase Notes when required pursuant to the change of control or asset sale provisions of the Indenture or Matador's failure to comply with the covenant relating to merger, consolidation or sale of assets;
- failure by Matador for 180 days after notice to comply with its reporting obligations under the Indenture;
- failure by Matador for 60 days after notice to comply with any of the other agreements in the Indenture;
- payment defaults and accelerations with respect to other indebtedness of Matador and its Restricted Subsidiaries in the aggregate principal amount of $25.0 million or more;
- failure by Matador or any Restricted Subsidiary to pay certain final judgments aggregating in excess of $25.0 million within 60 days;
- any subsidiary guarantee by a guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker; and
- certain events of bankruptcy or insolvency with respect to Matador or any Restricted Subsidiary that is a Significant Subsidiary or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary.

Note Payable

In connection with the HEYCO Merger, the Company assumed a note payable to PlainsCapital Bank in the amount of $12.5 million pursuant to which approximately $12.0 million of indebtedness was outstanding. The outstanding indebtedness was repaid on April 14, 2015 using a portion of the net proceeds from the Notes offering, and the related credit agreement and all associated obligations were terminated.

NOTE 7 - INCOME TAXES

The Company had an effective tax rate of 36.3% and 35.8% for the three and six months ended June 30, 2015, respectively. The Company had an effective tax rate of 36.8% and 36.8% for the three and six months ended June 30, 2014, respectively. Total income tax benefit or provision for the three and six months ended June 30, 2015 and 2014 differed from amounts computed by applying the U.S. federal statutory tax rate to income (loss) before income taxes due primarily to state tax apportionments and nondeductible expenses. The total income tax benefit of $89.4 million and $115.7 million for the three and six months ended June 30, 2015 included $82.7 million and $107.0 million, respectively, of deferred income tax benefit resulting from full-cost ceiling impairments. Based upon its projections during 2014, the Company anticipated incurring a small alternative minimum tax ("AMT") liability for the year ending December 31, 2014, the proportionate share of which was recorded as the current income tax provision for the three and six months ended June 30, 2014.

NOTE 8 - STOCK-BASED COMPENSATION

In January 2015, the Company granted awards of 113,289 shares of restricted stock and options to purchase 607,995 shares of the Company's common stock at an exercise price of $22.01 to certain of its employees. The fair value of these awards at the date of grant was approximately $8.4 million. In August 2015, the Company granted an award of 182,250 shares of restricted stock to certain of its employees. The fair value of these awards on the date of grant was approximately $4.1 million. All of these awards vest over a term of three years.

NOTE 9 - 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 (“NGL”) prices. These instruments consist of put and call options in the form of costless collar 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 and BMO Harris Financing (Bank of Montreal) (or affiliates thereof) were the counterparties for the Company’s commodity derivatives at June 30, 2015. 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 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 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 June 30, 2015, 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 2015 and 2016.

At June 30, 2015, 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 2015.

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NOTE 9 - 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 June 30, 2015.

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil	07/01/2015 - 12/31/2015	40,000	45.00	68.75	$(161)
Oil	07/01/2015 - 12/31/2015	50,000	50.00	67.85	(110)
Oil	07/01/2015 - 12/31/2015	20,000	80.00	100.00	2,376
Oil	07/01/2015 - 12/31/2015	20,000	80.00	101.00	2,377
Oil	07/01/2015 - 12/31/2015	20,000	83.00	96.12	2,726
Oil	07/01/2015 - 12/31/2015	20,000	83.00	97.00	2,725
Oil	07/01/2015 - 12/31/2015	20,000	85.00	99.00	2,963
Oil	07/01/2015 - 12/31/2015	20,000	85.00	100.00	2,963
Oil	07/01/2015 - 12/31/2015	20,000	85.00	105.10	2,964
Oil	07/01/2015 - 12/31/2016	40,000	55.00	68.35	156
Oil	01/01/2016 - 12/31/2016	40,000	43.00	77.05	(266)
Oil	07/01/2016 - 12/31/2016	50,000	45.00	77.75	(77)
Total open oil costless collar contracts					18,636

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas	07/01/2015 - 10/31/2015	150,000	2.75	3.19	29
Natural Gas	07/01/2015 - 12/31/2015	100,000	2.75	3.05	(19)
Natural Gas	07/01/2015 - 12/31/2015	100,000	2.75	3.15	(2)
Natural Gas	07/01/2015 - 12/31/2015	100,000	2.75	3.11	(8)
Natural Gas	07/01/2015 - 12/31/2015	300,000	2.88	3.18	128
Natural Gas	07/01/2015 - 12/31/2015	100,000	3.75	4.36	523
Natural Gas	07/01/2015 - 12/31/2015	100,000	3.75	4.45	524
Natural Gas	07/01/2015 - 12/31/2015	100,000	3.75	4.60	526
Natural Gas	07/01/2015 - 12/31/2015	100,000	3.75	4.65	518
Natural Gas	07/01/2015 - 12/31/2015	200,000	3.75	5.04	1,057
Natural Gas	07/01/2015 - 12/31/2015	100,000	3.75	5.34	529
Natural Gas	01/01/2016 - 12/31/2016	200,000	2.75	3.50	(164)
Natural Gas	01/01/2016 - 12/31/2016	200,000	2.75	3.86	38
Natural Gas	01/01/2016 - 12/31/2016	300,000	2.75	3.95	118
Total open natural gas costless collar contracts					3,797

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NOTE 9 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

Commodity	Calculation Period	Notional Quantity (Gal/month)	Fixed Price ($/Gal)	Fair Value of Asset (Liability) (thousands)
Propane	07/01/2015 - 12/31/2015	150,000	1.000	462
Propane	07/01/2015 - 12/31/2015	100,000	1.030	326
Propane	07/01/2015 - 12/31/2015	68,000	1.073	239
Total open NGL swap contracts				1,027
Total open derivative financial instruments				$23,460

These derivative financial instruments are subject to master netting arrangements; all but one counterparty 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. The following table presents the gross asset and liability fair values of the Company’s commodity price derivative financial instruments and the location of these balances in the unaudited condensed consolidated balance sheet as of June 30, 2015 and December 31, 2014 (in thousands).

Derivative Instruments	Gross amounts recognized	Gross amounts netted in the condensed consolidated balance sheets	Net amounts presented in the condensed consolidated balance sheets
June 30, 2015			
Current assets	$27,731	$(3,885)	$23,846
Other assets	2,872	(2,871)	1
Current liabilities	(3,885)	3,885	—
Other liabilities	(3,258)	2,871	(387)
Total	$23,460	$—	$23,460
December 31, 2014			
Current assets	$56,255	$(706)	$55,549
Current liabilities	(706)	706	—
Total	$55,549	$—	$55,549

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NOTE 9 - 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 June 30,		Six Months Ended June 30,	
Type of Instrument	Location in Condensed Consolidated Statement of Operations	2015	2014	2015	2014
Derivative Instrument					
Oil	Revenues: Realized gain (loss) on derivatives	$10,524	$(2,764)	$24,957	$(3,706)
Natural Gas	Revenues: Realized gain (loss) on derivatives	2,716	(187)	6,315	(776)
NGL	Revenues: Realized gain (loss) on derivatives	540	38	1,013	(274)
Realized gain (loss) on derivatives		13,780	(2,913)	32,285	(4,756)
Oil	Revenues: Unrealized loss on derivatives	(19,880)	(5,701)	(26,345)	(7,751)
Natural Gas	Revenues: Unrealized (loss) gain on derivatives	(3,281)	698	(4,843)	(569)
NGL	Revenues: Unrealized loss on derivatives	(371)	(231)	(902)	(22)
Unrealized loss on derivatives		(23,532)	(5,234)	(32,090)	(8,342)
Total		$(9,752)	$(8,147)	$195	$(13,098)

NOTE 10 - 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 in the fair value hierarchy:

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.

NOTE 10 - FAIR VALUE MEASUREMENTS - Continued

The following tables summarize the valuation of the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis in accordance with the classifications provided above as of June 30, 2015 and December 31, 2014 (in thousands).

	Fair Value Measurements at June 30, 2015 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Oil, natural gas and NGL derivatives	$—	$23,847	$—	$23,847
Oil, natural gas and NGL derivatives	—	(387)	—	(387)
Total	$—	$23,460	$—	$23,460

	Fair Value Measurements at December 31, 2014 using			
Description	Level 1	Level 2	Level 3	Total
Assets				
Oil, natural gas and NGL derivatives	$—	$55,549	$—	$55,549
Total	$—	$55,549	$—	$55,549

Additional disclosures related to derivative financial instruments are provided in Note 9.

Other Fair Value Measurements

At June 30, 2015 and December 31, 2014, the carrying values reported on the unaudited condensed consolidated balance sheets for accounts receivable, prepaid expenses, accounts payable, accrued liabilities, royalties payable, advances from joint interest owners, amounts due to joint ventures, income taxes payable and other current liabilities approximate their fair values due to their short-term maturities.

At June 30, 2015 and December 31, 2014, the carrying value of borrowings under the Credit Agreement approximates fair value as it is subject to short-term floating interest rates, which represent Level 2 inputs in the fair value hierarchy and reflect market rates available to the Company at the time.

At June 30, 2015, the fair value of the Company's Notes was $408.5 million based on quoted market prices, which represent Level 1 inputs in the fair value hierarchy. The Company had no Notes outstanding at December 31, 2014.

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NOTE 11 - COMMITMENTS AND CONTINGENCIES

Office Lease
The Company leases office facilities under operating leases. In June 2015, the Company entered into the seventh amendment of its Dallas corporate office lease agreement. This amendment increased the Company's total leased space from approximately 40,000 square feet to approximately 100,000 square feet effective January 2016.
From time to time, the Company also enters into leases for field offices in locations where the Company has active field operations. These leases are typically for terms of less than five years and are not considered principal properties.
The following is a schedule of future minimum lease payments required under all office lease agreements as of June 30, 2015 for the remaining six months of 2015, the twelve months ending December 31, 2016, 2017, 2018 and 2019, and all periods thereafter (in thousands).

	Amount
2015	$447
2016	2,017
2017	2,432
2018	2,488
2019	2,528
Thereafter	17,597
Total	$27,509

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 NGL 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 $4.5 million at June 30, 2015. The Company paid $1.4 million and $1.7 million in processing and transportation fees under this agreement during the three months ended June 30, 2015 and 2014, respectively, and $2.7 million and $2.8 million in processing and transportation fees under this agreement during the six months ended June 30, 2015 and 2014, 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 were until recently 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 $43.8 million at June 30, 2015.

The Company entered into an agreement in 2014 with a third party for the engineering, procurement, construction and installation of a natural gas processing plant in Loving County, Texas. This plant is expected to process a portion of the

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

NOTE 11 - COMMITMENTS AND CONTINGENCIES - Continued

Company's natural gas produced from certain of its wells in the Permian Basin, as well as third-party natural gas once the plant is completed. Total commitments under this contract are $17.0 million, and the Company made payments totaling $6.8 million and $12.0 million during the three and six months ended June 30, 2015, respectively. The Company made no payments under this contract during the three and six months ended June 30, 2014. The plant is scheduled to be completed and placed in service in the third quarter of 2015.

At June 30, 2015, 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 $22.8 million at June 30, 2015, which the Company 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 condition, results of operations or cash flows.

NOTE 12 - SUPPLEMENTAL DISCLOSURES

Accrued Liabilities

The following table summarizes the Company's current accrued liabilities at June 30, 2015 and December 31, 2014 (in thousands).

	June 30, 2015	December 31, 2014
Accrued evaluated and unproved and unevaluated property costs	$77,662	$86,259
Accrued support equipment and facilities costs	8,149	4,290
Accrued lease operating expenses	11,594	9,034
Accrued interest on borrowings under the Credit Agreement and the Notes	5,882	206
Accrued asset retirement obligations	275	311
Accrued partners' share of joint interest charges	8,811	3,767
Other	10,048	5,635
Total accrued liabilities	$122,421	$109,502

Supplemental Cash Flow Information

The following table provides supplemental disclosures of cash flow information for the six months ended June 30, 2015 and 2014 (in thousands).

	Six Months Ended June 30,	
	2015	2014
Cash paid for interest expense, net of amounts capitalized	$2,263	$3,058
Asset retirement obligations related to mineral properties	$1,212	$2,343
Asset retirement obligations related to support equipment and facilities	$41	$132
(Decrease) increase in liabilities for oil and natural gas properties capital expenditures	$(9,909)	$34,444
Increase in liabilities for support equipment and facilities	$3,859	$293
Stock-based compensation expense recognized as liability	$583	$1,200
Transfer of inventory from oil and natural gas properties	$456	$133

NOTE 13 - 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 and guarantees of debt securities by certain subsidiaries of Matador (the "Shelf Guarantor Subsidiaries"). On April 14, 2015, the Company issued the Notes (see Note 6), which are jointly and severally guaranteed by certain subsidiaries of Matador (the "Notes Guarantor Subsidiaries" and, together with the Shelf Guarantor Subsidiaries, the "Guarantor Subsidiaries") on a full and unconditional basis (except for customary release provisions). On June 1, 2015, Matador filed a registration statement on Form S-4 with the SEC in connection with the exchange of the Notes for notes with substantially identical terms that are registered under the Securities Act, including guarantees by each of the Notes Guarantor Subsidiaries. As of June 30, 2015, the Guarantor Subsidiaries are 100% owned by Matador, and any subsidiaries of Matador other than the Guarantor Subsidiaries are minor. Matador is a parent holding company and has no independent assets or operations, and there are no significant restrictions on the ability of Matador to obtain funds from the Guarantor Subsidiaries by dividend or loan.

NOTE 14 - RELATED PARTY TRANSACTIONS

In June 2015, the Company entered into two joint ventures to develop certain leasehold interests held by certain affiliates (the "HEYCO Affiliates") of HEYCO Energy Group, Inc., the former parent company of HEYCO. The HEYCO Affiliates are owned by George M. Yates, who is a member of the Company's Board of Directors, and certain of his affiliates. Pursuant to the terms of the transaction, the HEYCO Affiliates contributed an aggregate of approximately 1,900 net acres, primarily in the same properties previously held by HEYCO, to the two newly-formed entities in exchange for a 50% interest in each entity. The Company has agreed to contribute an aggregate of $14.2 million in exchange for the other 50% interest in both entities. As of June 30, 2015, the Company had contributed an aggregate of approximately $0.7 million to the two entities. The Company's contributions will be used to fund future capital expenditures associated with the interests being acquired as well as to fund acquisitions of other non-operated acreage opportunities.

Additionally, substantially all of the oil production from the wells acquired in the HEYCO Merger is subject to pre-existing sales contracts with an entity owned by affiliates of HEYCO Energy Group, Inc. The Company recorded revenue of $0.7 million for oil sold pursuant to such contracts for the six months ended June 30, 2015.

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, 2014 (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.

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Such factors include, among others: the integration of the assets, employees and operations of Harvey E. Yates Company following its merger with one of our wholly-owned subsidiaries on February 27, 2015, 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;
- government regulation and taxation of the oil and natural gas industry;
- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- the integration of Harvey E. Yates Company with our business;
- 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

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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 Wolfcamp and Bone Spring plays in the Permian (Delaware) Basin in Southeast New Mexico and West Texas and the Eagle Ford shale play in South Texas. We also operate in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas.

Second Quarter and Year-to-Date Highlights

Quarterly production results for the second quarter of 2015 were the best in our Company's history. Our total oil equivalent production for the second quarter of 2015 was 2.42 million BOE, and our average daily oil equivalent production for the second quarter of 2015 was 26,601 BOE per day, of which 13,847 Bbl per day, or 52%, was oil and 76.5 MMcf per day, or 48%, was natural gas, each component of which were also record quarterly results. For the six months ended June 30, 2015, our total oil equivalent production was 4.54 million BOE, averaging 25,066 BOE per day, our total oil production was 2.27 million Bbl, averaging 12,534 Bbl per day, and our total natural gas production was 13.6 Bcf, averaging 75.2 MMcf per day. These results were also the best results for any six-month period in our Company's history.

During the second quarter of 2015, our oil and natural gas revenues were $87.8 million, a decrease of 11% from oil and natural gas revenues of $99.1 million during the second quarter of 2014. This decrease was attributable to a sharp decline in the weighted average oil and natural gas prices to $54.37 per Bbl and $2.78 per Mcf, respectively, realized in the second quarter of 2015 from weighted average oil and natural gas prices of $97.92 per Bbl and $5.69 per Mcf, respectively, realized in the second quarter of 2014. The decrease in our oil and natural gas revenues was mitigated by the 57% increase in our oil production to 1.26 million Bbl in the second quarter of 2015, as compared to 802,000 Bbl produced in the second quarter of 2014, and by the 93% increase in our natural gas production to 7.0 Bcf in the second quarter of 2015, as compared to 3.6 Bcf in the second quarter of 2014. The increase in oil production was primarily a result of our ongoing and better-than-expected performance of wells drilled and completed in the Delaware Basin, as well as from newly drilled and completed wells in the Eagle Ford shale in early 2015. The increase in natural gas production was primarily attributable to new, non-operated Haynesville shale wells completed and placed on production on our Elm Grove properties in Northwest Louisiana in the latter half of 2014 and into 2015, but also includes increased natural gas production associated with our operations in the Delaware Basin. For the three months ended June 30, 2015, our Adjusted EBITDA was $66.7 million, a decrease of 4% from Adjusted EBITDA of $69.5 million during the three months ended June 30, 2014.

For the six months ended June 30, 2015, our oil and natural gas revenues were $150.3 million, a decrease of 16% from oil and natural gas revenues of $178.0 million for the first six months of 2014. This decrease was attributable to a sharp decline in the weighted average oil and natural gas prices to $49.48 per Bbl and $2.80 per Mcf, respectively, realized in the six months ended June 30, 2015 from weighted average oil and natural gas prices of $97.20 per Bbl and $5.90 per Mcf, respectively, realized in the six months ended June 30, 2014. The decrease in our oil and natural gas revenues was mitigated by the 55% increase in our oil production to 2.27 million Bbl in the six months ended June 30, 2015, as compared to 1.46 million Bbl produced in the six months ended June 30, 2014, and by a 124% increase in our natural gas production to 13.6 Bcf for the six months ended June 30, 2015, as compared to 6.1 Bcf for the six months ended June 30, 2014. This increase in oil and natural gas production was attributable to the same operations noted above for the three months ended June 30, 2015 and 2014. For the six months ended June 30, 2015, our Adjusted EBITDA was $116.8 million, a decrease of 7% from Adjusted EBITDA of $125.8 million for the six months ended June 30, 2014.

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 2015, see “— Results of Operations” below.

On February 27, 2015, we completed a business combination with Harvey E. Yates Company (“HEYCO”), a subsidiary of HEYCO Energy Group, Inc., through which we obtained certain oil and natural gas producing properties and undeveloped acreage, totaling approximately 58,600 gross (18,200 net) acres, strategically located between our existing acreage in our Ranger and Rustler Breaks prospect areas in Lea and Eddy Counties, New Mexico (the “HEYCO Merger”). As consideration for the HEYCO Merger, we paid approximately $24.6 million in cash, including customary closing adjustments, assumed debt obligations of approximately $12.0 million (the "Assumed Indebtedness") and issued 3,300,000 shares of the Company's common stock and 150,000 shares of a new series of Matador's Series A Convertible Preferred Stock (the "Series A Preferred Stock") to HEYCO Energy Group, Inc. Each share of Series A Preferred Stock converted into ten shares of our common stock on April 6, 2015 following the vote and approval by our shareholders of an amendment to our Amended and Restated Certificate of Formation to increase the number of shares of authorized common stock (the "Charter Amendment") and the receipt of evidence of the filing of the Charter Amendment with the Texas Secretary of State.

On June 5, 2015, we entered into joint ventures with certain affiliates of HEYCO Energy Group, Inc. (the "HEYCO Affiliates"). The HEYCO Affiliates contributed approximately 1,900 net acres, primarily additional working interests in the same properties previously held by HEYCO, to two newly-formed entities in exchange for a 50% interest in each entity. We agreed to contribute an aggregate of $14.2 million in exchange for the other 50% interest in both entities. Our contribution will be used to fund future capital expenditures associated with the interests being acquired as well as to fund acquisitions of other non-operated acreage opportunities. Including the interests acquired in the joint ventures with the HEYCO Affiliates and the approximately 58,600 gross (18,200 net) acres in Lea and Eddy Counties, New Mexico acquired in the HEYCO Merger, at August 4, 2015 our total acreage position in the Permian Basin in Southeast New Mexico and West Texas was 156,500 gross (89,600 net) acres.

At March 31, 2015, we had borrowings outstanding of $410.0 million and $0.6 million in letters of credit issued under our third amended and restated credit agreement (the "Credit Agreement"). On April 6, 2015, we received notice that the borrowing base under our Credit Agreement would be reaffirmed at $450.0 million, and the conforming borrowing base would be reaffirmed at $375.0 million, based on our lenders' review of our proved oil and natural gas reserves at December 31, 2014.

On April 14, 2015, we issued $400.0 million in 6.875% senior notes due 2023 (the "Notes"). The Notes are our senior unsecured obligations and were issued at par value. The net proceeds were used to pay $380.0 million in outstanding borrowings under our Credit Agreement, which amounts may be reborrowed in accordance with the terms of that facility, and $12.0 million in Assumed Indebtedness.

Subsequent to the issuance of the Notes, we borrowed $55.0 million under the Credit Agreement to finance a portion of our working capital and capital expenditure requirements and for the acquisition of additional leasehold interests.

On April 21, 2015, we completed a public offering of 7,000,000 shares of our common stock. After deducting direct offering costs totaling approximately $1.1 million, we received net proceeds of approximately $187.5 million. We used a portion of the net proceeds to repay the remaining $85.0 million in outstanding borrowings under our Credit Agreement, which amounts may be reborrowed in accordance with the terms of that facility. The remaining $102.5 million of net proceeds has been and is being used to fund a portion of our capital expenditures, including the addition of a third drilling rig in the Permian Basin in late July 2015 and targeted acquisitions of additional acreage in the Permian Basin, as well as in the Eagle Ford shale and the Haynesville shale, and for other general working capital needs.

At June 30, 2015 and August 4, 2015, we had no borrowings outstanding under our Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to our Credit Agreement.

At the beginning of 2015, we were operating five drilling rigs, two rigs in the Eagle Ford and three rigs in the Permian (Delaware) Basin, but we reduced our operated drilling rigs to two by the end of the first quarter of 2015, with both operating in the Delaware Basin. In late July 2015, we took delivery of a third drilling rig which has begun drilling in our Jackson Trust prospect area in northeast Loving County, Texas testing the Second Bone Spring and shallower targets. Following the conclusion of those operations, the rig is scheduled to drill in our Ranger and Arrowhead prospect areas (including acreage acquired in the HEYCO Merger) in northern Eddy and Lea Counties, New Mexico to further delineate the Bone Spring and Wolfcamp potential in those areas. We are currently operating three drilling rigs in the Delaware Basin, two in Loving County, Texas and one in Eddy County, New Mexico. We have completed our planned operated drilling and completion activities in the Eagle Ford shale for 2015. We expect to continue to participate in several non-operated Haynesville shale wells drilled by a subsidiary of Chesapeake Energy Corporation ("Chesapeake") and other operating partners during the remainder of 2015.

Primarily as a result of beginning to drill wells faster, increased working interests on certain operated wells, additional participation in non-operated wells proposed on our acreage and an increased focus on drilling more, deeper Wolfcamp wells in the Delaware Basin (as opposed to shallower Bone Spring wells) than originally planned for 2015, as well as due to the addition of a third drilling rig in the Delaware Basin beginning in late July 2015, additional capital allocated to the acquisition of oil and natural gas leases and additional midstream investments, on August 4, 2015, we raised our estimated 2015 capital expenditure budget from $350 million to $425 million (excluding capital expenditures associated with the HEYCO Merger). We expect to fund our remaining 2015 capital expenditure budget through a combination of cash on hand, operating cash flows, borrowings under our Credit Agreement, potential joint ventures and the potential sale of assets or acreage. At June 30, 2015, we had incurred $266 million, or approximately 63%, of our increased 2015 capital expenditure budget of $425.0 million (excluding capital expenditures associated with the HEYCO Merger).

During the second quarter of 2015, we completed and began producing oil and natural gas from 14 gross (7.6 net) wells in the Permian Basin, including nine gross (7.4 net) operated wells and five gross (0.2 net) non-operated wells, throughout our various prospect areas. As a result of our ongoing drilling and completion operations in these prospect areas, our Permian Basin production has continued to increase over the past twelve months. Our total Permian Basin production for the second quarter of 2015 was 6,187 BOE per day, consisting of 4,468 Bbl of oil per day and 10.3 MMcf of natural gas per day, a 4.5-fold increase from production of 1,361 BOE per day, consisting of 959 Bbl of oil per day and 2.4 MMcf of natural gas per day, in the second quarter of 2014. The Permian Basin contributed approximately 32% of our daily oil production and approximately 13% of our daily natural gas production in the second quarter of 2015, as compared to only about 11% of our daily oil production and approximately 6% of our daily natural gas production in the second quarter of 2014.

We continue to make significant progress in reducing drilling costs and times for both Wolfcamp and Bone Spring horizontal wells. We have especially focused on ways to improve drilling times and operational efficiencies and have cut drilling times by as much as 50% on recent Wolfcamp wells in the Wolf and Rustler Breaks prospect areas as compared to early wells drilled in these prospect areas. We continue to improve operational efficiencies in completions and production operations as well by developing new completions practices, implementing gas lift and other artificial lift technologies and increasing our midstream capabilities, among other operational enhancements.

In the Wolf prospect area in Loving County, Texas, for example, Wolfcamp drilling times (spud to total depth) have been reduced from an average of 43 days in 2014 to as low as 23 days on recent wells. In the Rustler Breaks prospect area in Eddy County, New Mexico, where the Wolfcamp formation is shallower, Wolfcamp drilling times have been reduced from an average of 32 days in 2014 and early 2015 to as low as 15 days on recent wells. These increased drilling efficiencies are the result of a number of factors such as Company-supported modifications to our contracted drilling rigs, including 7,500-psi circulating systems, simultaneous operating capabilities, integrated equipment upgrades and other efficiency-related modifications, as well as more experienced personnel on each rig, improved bit designs and starting to drill wells in “batch” mode in some areas.

These increased drilling and completion efficiencies, coupled with service cost reductions of varying amounts, have begun to reduce overall well costs. Recent Wolfcamp wells in the Wolf prospect area have been drilled and completed for approximately $8 million, as compared to $10 to $12 million in 2014 and early 2015. In the Rustler Breaks prospect area, Wolfcamp drilling and completion costs have been reduced to between $6 and $6.5 million per well, and a recent Bone Spring well in this area was drilled and completed for approximately $5 million. These well costs are substantially reduced from those of initial wells drilled in these areas and from well costs originally budgeted in early 2015 for many of these wells. We plan to continue to focus on these operational efficiencies as we move closer to full development of our Delaware Basin assets.

Thus far, we have tested nine different producing horizons in the Bone Spring and Wolfcamp intervals at various locations across our acreage position in the Delaware Basin in Southeast New Mexico and West Texas, including two benches of the Second Bone Spring, the Third Bone Spring, three benches of the Wolfcamp “A”, including the “X” and “Y” sands and the more organic, lower section of the Wolfcamp “A”, two benches of the Wolfcamp “B” and the Wolfcamp “D”.

One of the highlights and technical achievements of our second quarter was the successful drilling and completion of our first three-zone stacked lateral test on a single drilling pad in the Rustler Breaks prospect area in Eddy County, New Mexico. From this single pad location, we successfully stacked three horizontal wells targeting three different horizons including, from shallowest to deepest, the Second Bone Spring, Wolfcamp “A” and Wolfcamp “B”. The Wolfcamp “B” well (Tiger 14-24S-28E RB #224H) had an initial production rate of 1,525 BOE per day, the Wolfcamp “A” well (Tiger 14-24S-28E RB #204H) had an initial production rate of 1,405 BOE per day and the Second Bone Spring well (Tiger 14-24S-28E RB #124H) had an initial production rate of 800 BOE per day. We are encouraged not only by these early results of this important technical advance, but also the potential further savings that we anticipate can be achieved through the repeatability of this “stacked” pay concept at other locations. The wells on this three-well pad were drilled and completed for a total of $19.6 million, but we believe we can further reduce costs for similar three-well pads going forward. For the remainder of 2015 and into 2016, we intend to continue to focus on determining proper well spacing, both horizontally and vertically, in order to establish optimal development plans for each of our prospect areas.

During the second quarter of 2015, we completed and began producing oil and natural gas from four gross (3.3 net) Eagle Ford wells, including three gross (3.0 net) operated wells and one gross (0.3 net) non-operated well. We have now completed our planned operated Eagle Ford drilling and completion operations for 2015. At December 31, 2014, over 95% of our Eagle Ford acreage was either held by production or not burdened by lease expirations until 2016 or later. During the second quarter of 2015, our Eagle Ford production increased to its all-time high of 11,942 BOE per day, consisting of 9,358 barrels of oil per day and 15.5 million cubic feet of natural gas per day. The increased Eagle Ford production in the second quarter of 2015 was primarily attributable to the initial performance of the eight wells completed and placed on production on our Bishop-Brogan lease in Karnes County, Texas late in the first quarter.
We also participated in six gross (0.2 net) non-operated Haynesville shale wells that were completed and placed on production during the second quarter of 2015. Our combined Haynesville and Cotton Valley natural gas production for the

second quarter of 2015, primarily in Northwest Louisiana, was approximately 50.5 million cubic feet per day, up almost three-fold from approximately 18.3 million cubic feet per day in the second quarter of 2014. This increased production was attributable to the ongoing drilling and completion operations in the Haynesville shale by Chesapeake on our Elm Grove properties in Northwest Louisiana during 2014 and 2015.

At June 30, 2015, our estimated total proved oil and natural gas reserves were 87.0 million BOE, including 40.6 million Bbl of oil and 278.6 Bcf of natural gas, with a PV-10 of $942.8 million and a Standardized Measure of $864.1 million. At December 31, 2014, our estimated proved oil and natural gas reserves were 68.7 million BOE, including 24.2 million Bbl of oil and 267.1 Bcf of natural gas, and at June 30, 2014, our estimated proved oil and natural gas reserves were 57.2 million BOE, including 18.6 million Bbl of oil and 231.4 Bcf of natural gas. Our proved oil reserves of 40.6 million Bbl at June 30, 2015 increased 118%, as compared to 18.6 million Bbl at June 30, 2014, and 68%, as compared to 24.2 million Bbl at December 31, 2014. 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 $54.37 per Bbl for the three months ended June 30, 2015, as compared to $97.92 per Bbl for the three months ended June 30, 2014. 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 $2.78 per Mcf for the three months ended June 30, 2015, as compared to $5.69 per Mcf for the three months ended June 30, 2014. This price reflects an uplift as a result of natural gas liquids we produce with our Eagle Ford and Permian Basin natural gas production. 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 realized during the second quarter of 2015.

Estimated Proved Reserves

The following table sets forth our estimated total proved oil and natural gas reserves at June 30, 2015, December 31, 2014 and June 30, 2014. 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 and the Permian Basin, the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers. These reserves estimates were prepared in accordance with the SEC’s rules for oil and natural gas reserves reporting. The estimated reserves shown are for proved reserves only and do not include any unproved reserves classified as probable or possible reserves that might exist for our properties, nor do they include any consideration that would be attributable to interests in unproved and unevaluated acreage beyond those tracts for which proved reserves have been estimated. Proved oil and natural gas reserves are quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our total proved reserves are estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

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	June 30, 2015		December 31, 2014		June 30, 2014	
Estimated Proved Reserves Data: (1) (2)						
Estimated proved reserves:						
Oil (MBbl)(3)	40,594		24,184		18,627	
Natural Gas (Bcf)(4)	278.6		267.1		231.4	
Total (MBOE)(5)	87,027		68,693		57,202	
Estimated proved developed reserves:						
Oil (MBbl)(3)	17,514		14,053		9,917	
Natural Gas (Bcf)(4)	100.2		102.8		60.0	
Total (MBOE)(5)	34,217		31,185		19,917	
Percent developed	39.3	%	45.4	%	34.8	%
Estimated proved undeveloped reserves:						
Oil (MBbl)(3)	23,080		10,131		8,711	
Natural Gas (Bcf)(4)	178.4		164.3		171.4	
Total (MBOE)(5)	52,810		37,508		37,285	
PV-10(6) (in millions)	$942.8		$1,043.4		$826.0	
Standardized Measure(7) (in millions)	$864.1		$913.3		$723.0	

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

(2) Our estimated proved reserves, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic averages of the first-day-of-the-month prices for the period from July 2014 through June 2015 were $68.17 per Bbl for oil and $3.390 per MMBtu for natural gas, for the period from January 2014 through December 2014 were $91.48 per Bbl for oil and $4.350 per MMBtu for natural gas and for the period from July 2013 through June 2014 were $96.75 per Bbl for oil and $4.104 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 June 30, 2015, December 31, 2014 and June 30, 2014 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 June 30, 2015, December 31, 2014 and June 30, 2014 were, in millions, $78.7, $130.1 and $103.0, 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.

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At June 30, 2015, our estimated total proved oil and natural gas reserves were 87.0 million BOE, including 40.6 million Bbl of oil and 278.6 Bcf of natural gas, with a PV-10 of $942.8 million and a Standardized Measure of $864.1 million. At December 31, 2014, our estimated total proved oil and natural gas reserves were 68.7 million BOE, including 24.2 million Bbl of oil and 267.1 Bcf of natural gas, and at June 30, 2014, our estimated total proved oil and natural gas reserves were 57.2 million BOE, including 18.6 million Bbl of oil and 231.4 Bcf of natural gas. Our proved oil reserves of 40.6 million Bbl at June 30, 2015 increased 68%, as compared to 24.2 million Bbl at December 31, 2014, and 118%, as compared to 18.6 million Bbl at June 30, 2014. During the six months ended June 30, 2015, our proved developed reserves increased 10% from 31.2 million BOE at December 31, 2014 to 34.2 million BOE at June 30, 2015. Year-over-year, our proved developed reserves increased 72% from 19.9 million BOE at June 30, 2014. At June 30, 2015, approximately 39% of our total proved reserves were proved developed reserves, 47% of our total proved reserves were oil and 53% 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

Other than as described below, there have been no changes to our critical accounting policies and estimates from those set forth in the Annual Report.

Allocation of Purchase Price in Business Combinations

As part of our business strategy, we periodically pursue the acquisition of oil and natural gas properties. The purchase price in a business combination is allocated to the assets acquired and liabilities assumed based on their fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. The most significant estimates in the allocation typically relate to the value assigned to proved oil and natural gas reserves and unproved and unevaluated properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

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, 2017, i.e., in our first fiscal quarter of 2018. We are currently evaluating the impact, if any, of the adoption of this ASU on our consolidated financial statements.

Interest - Imputation of Interest. In April 2015, the FASB issued ASU 2015-03, Interest - Imputation of Interest (Subtopic 935-30): Simplifying the Presentation of Debt Issuance Costs, which requires companies that have historically presented debt issuance costs as an asset to present those costs as a direct deduction from the carrying amount of the underlying debt liability. The guidance requires retrospective application in financial statements issued for fiscal years and interim periods beginning after December 15, 2015 but early adoption is permitted. The Company adopted this ASU effective June 30, 2015. See "Note 2 - Significant Accounting Policies" to the unaudited condensed consolidated financial statements in this Quarterly Report for a description of the impact of the adoption of this standard on our consolidated financial statements.

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Results of Operations

Revenues

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Operating Data:				
Revenues (in thousands):[1]				
Oil	$68,515	$78,492	$112,251	$142,166
Natural gas	19,333	20,562	38,063	35,820
Total oil and natural gas revenues	87,848	99,054	150,314	177,986
Realized gain (loss) on derivatives	13,780	(2,913)	32,285	(4,756)
Unrealized loss on derivatives	(23,532)	(5,234)	(32,090)	(8,342)
Total revenues	$78,096	$90,907	$150,509	$164,888
Net Production Volumes:[1]				
Oil (MBbl)[2]	1,260	802	2,269	1,463
Natural gas (Bcf)[3]	7.0	3.6	13.6	6.1
Total oil equivalent (MBOE)[4]	2,421	1,403	4,537	2,475
Average daily production (BOE/d)[5]	26,601	15,424	25,066	13,673
Average Sales Prices:				
Oil, with realized derivatives (per Bbl)	$62.72	$94.47	$60.48	$94.67
Oil, without realized derivatives (per Bbl)	$54.37	$97.92	$49.48	$97.20
Natural gas, with realized derivatives (per Mcf)	$3.24	$5.65	$3.34	$5.72
Natural gas, without realized derivatives (per Mcf)	$2.78	$5.69	$2.80	$5.90

(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 June 30, 2015 as Compared to Three Months Ended June 30, 2014

Oil and natural gas revenues. Our oil and natural gas revenues decreased by $11.2 million to $87.8 million, or 11%, for the three months ended June 30, 2015, as compared to $99.1 million for the three months ended June 30, 2014. Our oil revenues decreased by $10.0 million, or 13%, to $68.5 million for the three months ended June 30, 2015, as compared to $78.5 million for the three months ended June 30, 2014. Our oil production increased by 57% to 1.26 million Bbl of oil in the second quarter of 2015, or 13,847 Bbl of oil per day, as compared to 802,000 Bbl of oil in the second quarter of 2014, or 8,809 Bbl of oil per day. This increase in oil production was primarily a result of our ongoing and better-than-expected performance of wells drilled and completed in the Delaware Basin, as well as from newly drilled and completed wells in the Eagle Ford shale in early 2015. The decrease in oil revenues resulted from a lower weighted average oil price realized in the second quarter of 2015 of $54.37 per Bbl as compared to $97.92 per Bbl realized for the second quarter of 2014. This decrease in realized oil price was partially mitigated by the increase in our oil production of 57% in the second quarter of 2015, as compared to the second quarter of 2014. Our natural gas production increased by 93% to 7.0 Bcf for the three months ended June 30, 2015, as compared to 3.6 Bcf for the three months ended June 30, 2014. The increase in natural gas production was primarily attributable to the increased natural gas production resulting from new, non-operated Haynesville shale wells completed and placed on production on our Elm Grove properties in Northwest Louisiana during the latter half of 2014 and into 2015, but also includes increased natural gas production associated with our operations in the Delaware Basin. Our natural gas revenues decreased by $1.2 million, or 6%, to $19.3 million for the three months ended June 30, 2015, as compared to $20.6 million for the three months ended June 30, 2014. The decrease in natural gas revenues resulted from a lower weighted average natural gas price of $2.78 per Mcf realized during the second quarter of 2015, as compared to a weighted average natural gas price of $5.69 per Mcf realized during the second quarter of 2014. This decrease in realized natural gas prices was partially mitigated by the

93% increase in our natural gas production for the three months ended June 30, 2015, as compared to 3.6 Bcf for the three months ended June 30, 2014.

Realized gain (loss) on derivatives. Our realized gain on derivatives was $13.8 million for the three months ended June 30, 2015, as compared to a realized loss of $2.9 million for the three months ended June 30, 2014. For the three months ended June 30, 2015, we realized a net gain of $10.5 million, $2.7 million and $0.5 million attributable to our oil, natural gas and natural gas liquids ("NGL") derivative contracts, respectively. For the three months ended June 30, 2014, we realized a net loss of $2.8 million, a net loss of $0.2 million and a gain of $38,000 attributable to our oil, natural gas and NGL derivative contracts, respectively. The realized gain on our oil and natural gas derivative contracts during the three months ended June 30, 2015 resulted from oil prices that were lower than the floor prices of several of our oil costless collar contracts and natural gas prices that were lower than the floor prices of several of our natural gas costless collar contracts. The realized gain in NGL derivative contracts during the three months ended June 30, 2015 resulted from NGL prices that were lower than the fixed prices of our NGL swap contracts. We realized a gain of approximately $15.48 per Bbl and $0.62 per MMBtu hedged on all of our oil and natural gas derivative contracts, respectively, during the three months ended June 30, 2015, as compared to a loss of $4.36 per Bbl and $0.06 per MMBtu hedged on all of our oil and natural gas derivative contracts, respectively, during the three months ended June 30, 2014. The average floor prices of our oil costless collar contracts were $70.38 per Bbl and $87.73 per Bbl as of June 30, 2015 and June 30, 2014, respectively. The average ceiling prices of our oil costless collar contracts were $87.72 per Bbl and $99.76 per Bbl as of June 30, 2015 and June 30, 2014, respectively. During the second quarter of 2015, our natural gas costless collar contracts had average floor and ceiling prices of $3.26 per MMBtu and $3.94 per MMBtu, respectively, as compared to $3.50 per MMBtu and $4.93 per MMBtu, respectively, during the second quarter of 2014. The realized loss on derivatives on our oil, natural gas and NGL derivatives contracts during the three months ended June 30, 2014 resulted from oil, natural gas and NGL prices that were higher than the ceiling prices of several of our oil costless collar contracts, the ceiling prices of several of our natural gas costless collar contracts and the fixed prices of our NGL swap contracts, respectively. Our total oil and natural gas volumes hedged for the three months ended June 30, 2015 were 7% higher and 32% higher, respectively, than the total oil and natural gas volumes hedged for the same period in 2014.

Unrealized loss on derivatives. Our unrealized loss on derivatives was $23.5 million for the three months ended June 30, 2015, as compared to an unrealized loss of $5.2 million for the three months ended June 30, 2014. During the period from March 31, 2015 to June 30, 2015, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts decreased from $47.0 million to $23.5 million, resulting in an unrealized loss on derivatives of $23.5 million for the three months ended June 30, 2015. The net fair value of our open oil derivative contracts decreased $19.9 million at June 30, 2015, as compared to March 31, 2015, primarily due to the realized revenues from oil derivative contracts settled during the three months ended June 30, 2015 and higher oil futures prices at June 30, 2015. The net fair value of our open natural gas derivative contracts decreased $3.3 million at June 30, 2015, as compared to March 31, 2015, primarily due to the realized revenues from natural gas derivative contracts settled during the three months ended June 30, 2015. Additionally, as our oil and natural gas derivative contracts that were entered into before the decline in commodity prices in late 2014 and early 2015 expired, we have begun to replace them with derivative contracts that have lower floor and ceiling prices, particularly our oil derivative instruments. The net fair value of our open NGL derivative contracts decreased $0.4 million at June 30, 2015, as compared to March 31, 2015, primarily due to the realized revenues from contracts settled during the three months ended June 30, 2015. During the period from March 31, 2014 to June 30, 2014, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts decreased from a net liability of $5.9 million to a net liability of $11.1 million due to increases in futures prices for these commodities, resulting in an unrealized loss on derivatives of $5.2 million for the three months ended June 30, 2014.

Six Months Ended June 30, 2015 as Compared to Six Months Ended June 30, 2014

Oil and natural gas revenues. Our oil and natural gas revenues decreased by approximately $27.7 million to approximately $150.3 million, or a decrease of about 16%, for the six months ended June 30, 2015, as compared to the six months ended June 30, 2014. Our oil revenues decreased by 21% to $112.3 million for the six months ended June 30, 2015, as compared to $142.2 million for the six months ended June 30, 2014. Our oil production increased by 55%

to 2.27 million Bbl of oil in the six months ended June 30, 2015, or about 12,534 Bbl of oil per day, as compared to 1.46 million Bbl of oil, or about 8,080 Bbl of oil per day, in the six months ended June 30, 2014. This increased oil production is primarily attributable to our ongoing and better-than-expected performance of wells drilled and completed in the Delaware Basin, as well as from newly drilled and completed wells in the Eagle Ford shale in early 2015. The decrease in oil revenues resulted from a lower weighted average oil price realized in the six months ended June 30, 2015 of $49.48 per Bbl, as compared to $97.20 per Bbl realized for the six months ended June 30, 2014. Our natural gas production increased by 124% to 13.6 Bcf for the six months ended June 30, 2015, as compared to 6.1 Bcf for the six months ended June 30, 2014. The increase in natural gas production was primarily attributable to the increased natural gas production resulting from new, non-operated Haynesville shale wells completed and placed on production on our Elm Grove properties in Northwest Louisiana during the latter half of 2014 and into 2015, but also includes increased natural gas production associated with our operations in the Delaware Basin. Our natural gas revenues increased by $2.2 million, or 6%, to $38.1 million for the six months ended June 30, 2015, as compared to $35.8 million for the

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six months ended June 30, 2014. The increase in natural gas revenues resulted from the 124% increase in natural gas production for the six months ended June 30, 2015, as compared to the six months ended June 30, 2014, but this production increase was largely offset by a lower weighted average natural gas price of $2.80 per Mcf realized during the six months ended June 30, 2015, as compared to a weighted average natural gas price of $5.90 per Mcf realized during the six months ended June 30, 2014.

Realized gain (loss) on derivatives. We realized a gain on derivatives of approximately $32.3 million for the six months ended June 30, 2015, as compared to a loss of approximately $4.8 million for the six months ended June 30, 2014. For the six months ended June 30, 2015, we realized net gains of approximately $25.0 million, $6.3 million and $1.0 million attributable to our oil, natural gas and NGL derivative contracts, respectively. For the six months ended June 30, 2014, we realized net losses of approximately $3.7 million, $0.8 million and $0.3 million attributable to our oil, natural gas and NGL derivative contracts, respectively. The net gain realized from our derivative contracts for the six months ended June 30, 2015 resulted from oil and natural gas prices below the floor prices on several of our oil and natural gas derivative contracts during the six months ended June 30, 2015, as well as NGL prices below the fixed prices on our NGL derivative contracts during the six months ended June 30, 2015. We realized a gain of approximately $22.69 per Bbl and $0.70 per MMBtu hedged on all of our oil and natural gas derivative contracts, respectively, during the six months ended June 30, 2015, as compared to a loss of $2.93 per Bbl and $0.13 per MMBtu hedged on all of our oil and natural gas derivative contracts, respectively, during the six months ended June 30, 2014. During the six months ended June 30, 2015, our natural gas costless collar contracts had average floor and ceiling prices of $3.50 per MMBtu and $4.31 per MMBtu, respectively, as compared to $3.46 per MMBtu and $4.95 per MMBtu, respectively, for the six months ended June 30, 2014. The average floor prices of our oil costless collar contracts were $75.20 per Bbl and $87.73 per Bbl as of June 30, 2015 and June 30, 2014, respectively. The average ceiling prices of our oil costless collar contracts were $92.31 per Bbl and $99.76 per Bbl as of June 30, 2015 and June 30, 2014, respectively. Our total oil and natural gas volumes hedged for the six months ended June 30, 2015 were 13% lower and 50% higher, respectively, than the total oil and natural gas volumes hedged for the same period in 2014.

Unrealized loss on derivatives. Our unrealized loss on derivatives was approximately $32.1 million for the six months ended June 30, 2015, as compared to an unrealized loss of approximately $8.3 million for the six months ended June 30, 2014. During the period from December 31, 2014 through June 30, 2015, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts decreased from approximately $55.5 million to approximately $23.5 million, resulting in an unrealized loss on derivatives of approximately $32.1 million for the six months ended June 30, 2015. This loss is primarily attributable to realized revenue from oil, natural gas and NGL derivative contracts settled during the six months ended June 30, 2015. Additionally, as our oil and natural gas derivative contracts that were put into place before the decline in commodity prices in late 2014 and early 2015 expired, we have begun to replace them with derivative contracts that have lower floor and ceiling prices, particularly our oil derivative instruments. During the period from December 31, 2013 through June 30, 2014, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts decreased from a net liability of $2.8 million to a net liability of $11.1 million, resulting in an unrealized loss on derivatives of $8.3 million for the six months ended June 30, 2014.

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Expenses

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

(In thousands, except expenses per BOE)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Expenses:				
Production taxes and marketing	$10,258	$9,116	$17,308	$15,122
Lease operating	14,950	11,704	27,996	21,055
Depletion, depreciation and amortization	51,768	31,797	98,239	55,827
Accretion of asset retirement obligations	132	123	244	241
Full-cost ceiling impairment	229,026	—	296,153	—
General and administrative	12,961	8,100	26,372	15,319
Total expenses	$319,095	$60,840	$466,312	$107,564
Operating (loss) income	$(240,999)	$30,067	$(315,803)	$57,324
Other income (expense):				
Net loss on asset sales and inventory impairment	—	—	(97)	—
Interest expense	(5,869)	(1,616)	(7,939)	(3,012)
Interest and other income	502	409	886	447
Total other expense	(5,367)	(1,207)	(7,150)	(2,565)
(Loss) income before income taxes	(246,366)	28,860	(322,953)	54,759
Total income tax (benefit) provision	(89,350)	10,634	(115,740)	20,170
Net income attributable to non-controlling interest in subsidiary	(75)	—	(111)	—
Net (loss) income attributable to Matador Resources Company shareholders	$(157,091)	$18,226	$(207,324)	$34,589
Expenses per BOE:				
Production taxes and marketing	$4.24	$6.50	$3.81	$6.11
Lease operating	$6.18	$8.34	$6.17	$8.51
Depletion, depreciation and amortization	$21.39	$22.66	$21.65	$22.56
General and administrative	$5.35	$5.77	$5.81	$6.19

Three Months Ended June 30, 2015 as Compared to Three Months Ended June 30, 2014

Production taxes and marketing. Our production taxes and marketing expenses increased by $1.1 million to $10.3 million, or 13%, for the three months ended June 30, 2015, as compared to $9.1 million for the three months ended June 30, 2014. On a unit-of-production basis, however, our production taxes and marketing expenses decreased by 35% to $4.24 per BOE for the three months ended June 30, 2015, as compared to $6.50 per BOE for the three months ended June 30, 2014. The increase in production taxes and marketing expenses on an absolute basis was primarily attributable to higher natural gas marketing expenses of $6.1 million for the three months ended June 30, 2015, as compared to natural gas marketing expenses of $4.3 million for the three months ended June 30, 2014, an increase of $1.8 million, due to the 93% increase in natural gas production to 7.0 Bcf during the three months ended June 30, 2015, as compared to 3.6 Bcf of natural gas production for the three months ended June 30, 2014. Our production taxes decreased for the three months ended June 30, 2015 by $0.7 million to $4.2 million, as compared to $4.9 million for the three months ended June 30, 2014, primarily due to the 13% decrease in oil revenues in the second quarter of 2015 as compared to the second quarter of 2014.

Lease operating expenses. Our lease operating expenses increased by $3.2 million to $15.0 million, or an increase of 28%, for the three months ended June 30, 2015, as compared to $11.7 million for the three months ended June 30, 2014. Our lease operating expenses per unit of production decreased 26% to $6.18 per BOE for the three months ended June 30, 2015, as compared to $8.34 per BOE for the three months ended June 30, 2014. Our total oil equivalent production increased 73% to approximately 2.42 million BOE for the three months ended June 30, 2015 from approximately 1.40 million BOE for the three months ended June 30, 2014, including an increase of 57% in oil production to 1.26 million Bbl for the three months ended June 30, 2015, as compared to 802,000 Bbl for the three months ended June 30, 2014, which would typically result in higher lease operating expenses. Oil production was 52% of total production by volume for the three months ended June 30, 2015, as compared to 57% of total production by volume for the three months ended June 30, 2014. The decrease achieved in lease operating expenses on a unit-of-production basis was attributable to several key factors, including (i) no cleanout operations on producing wells as a result of fracturing operations on newly drilled Eagle Ford wells as compared to the same period in 2014, (ii) a decrease in salt water disposal costs on a per barrel basis, particularly in the Delaware Basin, (iii) reduced service costs

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impacting lease operating expenses and (iv) a higher percentage of natural gas production, including a significant increase in Haynesville natural gas production, which typically has lower operating costs due to its lack of associated oil and water production. A joint venture controlled by us drilled, completed and began injecting salt water into a new disposal well in the Wolf prospect area in Loving County, Texas in January 2015, which has reduced water disposal costs in this area; a second water disposal well is planned for this prospect area in the next few months.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $20.0 million to $51.8 million, or an increase of 63%, for the three months ended June 30, 2015, as compared to $31.8 million for the three months ended June 30, 2014. On a unit-of-production basis, our depletion, depreciation and amortization expenses decreased to $21.39 per BOE for the three months ended June 30, 2015, or a decrease of 6%, from $22.66 per BOE for the three months ended June 30, 2014. The increase in the total depletion, depreciation and amortization expenses was attributable to the increase in our oil equivalent production of 73% to 2.42 million BOE from 1.40 million BOE between the respective periods. The decrease in the unit-of-production depletion, depreciation and amortization expenses was attributable to the increase in our estimated total proved oil and natural gas reserves of 52% to 87.0 million BOE at June 30, 2015 from 57.2 million BOE at June 30, 2014. This increase in total proved oil and natural gas reserves was primarily attributable to the continued development of our acreage in the Delaware Basin.

Full-cost ceiling impairment. At June 30, 2015, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $146.3 million. As a result, we recorded an impairment charge of $229.0 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $82.7 million. This full-cost ceiling impairment of $229.0 million is reflected in our operating expenses for the three months ended June 30, 2015. 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 three months ended June 30, 2014.

In determining the full-cost ceiling impairment at June 30, 2015, we estimated the PV-10 of our total proved oil and natural gas reserves using the unweighted arithmetic average of oil and natural gas prices as of the first day of each month for the trailing 12-month period ended June 30, 2015 as required under the guidelines established by the SEC, which were $68.17 per Bbl and $3.39 per MMBtu, respectively. If the unweighted arithmetic average of oil and natural gas prices as of the first day of each month for the trailing 12-month period ended June 30, 2015 had been $56.08 per Bbl and $3.067 per MMBtu, respectively, while all other factors remained constant, our full-cost ceiling would have been reduced by an additional $303 million on a pro forma basis. The aforementioned pro forma prices, as estimated for the twelve month period October 2014 through September 2015, were calculated using a 12-month unweighted arithmetic average of oil and natural gas prices, which included the oil and natural gas prices on the first day of the month for the 11 months ended August 2015, with the price for August 2015 being held constant for September 2015. This pro forma increase in the excess of our net capitalized costs above the full-cost ceiling is attributable to a pro forma reduction of $303 million in the PV-10 of our total proved oil and natural gas reserves, including a pro forma decrease in our estimated total proved reserves to 81.0 million BOE, or a reduction of approximately 7%, from our reported estimated proved reserves of 87.0 million BOE at June 30, 2015, primarily attributable to certain proved undeveloped locations that would no longer be classified as proved undeveloped reserves using the pro forma prices. This calculation of the impact of lower commodity prices on our estimated total proved oil and natural gas reserves and our full-cost ceiling was prepared based on the presumption that all other inputs and assumptions are held constant with the exception of oil and natural gas prices. Therefore, this calculation strictly isolates the impact of commodity prices on our full-cost ceiling and proved reserves. The impact of prices is only one of several variables in the estimation of our proved reserves and full-cost ceiling and other factors could have a significant impact on our future proved reserves and the present value of future cash flows. The other factors that impact future estimates of proved reserves include, but are not limited to, extensions and discoveries, acquisitions of proved reserves, changes in drilling and completion and operating costs, drilling results, revisions due to well performance and other factors, changes in development plans and production, among others. There are numerous uncertainties inherent in the estimation of proved oil and natural gas reserves and accounting for oil and natural gas properties in subsequent periods and this pro forma estimate should not be construed as indicative of our development

plans or future results.
General and administrative. Our general and administrative expenses increased by $4.9 million to $13.0 million, or an increase of 60%, for the three months ended June 30, 2015, as compared to $8.1 million for the three months ended June 30, 2014. The increase in our general and administrative expenses for the three months ended June 30, 2015 was largely attributable to increased payroll expenses associated with additional employees joining the Company between the respective periods to support our increased land, geoscience, drilling, completion, production, accounting and administration functions, including the addition of 29 new employees in Roswell, New Mexico as a result of the HEYCO Merger in late February 2015, the associated expenses for whom were fully reflected in our general and administrative expenses for the first time in the second quarter of 2015. General and administrative expenses also included non-cash stock-based compensation expense of $2.8 million for the three months ended June 30, 2015, as compared to $1.8 million for the three months ended June 30, 2014. The increase in our stock-based compensation expense was primarily attributable to the continued vesting of previously granted awards and new awards granted in 2015. While our general and administrative expenses increased 60% on an absolute basis,

our general and administrative expenses decreased by 7% on a unit-of-production basis to $5.35 per BOE for the three months ended June 30, 2015, as compared to $5.77 per BOE for the three months ended June 30, 2014, as a result of our increased oil equivalent production between the respective periods.

Interest expense. For the three months ended June 30, 2015, we incurred total interest expense of $7.2 million. We capitalized $1.3 million of our interest expense on certain qualifying projects for the three months ended June 30, 2015 and expensed the remaining $5.9 million. For the three months ended June 30, 2014, we incurred total interest expense of $2.3 million. We capitalized $0.7 million of our interest expense on certain qualifying projects for the three months ended June 30, 2014 and expensed the remaining $1.6 million. The increase in total interest expense is attributable to an increase in both the average outstanding borrowings and the coupon interest rate of 6.875% under the Notes as compared to the effective interest rate of approximately 3.7% under our Credit Agreement for the three months ended June 30, 2015. In late April 2015, we used a portion of the net proceeds of the Notes and equity offerings to repay a total of $465.0 million of outstanding borrowings under our Credit Agreement. At June 30, 2015, we had no borrowings outstanding under our Credit Agreement, $0.6 million in letters of credit outstanding and $400.0 million in outstanding Notes. Due to the higher interest rate on the Notes, as compared to the interest rate on borrowings under our Credit Agreement, we expect to incur increased interest expense in future periods.

Total income tax (benefit) provision. We had an effective tax rate of 36.3% for the three months ended June 30, 2015. The total income tax benefit for the three months ended June 30, 2015 differed from amounts computed by applying the U.S. federal statutory tax rate to the pre-tax loss due primarily to state tax apportionments and nondeductible expenses. The total income tax benefit of $89.4 million for the three months ended June 30, 2015 included $82.7 million of deferred income tax benefit resulting from the full-cost ceiling impairment. At June 30, 2014, based on our projections for the remainder of 2014, we anticipated incurring a small alternative minimum tax liability for the year ending December 31, 2014, the proportionate share of which was recorded as the current income tax provision of $1.5 million for the three months ended June 30, 2014. Our effective tax rate for the three months ended June 30, 2014 was 36.8%. Total income tax expense for the three months ended June 30, 2014 differed from amounts computed by applying the U.S. federal statutory tax rate to pre-tax income due primarily to the impact of permanent differences between book and taxable income.

Six Months Ended June 30, 2015 as Compared to Six Months Ended June 30, 2014

Production taxes and marketing. Our production taxes and marketing expenses increased by approximately $2.2 million to approximately $17.3 million, or an increase of approximately 14%, for the six months ended June 30, 2015, as compared to $15.1 million for the six months ended June 30, 2014, 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 decreased by 38% to $3.81 per BOE for the six months ended June 30, 2015, as compared to $6.11 per BOE for the six months ended June 30, 2014. The increase in our production taxes and marketing expenses on an absolute basis was primarily attributable to higher natural gas marketing expenses of $10.5 million for the six months ended June 30, 2015, as compared to natural gas marketing expenses of $6.3 million for the six months ended June 30, 2014, due to the 124% increase in natural gas production to 13.6 Bcf during the six months ended June 30, 2015, as compared to 6.1 Bcf of natural gas production for the six months ended June 30, 2014. Our production taxes, however, decreased for the six months ended June 30, 2015 by $1.9 million to $6.8 million, as compared to $8.8 million for the six months ended June 30, 2014, primarily due to the 21% decrease in oil revenues during the six months ended June 30, 2015 as compared to the six months ended June 30, 2014.

Lease operating expenses. Our lease operating expenses increased by approximately $6.9 million, or an increase of 33%, to $28.0 million for the six months ended June 30, 2015, as compared to $21.1 million for the six months ended June 30, 2014. Our lease operating expenses per unit of production decreased 27% to $6.17 per BOE for the six months ended June 30, 2015, as compared to $8.51 per BOE for the six months ended June 30, 2014. Between these respective periods, our total oil equivalent production increased about 83% to 4.54 million BOE from 2.48 million BOE, including an increase of 55% in oil production to 2.27 million Bbl of oil from 1.46 million Bbl of oil, which would typically result in higher lease operating expenses. Oil production was 50% of total production by volume for the six months ended June 30, 2015, as compared to 59% of total production by volume for the six months ended June 30, 2014. The decrease achieved in lease operating expenses on a per unit basis was attributable to several key factors, including (i) fewer cleanout operations on producing wells as a result of fracturing operations on newly drilled Eagle Ford wells as compared to the same period in 2014, (ii) a decrease in salt water disposal costs on a per barrel basis, particularly in the Delaware Basin, (iii) reduced service costs impacting lease operating expenses and (iv) a higher percentage of natural gas production, including a significant increase in Haynesville natural gas production, which typically has lower operating costs due to its lack of associated oil and water production. A joint venture controlled by us drilled, completed and began injecting salt water into a new disposal well in the Wolf prospect area in Loving County, Texas in January 2015, which has reduced water disposal costs in this area; a second salt water disposal well is planned for this prospect area in the next few months.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $42.4 million to $98.2 million, or an increase of 76%, for the six months ended June 30, 2015, as compared to $55.8 million for the six months ended June 30, 2014. On a unit-of-production basis, our depletion, depreciation and amortization expenses decreased to $21.65 per BOE for the six months ended June 30, 2015, or a decrease of about 4%, from $22.56 per BOE for the six months ended June 30, 2014. The increase in the total depletion, depreciation and amortization expenses was attributable to the increase in our oil and natural gas production by 83% to 4.54 million BOE from 2.48 million BOE between the respective periods. The decrease in the per-unit-of-production depletion, depreciation and amortization expenses resulted from significantly higher estimated total proved reserves of 87.0 million BOE, or a 52% increase, at June 30, 2015, as compared to estimated total proved reserves of 57.2 million BOE at June 30, 2014. This increase in total proved oil and natural gas reserves was primarily attributable to the continued development of our acreage in the Delaware Basin.

Full-cost ceiling impairment. At June 30, 2015, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $146.3 million. As a result, we recorded an impairment charge of $229.0 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $82.7 million. At March 31, 2015, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $42.8 million. As a result, we recorded an impairment charge of $67.1 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $24.3 million. These full-cost ceiling impairments of $296.1 million are reflected in our operating expenses for the six months ended June 30, 2015. 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 six months ended June 30, 2014.

General and administrative. Our general and administrative expenses increased by $11.1 million to $26.4 million, or an increase of approximately 72%, for the six months ended June 30, 2015, as compared to $15.3 million for the six months ended June 30, 2014. The increase in our general and administrative expenses for the six months ended June 30, 2015 was primarily attributable to increased payroll expenses associated with additional employees joining the Company between the respective periods to support our increased land, geoscience, drilling, completion, production, accounting and administration functions, including the addition of 29 new employees in Roswell, New Mexico as a result of the HEYCO Merger in late February 2015, the associated expenses for whom were partially reflected in our general and administrative expenses for the first time in the six months ended June 30, 2015. General and administrative expenses also included an increase in non-cash stock-based compensation costs of $1.5 million to $5.1 million for the six months ended June 30, 2015, as compared to $3.6 million for the six months ended June 30, 2014, as well as $2.5 million in transaction costs associated with the HEYCO Merger. Because the HEYCO Merger was a business combination and not solely an asset purchase, the transaction costs were required to be expensed. The increase in our stock-based compensation expense was primarily attributable to the continued vesting of previously granted awards and new awards granted in 2015. While our general and administrative expenses increased 72% on an absolute basis, our general and administrative expenses decreased by 6% on a unit-of-production basis to $5.81 per BOE for the six months ended June 30, 2015, as compared to $6.19 per BOE for the six months ended June 30, 2014, as a result of our increased oil equivalent production between the respective periods.

Interest expense. For the six months ended June 30, 2015, we incurred total interest expense of approximately $10.2 million. We capitalized approximately $2.3 million of our interest expense on certain qualifying projects for the six months ended June 30, 2015 and expensed the remaining $7.9 million. For the six months ended June 30, 2014, we incurred total interest expense of approximately $4.4 million. We capitalized approximately $1.4 million of our interest expense on certain qualifying projects for the six months ended June 30, 2014 and expensed the remaining $3.0 million. The increase in total interest expense was attributable to an increase in both the average outstanding borrowings and the coupon interest rate of 6.875% under the Notes as compared to the effective interest rate of approximately 2.9% under our Credit Agreement for the six months ended June 30, 2015. In late April 2015, we used a portion of the net proceeds of the Notes and equity offerings to repay a total of $465.0 million of outstanding borrowings under our Credit Agreement. At June 30, 2015, we had no outstanding borrowings under our Credit Agreement, $0.6 million in letters of credit outstanding and $400.0 million in outstanding Notes. Due to the higher interest rate on the Notes as compared to the interest rate on the Credit Agreement, we expect to incur increased interest expense in future periods.

Total income tax (benefit) provision. Our effective tax rate for the six months ended June 30, 2015 was 35.8%. The total income tax expense for the six months ended June 30, 2015 differed from amounts computed by applying the U.S. federal statutory tax rates to the pre-tax loss due primarily to state tax apportionments and nondeductible expenses. The total income tax benefit of approximately $115.7 million for the six months ended June 30, 2015 also included approximately $107.0 million of deferred income tax benefit resulting from the full-cost ceiling impairment. Our effective tax rate for the six months ended June 30, 2014 was 36.8%. Total income tax expense for the six months ended June 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.

Liquidity and Capital Resources

Our primary use of capital has been, and we expect will continue for the foreseeable future to be, for the acquisition, exploration and development of oil and natural gas properties and for related midstream investments. 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.

During the three months ended June 30, 2015, the borrowings under our Credit Agreement bore interest at an effective interest rate of 3.7% per annum. During the three months ended June 30, 2015, using a portion of the net proceeds from the Notes offering and public offering of common stock discussed herein, we repaid all, or a total of $465.0 million, of the outstanding borrowings under our Credit Agreement. At June 30, 2015, we had cash totaling $53.6 million and the borrowing base under our Credit Agreement was $375.0 million. At both June 30, 2015 and August 6, 2015, we had no borrowings outstanding and $0.6 million in outstanding letters of credit pursuant to our Credit Agreement and $400.0 million of outstanding Notes.

Our original 2015 capital expenditure budget was $350.0 million (excluding capital expenditures associated with the HEYCO Merger). On August 4, 2015, we increased our 2015 capital expenditure budget to $425.0 million (excluding capital expenditures associated with the HEYCO Merger). Our increased 2015 capital expenditure budget includes approximately $307.0 million for drilling and completing oil and natural gas exploration and development wells, with the remainder allocated to lease acquisitions, seismic data, midstream initiatives, pipelines and other infrastructure. We were operating five drilling rigs, two rigs in the Eagle Ford and three rigs in the Permian (Delaware) Basin, at the beginning of 2015, but reduced our operated drilling rigs to two by the end of the first quarter of 2015, with both operating in the Permian Basin. In late July 2015, we took delivery of a third drilling rig which has begun drilling in our Jackson Trust prospect area in northeast Loving County, Texas testing the Second Bone Spring and shallower targets. Following the conclusion of those operations, the rig is scheduled to start drilling in our Ranger and Arrowhead prospect areas (including acreage acquired in the HEYCO Merger) in northern Eddy and Lea Counties, New Mexico to further delineate the Bone Spring and Wolfcamp potential in those areas. We are currently operating three drilling rigs in the Delaware Basin, two in Loving County, Texas and one in Eddy County, New Mexico. We have completed our planned operated drilling and completion activities in the Eagle Ford shale for 2015. We expect to continue to participate in several non-operated Haynesville shale wells drilled by Chesapeake and other operating partners during the remainder of 2015.

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. A significant portion of our anticipated cash flows from operations for the remainder of 2015 is expected to come from producing wells and development activities on currently proved properties in the Eagle Ford shale in South Texas, the Wolfcamp and Bone Spring plays in the Permian Basin and the Haynesville shale in Louisiana. Our existing wells may not produce at the levels we are forecasting and our exploration and development activities in these areas 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 2015 and the hedges we currently have in place. 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. At August 4, 2015, we had approximately 75% of our anticipated oil production and approximately 65% of our anticipated natural gas production hedged for the remainder of 2015.

Expenditures for the acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. As of August 4, 2015, we anticipate investing approximately $425.0 million in capital (excluding capital expenditures associated with the HEYCO Merger) for acquisition, exploration and development activities in 2015 as follows:

	Amount (in millions)

Exploration, development drilling and completion costs	$ 307.0
Midstream activities	48.0
Pipeline and infrastructure expenditures	30.0
Leasehold acquisition and 2-D and 3-D seismic data	40.0
Total	$ 425.0

While we have budgeted $425.0 million in capital expenditures (excluding capital expenditures associated with the HEYCO Merger) for 2015, 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 2015. When oil or natural gas prices decline, as oil and natural gas prices have done since mid-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.

Excluding any possible significant acquisitions, we expect to fund our remaining 2015 capital expenditure budget through a combination of cash on hand, operating cash flows, borrowings under our Credit Agreement, potential joint ventures and the potential sale of assets or acreage. 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.

Our unaudited cash flows for the six months ended June 30, 2015 and 2014 are presented below:

	Six Months Ended June 30,	
(In thousands)	2015	2014
Net cash provided by operating activities	$113,390	$113,475
Net cash used in investing activities	(293,996)	(236,219)
Net cash provided by financing activities	225,822	131,092
Net change in cash	$45,216	$8,348
Adjusted EBITDA[1]	$116,829	$125,810

(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 decreased by $0.1 million to $113.4 million for the six months ended June 30, 2015, as compared to net cash provided by operating activities of $113.5 million for the six months ended June 30, 2014. Excluding changes in operating assets and liabilities, net cash provided by operating activities decreased by $11.0 million to $109.0 million for the six months ended June 30, 2015 from $120.0 million for the six months ended June 30, 2014. This decrease is primarily attributable to the 16% decrease in our oil and natural gas revenues between the respective periods. Changes in our operating assets and liabilities between June 30, 2014 and June 30, 2015 resulted in a net increase of $10.9 million in net cash provided by operating activities for the six months ended June 30, 2015.

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, the actions of OPEC, 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 $57.8 million to $294.0 million for the six months ended June 30, 2015 from $236.2 million for the six months ended June 30, 2014. This increase in net cash used in investing activities is primarily attributable to the increase in cash used for our midstream investments, including construction of a salt water disposal facility and a natural gas processing plant in Loving County, Texas, for the six months ended June 30, 2015, as compared to the six months ended June 30, 2014, but also includes capital expenditures associated with the HEYCO Merger. Cash used for oil and natural gas properties capital expenditures for the six months ended June 30, 2015 was primarily attributable to our operated drilling and completion activities in the Permian Basin and the Eagle Ford shale play. A small portion of our capital expenditures for the six months ended June 30, 2015 was directed to our participation in non-operated wells, primarily in the Haynesville shale.

Cash Flows Provided by Financing Activities

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Net cash provided by financing activities increased by $94.7 million to $225.8 million for the six months ended June 30, 2015 from $131.1 million for the six months ended June 30, 2014. The net cash provided by financing activities for the six months ended June 30, 2015 was attributable to the net proceeds from our Notes offering of approximately $391 million, the net proceeds from our equity offering of $187.5 million and proceeds from borrowings under the Credit Agreement of $125.0 million. These net proceeds were partially offset by the repayment of the borrowings outstanding under our Credit Agreement and Assumed Indebtedness of $477.0 million and the taxes paid related to net share settlement of stock-based compensation of $1.6 million. The net cash provided by financing activities for the six months ended June 30, 2014 was primarily attributable to the total proceeds of our May 2014 equity offering of $181.9 and incremental borrowings under our Credit Agreement of $130.0 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.

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.

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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 June 30,		Six Months Ended June 30,	
(In thousands)	2015	2014	2015	2014
Unaudited Adjusted EBITDA Reconciliation to Net (Loss) Income:				
Net (loss) income attributable to Matador Resources Company shareholders	$(157,091)	$18,226	$(207,324)	$34,589
Interest expense	5,869	1,616	7,939	3,012
Total income tax (benefit) provision	(89,350)	10,634	(115,740)	20,170
Depletion, depreciation and amortization	51,768	31,797	98,239	55,827
Accretion of asset retirement obligations	132	123	244	241
Full-cost ceiling impairment	229,026	—	296,153	—
Unrealized loss on derivatives	23,532	5,234	32,090	8,342
Stock-based compensation expense	2,794	1,834	5,131	3,629
Net loss on asset sales and inventory impairment	—	—	97	—
Adjusted EBITDA	$66,680	$69,464	$116,829	$125,810

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	2015	2014	2015	2014
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:				
Net cash provided by operating activities	$20,043	$81,530	$113,390	$113,475
Net change in operating assets and liabilities	40,843	(15,221)	(4,389)	6,509
Interest expense	5,869	1,616	7,939	3,012
Current income tax provision	—	1,539	—	2,814
Net income attributable to non-controlling interest in subsidiary	(75)	—	(111)	—
Adjusted EBITDA	$66,680	$69,464	$116,829	$125,810

Our Adjusted EBITDA decreased by $2.8 million to $66.7 million, or a decrease of 4%, for the three months ended June 30, 2015, as compared to $69.5 million for the three months ended June 30, 2014. Our Adjusted EBITDA decreased by $9.0 million to $116.8 million, or a decrease of 7%, for the six months ended June 30, 2015, as compared to $125.8 million for the six months ended June 30, 2014. This decrease in our Adjusted EBITDA is primarily attributable to the decrease in our oil and natural gas revenues resulting from lower commodity prices for the three and six months ended June 30, 2015 as compared to the three and six months ended June 30, 2014.

See “Note 6 - Debt” to the unaudited condensed consolidated financial statements in this Quarterly Report for a summary of our debt.

Off-Balance Sheet Arrangements

From time-to-time, we enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of June 30, 2015, the material off-balance sheet arrangements and transactions that we have entered into include (i) operating lease agreements, (ii) non-operated drilling commitments, (iii) termination obligations under drilling rig contracts, (iv) firm transportation and fractionation commitments, (v) agreements to construct facilities and (vi) contractual obligations for which the ultimate settlement amounts are not fixed and determinable, such as derivative contracts that are sensitive to future changes in commodity prices or interest rates, gathering, treating, fractionation and transportation commitments on uncertain volumes of future throughput, open delivery commitments and indemnification obligations following certain divestitures. Other than the off-balance sheet arrangements described above, we have no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources. See “Obligations and Commitments” below and “Note 11 – Commitments and Contingencies” to the unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding our off-balance sheet arrangements. Such information is incorporated herein by reference.

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Obligations and Commitments

We had the following material contractual obligations and commitments at June 30, 2015:

	Payments Due by Period				
(In thousands)	Total	Less Than 1 Year	1 - 3 Years	3 - 5 Years	More Than 5 Years
Contractual Obligations:					
Revolving credit borrowings, including letters of credit(1)	$571	$571	$—	$—	$—
Senior unsecured notes	400,000	—	—	—	400,000
Office leases	27,509	1,271	4,868	5,050	16,320
Non-operated drilling commitments(2)	22,762	22,762	—	—	—
Drilling rig contracts(3)	43,792	23,514	20,278	—	—
Asset retirement obligations	13,380	275	1,189	2,727	9,189
Gas processing and transportation agreement(4)	4,504	2,404	2,100	—	—
Gas plant engineering, procurement, construction and installation agreement (5)	3,000	3,000	—	—	—
Total contractual cash obligations	$515,518	$53,797	$28,435	$7,777	$425,509

(1) At June 30, 2015, we had no borrowings outstanding under our Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. The Credit Agreement is scheduled to mature in December 2016.

(2) At June 30, 2015, 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 June 30, 2015. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of $22.8 million at June 30, 2015, 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 were until recently 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 rig or if the drilling contractor were unable to secure work for the contracted drilling rig 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 $43.8 million at June 30, 2015.

(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 $4.5 million at June 30, 2015.

(5) We entered into an agreement with a third party for the engineering, procurement, construction and installation of a natural gas processing plant in Loving County, Texas in 2014. This plant is expected to process a portion of our natural gas produced from certain of our wells in the Permian Basin, as well as third-party natural gas. The plant is scheduled to be completed and placed in service in the third quarter of 2015.

General Outlook and Trends

For the six months ended June 30, 2015, oil prices ranged from a low of approximately $43.46 per Bbl in mid-March to a high of approximately $61.43 per Bbl in early June, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. We realized an average oil price of $49.48 per Bbl ($60.48 per Bbl including realized gains from oil derivatives) for our oil production for the six months ended June 30, 2015, as compared to $97.20 per Bbl ($94.67 per Bbl including realized losses from oil derivatives) for the six months ended June 30, 2014. Subsequent to June 30, 2015, oil prices have decreased and, at August 6, 2015, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date closed at $44.66 per Bbl, as compared to $96.92 per Bbl at August 6, 2014.

For the six months ended June 30, 2015, natural gas prices ranged from a high of $3.23 per MMBtu in mid-January to a low of $2.49 per MMBtu in late April, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. We realized a weighted average natural gas price of $2.80 per Mcf ($3.34 per Mcf including aggregate realized gains from natural gas and NGL derivatives) for our natural gas production for the six months ended June 30, 2015, as compared to $5.90 per Mcf ($5.72 per Mcf including aggregate realized losses from natural gas and NGL derivatives) for the six months ended June 30, 2014. 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 2015 low in late

April, natural gas prices have increased somewhat, and at August 6, 2015, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date closed at $2.81 per MMBtu, as compared to $3.93 per MMBtu at August 6, 2014.

In response to the sharp decrease in oil and natural gas prices experienced in late 2014 and early 2015, we reduced our original 2015 estimated capital expenditure budget to $350.0 million (excluding capital expenditures associated with the HEYCO Merger), as compared to actual capital expenditures of $610.4 million for the year ended December 31, 2014. We increased our 2015 capital expenditure budget to $425.0 million (excluding capital expenditures associated with the HEYCO Merger) in August 2015. This increased 2015 capital expenditure budget includes the addition of a third drilling rig in the Delaware Basin in late July 2015, as well as capital for our participation in additional non-operated wells, additional acquisitions of oil and natural gas leases and additional midstream investments. We are currently running three drilling rigs in the Delaware Basin, two in Loving County, Texas and one in Eddy County, New Mexico. We have completed our planned operated drilling and completion activities in the Eagle Ford shale for 2015, as over 95% of our Eagle Ford acreage was held by production or not burdened by lease expirations until 2016 at December 31, 2014. We expect to continue to participate in several non-operated Haynesville shale wells drilled by Chesapeake and other operating partners during the remainder of 2015.

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. This, in turn, may affect the liquidity that can be accessed through the borrowing base under our Credit Agreement and through the capital markets. Additionally, as our oil and natural gas derivative financial instruments that were entered into prior to the decline in commodity prices in late 2014 and early 2015 expire, we have begun to replace them with derivative instruments with lower floor and ceiling prices, particularly our oil derivative instruments. As a result, we expect our realized gains from derivatives to be less in 2016, as compared to comparable periods in 2015, especially from our oil derivative contracts.

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, 2014, 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.

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.

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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 June 30, 2015, RBC, Comerica Bank, The Bank of Nova Scotia and BMO Harris Financing, Inc. (Bank of Montreal) (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 9 - Derivative Financial Instruments” to the unaudited condensed consolidated financial statements in this Quarterly Report for a summary of our open derivative financial instruments at June 30, 2015. 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 June 30, 2015 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 June 30, 2015, 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.

SIGNATURES

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

		MATADOR RESOURCES COMPANY
Date: August 7, 2015	By:	/s/ Joseph Wm. Foran Joseph Wm. Foran Chairman and Chief Executive Officer
Date: August 7, 2015	By:	/s/ David E. Lancaster David E. Lancaster Executive Vice President and Chief Financial Officer

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EXHIBIT INDEX

Exhibit Number	Description
10.1	Purchase Agreement, dated as of April 9, 2015, by and among Matador Resources Company, the subsidiary guarantors party thereto and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on April 14, 2015).
10.2	Sixth Amendment to Third Amended and Restated Credit Agreement, dated as of April 14, 2015, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on April 14, 2015).
10.3	Amended and Restated Independent Contractor Agreement by and among Matador Resources Company, David F. Nicklin and David F. Nicklin International Consulting, Inc., effective as of April 1, 2015 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on June 11, 2015).
10.4	Amended and Restated 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on June 11, 2015).
23.1	Consent of Netherland, Sewell & Associates, Inc. (filed herewith).
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99.1	Audit report of Netherland, Sewell & Associates, Inc. (filed herewith).
101	The following financial information from Matador Resources Company’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2015 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).