Matador Resources Co
Form 10-Q
May 11, 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 March 31, 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 May 6, 2015, there were 85,370,330 shares of the registrant’s common stock, par value $0.01 per share, outstanding.

Table of Contents

MATADOR RESOURCES COMPANY
FORM 10-Q
FOR THE QUARTER ENDED MARCH 31, 2015
INDEX

	Page
PART I — FINANCIAL INFORMATION	3
Item 1. Financial Statements - Unaudited	3
Condensed Consolidated Balance Sheets at March 31, 2015 and December 31, 2014	3
Condensed Consolidated Statements of Operations for the Three Months Ended March 31, 2015 and 2014	4
Condensed Consolidated Statement of Changes in Shareholders' Equity for the Three Months Ended March 31, 2015	5
Condensed Consolidated Statements of Cash Flows for the Three Months Ended March 31, 2015 and 2014	6
Notes to Condensed Consolidated Financial Statements	7
Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations	24
Item 3. Quantitative and Qualitative Disclosures About Market Risk	43
Item 4. Controls and Procedures	44
PART II — OTHER INFORMATION	45
Item 1. Legal Proceedings	45
Item 1A. Risk Factors	45
Item 6. Exhibits	45
SIGNATURES	46

Table of Contents

Part I – FINANCIAL INFORMATION
Item 1. Financial Statements
Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED BALANCE SHEETS - UNAUDITED
(In thousands, except par value and share data)

	March 31, 2015	December 31, 2014
ASSETS		
Current assets		
Cash	$6,061	$ 8,407
Restricted cash	991	609
Accounts receivable		
Oil and natural gas revenues	26,349	28,976
Joint interest billings	12,924	6,925
Other	7,114	9,091
Derivative instruments	47,011	55,549
Lease and well equipment inventory	1,718	1,212
Prepaid expenses	3,025	2,554
Total current assets	105,193	113,323
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	1,785,208	1,617,913
Unproved and unevaluated	449,042	264,419
Other property and equipment	64,610	43,472
Less accumulated depletion, depreciation and amortization	(717,330)	(603,732)
Net property and equipment	1,581,530	1,322,072
Other assets		
Other assets	703	896
Total other assets	703	896
Total assets	$1,687,426	$ 1,436,291
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$61,476	$ 17,526
Accrued liabilities	128,845	109,502
Royalties payable	11,932	14,461
Note payable	11,982	—
Advances from joint interest owners	1,378	—
Deferred income taxes	16,462	19,751
Income taxes payable	—	444
Other current liabilities	123	103
Total current liabilities	232,198	161,787
Long-term liabilities		
Borrowings under Credit Agreement	410,000	340,000
Asset retirement obligations	13,275	11,640
Derivative instruments	19	—
Deferred income taxes	106,649	53,783
Other long-term liabilities	2,451	2,540
Total long-term liabilities	532,394	407,963
Commitments and contingencies (Note 11)		

Shareholders’ equity		
Preferred stock - Series A, $0.01 par value, 2,000,000 shares authorized; 150,000 and zero shares issued and outstanding, respectively	1	—
Common stock - $0.01 par value, 80,000,000 shares authorized; 76,844,899 and 73,373,744 shares issued; and 76,780,402 and 73,342,777 shares outstanding, respectively	769	734
Additional paid-in capital	830,824	724,819
Retained earnings	90,621	140,855
Treasury stock, at cost, 64,497 and 30,967 shares, respectively	—	—
Total Matador Resources Company shareholders’ equity	922,215	866,408
Non-controlling interest in subsidiary	619	133
Total shareholders' equity	922,834	866,541
Total liabilities and shareholders’ equity	$1,687,426	$ 1,436,291

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

3

Table of Contents

Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS - UNAUDITED
(In thousands, except per share data)

	Three Months Ended March 31, 2015	2014
Revenues		
Oil and natural gas revenues	$62,465	$78,931
Realized gain (loss) on derivatives	18,504	(1,843)
Unrealized loss on derivatives	(8,557)	(3,108)
Total revenues	72,412	73,980
Expenses		
Production taxes and marketing	7,049	6,006
Lease operating	13,046	9,351
Depletion, depreciation and amortization	46,470	24,030
Accretion of asset retirement obligations	112	117
Full-cost ceiling impairment	67,127	—
General and administrative	13,413	7,219
Total expenses	147,217	46,723
Operating (loss) income	(74,805)	27,257
Other income (expense)		
Net loss on asset sales and inventory impairment	(97)	—
Interest expense	(2,070)	(1,396)
Interest and other income	384	38
Total other expense	(1,783)	(1,358)
(Loss) income before income taxes	(76,588)	25,899
Income tax (benefit) provision		
Current	—	1,275
Deferred	(26,390)	8,261
Total income tax (benefit) provision	(26,390)	9,536
Net (loss) income	(50,198)	16,363
Net income attributable to non-controlling interest in subsidiary	(36)	—
Net (loss) income attributable to Matador Resources Company shareholders	$(50,234)	$16,363
Earnings (loss) per common share		
Basic	$(0.68)	$0.25
Diluted	$(0.68)	$0.25
Weighted average common shares outstanding		
Basic	73,819	65,684
Diluted	73,819	66,229

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

Table of Contents

Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS’ EQUITY - UNAUDITED
(In thousands)
For the Three Months Ended March 31, 2015

	Common Stock Shares	Amount	Preferred Stock Shares	Amount	Additional paid-in capital	Retained earnings	Treasury Stock Shares	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	3,300	33	—	—	71,445	—	—	—	71,478	—	71,478
Issuance of preferred stock	—	—	150	1	32,489	—	—	—	32,490	—	32,490
Common stock issued to Board members and advisors	6	—	—	—	4	—	—	—	4	—	4
Stock options expense related to equity-based awards	—	—	—	—	1,019	—	—	—	1,019	—	1,019
Stock options exercised	3	—	—	—	—	—	—	—	—	—	—
Restricted stock issued	163	2	—	—	(2)	—	—	—	—	—	—
Restricted stock forfeited	—	—	—	—	—	—	33	—	—	—	—
Restricted stock and restricted stock units expense	—	—	—	—	1,050	—	—	—	1,050	—	1,050
Capital contribution to less than wholly owned subsidiary	—	—	—	—	—	—	—	—	—	450	450
Current period net (loss) income	—	—	—	—	—	(50,234)	—	—	(50,234)	36	(50,198)
Balance at March 31, 2015	76,846	$ 769	150	$ 1	$ 830,824	$ 90,621	64	$ —	$ 922,215	$ 619	$ 922,834

The accompanying notes are an integral part of these financial statements.
5

Table of Contents

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

	Three Months Ended March 31,	
	2015	2014
Operating activities		
Net (loss) income	$(50,198)	$16,363
Adjustments to reconcile net (loss) income to net cash provided by operating activities		
Unrealized loss on derivatives	8,557	3,108
Depletion, depreciation and amortization	46,470	24,030
Accretion of asset retirement obligations	112	117
Full-cost ceiling impairment	67,127	—
Stock-based compensation expense	2,337	1,795
Deferred income tax (benefit) provision	(26,390)	8,261
Net loss on asset sales and inventory impairment	97	—
Changes in operating assets and liabilities		
Accounts receivable	2,140	(6,941)
Lease and well equipment inventory	(112)	(31)
Prepaid expenses	(364)	(424)
Other assets	193	(466)
Accounts payable, accrued liabilities and other current liabilities	45,703	(16,540)
Royalties payable	(2,907)	1,597
Advances from joint interest owners	1,378	—
Income taxes payable	(444)	1,275
Other long-term liabilities	(353)	(199)
Net cash provided by operating activities	93,346	31,945
Investing activities		
Oil and natural gas properties capital expenditures	(127,440)	(92,891)
Expenditures for other property and equipment	(14,241)	(1,007)
Business combination, net of cash acquired	(24,028)	—
Restricted cash in less than wholly-owned subsidiary	(383)	—
Net cash used in investing activities	(166,092)	(93,898)
Financing activities		
Borrowings under Credit Agreement	70,000	70,000
Proceeds from stock options exercised	—	6
Capital commitment from non-controlling interest in subsidiary	450	—
Taxes paid related to net share settlement of stock-based compensation	(50)	—
Net cash provided by financing activities	70,400	70,006
Increase (decrease) in cash	(2,346)	8,053
Cash at beginning of period	8,407	6,287
Cash at end of period	$6,061	$14,340

Supplemental disclosures of cash flow information (Note 12)

The accompanying notes are an integral part of these financial statements.
6

Table of Contents

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 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 wholly-owned and majority-owned 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 proportionately consolidates certain subsidiaries that are less-than-wholly-owned and the net income and equity to the non-controlling interest in these subsidiaries have been reported separately as required by Accounting Standards Codification ("ASC") 810. All intercompany accounts and transactions have been eliminated in consolidation.
In management's opinion, these interim unaudited condensed consolidated financial statements include all adjustments of a normal recurring nature necessary for a fair presentation of the Company's consolidated financial position as of March 31, 2015, consolidated results of operations for the three months ended March 31, 2015 and 2014, consolidated changes in shareholders' equity for the three months ended March 31, 2015 and consolidated cash flows for the three months ended March 31, 2015 and 2014. Amounts as of December 31, 2014 are derived from the audited consolidated financial statements in the Annual Report.

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

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

Reclassifications

Certain reclassifications have been made to the prior years' financial statements to conform to the current year presentation. These reclassifications had no effect on previously reported results of operations, cash flows or retained earnings.

Restricted Cash

Restricted cash represents the cash held by our less-than-wholly-owned subsidiary. By contractual agreement, the cash in this account is not to be commingled with other Company cash and is to be used only to fund the capital expenditures and operations of this less-than-wholly-owned subsidiary, which disposes of limited quantities of Company and third-party salt water.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

Property and Equipment

The Company uses the full-cost method of accounting for its investments in oil and natural gas properties. Under this method of accounting, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing the Company's activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects and 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 $1.6 million and $0.9 million of its general and administrative costs for the three months ended March 31, 2015 and 2014, respectively. The Company capitalized approximately $1.0 million and $0.7 million of its interest expense for the three months ended March 31, 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 April 2014 through March 2015, these average oil and natural gas prices were $79.21 per barrel ("Bbl") and $3.882 per million British thermal units ("MMBtu"), respectively. For the period from April 2013 through March 2014, these average oil and natural gas prices were $94.92 per Bbl and $3.989 per MMBtu, respectively. In estimating the present value of after-tax future net cash flows from proved oil and natural gas reserves, the average oil prices were adjusted by property for quality, transportation and marketing fees and regional price differentials, and the average natural gas prices were adjusted by property for energy content, transportation and marketing fees and regional price differentials. At March 31, 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, for the oil and natural gas reserves estimates at March 31, 2015, audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

Using the average commodity prices, as adjusted, to determine the Company's estimated proved oil and natural gas reserves at March 31, 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 three months ended March 31, 2015. Using the average commodity prices, as adjusted, to determine the Company’s estimated proved oil and natural gas reserves at March 31, 2014, the Company’s net capitalized costs less related deferred income taxes did not exceed the full-cost

Table of Contents

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

ceiling. As a result, the Company recorded no impairment to its net capitalized costs for the three months ended March 31, 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 months ended March 31, 2015 and 2014 (in thousands).

	Three Months Ended March 31,	
	2015	2014
Weighted average common shares outstanding		
Basic	73,819	65,684
Dilutive effect of options, restricted stock units and preferred shares	—	545
Diluted weighted average common shares outstanding	73,819	66,229

A total of 2.5 million options to purchase shares of the Company's common stock, 0.2 million restricted stock units and 150,000 preferred shares were excluded from the calculations above for the three months ended March 31, 2015 because their effects were anti-dilutive. Additionally, 0.8 million restricted shares, which are participating securities, were excluded from the calculations above for the three months ended March 31, 2015 as the security holders do not have the obligation to share in the losses of the Company.

Fair Value Measurements

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

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

Recent Accounting Pronouncements

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

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 beginning after December 31, 2015 and interim periods within fiscal years beginning after December 15, 2016. The impact of the adoption of this ASU on the Company's financial statements will be to reduce total assets and total liabilities by the carrying value of unamortized debt issuance costs at the time of adoption.

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 which it 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 Matador's existing acreage in its Ranger and Rustler Breaks prospect areas through a merger of HEYCO with and into a wholly-owned subsidiary of Matador (the "HEYCO Merger"). 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 months ended March 31, 2015, the Company incurred approximately $2.2 million of transaction costs associated with the HEYCO Merger. These costs are recorded in general and administrative expenses for the three months ended March 31, 2015. 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 our revenues or results of operations. Therefore, pro forma financial information for the HEYCO Merger is not presented as the effects are not material to the Company's consolidated results. Included in the Statement of Operations for the three months ended March 31, 2015 is revenue attributable to the operations acquired in the HEYCO Merger of approximately $0.7 million.

10

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

NOTE 3 - BUSINESS COMBINATION - Continued

The preliminary allocation of the consideration given related to this business combination, which is subject to change, was as follows.

Consideration given		
Cash	$24,648	
Preferred shares issued	32,490	
Common shares issued	71,478	
Total consideration given	$128,616	
Allocation of purchase price		
Cash acquired	$620	
Accounts receivable	3,536	
Inventory	180	
Other current assets	106	
Oil and natural gas properties		
Evaluated oil and natural gas properties	22,044	
Unproved oil and unevaluated natural gas properties	194,686	
Accounts payable	(2,551	)
Accrued liabilities	(11	)
Current note payable	(11,982	)
Asset retirement obligations	(2,046	)
Deferred tax liabilities incurred	(75,966	)
Net assets acquired	$128,616	

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. (convertible into ten shares of common stock for each one share of Preferred Stock) 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. Each share of Series A Preferred Stock would be entitled to ten votes on each matter submitted to Matador's shareholders for vote. Beginning on August 27, 2015 and until such time as the Series A Preferred Stock was converted to common stock, the holders would be entitled to a quarterly dividend of $1.80 per share. 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. The 150,000 outstanding shares of Series A Preferred Stock converted to 1,500,000 shares of common stock on April 6, 2015, following shareholder approval of the amendment to our Amended and Restated Certificate of Formation.

On April 21, 2015, the Company completed a public offering of 7,000,000 shares of its common stock. After deducting direct offering costs totaling approximately $1.6 million, the Company received net proceeds of approximately $187.1 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 $102.1 million of net proceeds is being used to fund a portion of the Company's working capital expenditures, including the possible

NOTE 4 - EQUITY - Continued

addition of a third drilling rig in the Permian Basin as early as late summer 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. Pending such uses, the Company plans to invest the remaining proceeds in short-term marketable securities.

All shares of treasury stock outstanding at March 31, 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 three months ended March 31, 2015 (in thousands).

Beginning asset retirement obligations	$11,951
Liabilities incurred during period	2,404
Liabilities settled during period	(221)
Revisions in estimated cash flows	(703)
Accretion expense	112
Ending asset retirement obligations	13,543
Less: current asset retirement obligations[1]	(268)
Long-term asset retirement obligations	$13,275

(1) Included in accrued liabilities in the Company's unaudited condensed consolidated balance sheet at March 31, 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 March 31, 2015, directly or indirectly owns the ownership interests in the Company's other operating subsidiaries other than one less-than-wholly-owned subsidiary and MRC Delaware Resources, LLC. Borrowings are secured by mortgages on substantially all of the Company's proved oil and natural gas properties and by the equity interests of certain of MRC Energy Company's wholly-owned subsidiaries, which are also guarantors. In addition, all obligations under the Credit Agreement are guaranteed by Matador, the parent corporation. Various commodity hedging agreements with certain of the lenders under the Credit Agreement (or affiliates thereof) are also secured by the collateral of and guaranteed by certain eligible subsidiaries of MRC Energy Company.

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of the Company's proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. Both the Company and the lenders may request an unscheduled redetermination of the borrowing base once each between scheduled redetermination dates. During the 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 were $1.6 million at March 31, 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

NOTE 6 - DEBT - Continued

collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or to repay the deficit in equal installments over a period of six months.

At March 31, 2015, the Company had $410.0 million in borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. For the three months ended March 31, 2015, the Company's outstanding borrowings bore interest at an effective interest rate of approximately 2.9% per annum. On April 14, 2015, using a portion of the net proceeds from the senior unsecured notes offering discussed herein, the Company repaid $380.0 million of its outstanding borrowings under the Credit Agreement. From April 14, 2015 through April 23, 2015, the Company borrowed $55.0 million under the Credit Agreement to finance a portion of its working capital requirements and capital expenditures and the acquisition of additional leasehold interests. On April 24, 2015, using a portion of the net proceeds from the April 2015 public offering of common stock discussed herein, the Company repaid the $85.0 million of outstanding borrowings under the Credit Agreement. At May 6, 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.

As of March 31, 2015, if the Company borrows funds as a base rate loan, such borrowings will bear interest at a rate equal to the higher of (i) the prime rate for such day, (ii) the Federal Funds Effective Rate (as defined in the Credit Agreement) on such day, plus 0.50% or (iii) the daily adjusting LIBOR rate (as defined in the Credit Agreement) plus 1.0% plus, in each case, an amount from 0.50% to 2.75% of such outstanding loan depending on the level of borrowings under the agreement. If the Company borrows funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (i) the quotient obtained by dividing (A) the LIBOR rate by (B) a percentage equal to 100% minus the maximum rate during such interest calculation period at which Royal Bank of Canada ("RBC") is required to maintain reserves on Eurocurrency Liabilities (as defined in Regulation D of the Board of Governors of the Federal Reserve System) plus (ii) an amount from 1.50% to 3.75% of such outstanding loan depending on the level of borrowings under the Credit Agreement. The interest period for Eurodollar borrowings may be one, two, three or six months as designated by the Company. A commitment fee of 0.375% to 0.50%, depending on the unused availability under the Credit Agreement, is also paid quarterly in arrears. The Company includes this commitment fee, any amortization of deferred financing costs (including origination, borrowing base increase and amendment fees) and annual agency fees, if any, as interest expense and in its interest rate calculations and related disclosures. The Credit Agreement requires the Company to maintain a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.25 or less.

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

- incur indebtedness or grant liens on any of the Company's assets;
- enter into commodity hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates;
- 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 March 31, 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 of approximately $392.0 million, after deducting the initial purchasers’ discounts and estimated offering expenses, 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,

14

NOTE 6 - DEBT - Continued

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

Current Note Payable

In connection with the HEYCO Merger, Matador 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 of Matador were terminated.

NOTE 7 - INCOME TAXES

The Company had an effective tax rate of 34.4% for the three months ended March 31, 2015. Total income tax benefit for the three months ended March 31, 2015 differed from amounts computed by applying the U.S. federal statutory tax rate to pre-tax loss due primarily to the impact of permanent differences between book and taxable income. The total income tax benefit of $26.4 million for the three months ended March 31, 2015 includes $24.3 million of deferred income tax benefit resulting from the full-cost ceiling impairment. Based upon its projections for the remainder of 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 months ended March 31, 2014. The Company had an effective tax rate of 36.8% for the three months ended March 31, 2014. Total income tax expense for the three months ended March 31, 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.

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 was approximately $8.4 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 prices. These instruments consist of put and call options in the form of costless collars and swap contracts. The Company records derivative financial instruments in its consolidated balance sheet as either assets or liabilities measured at fair value. The Company has elected not to apply hedge accounting for its existing derivative financial instruments. As a result, the Company recognizes the change in derivative fair value between reporting periods currently in its consolidated statement of operations as an unrealized gain or unrealized loss. The fair value of the

Table of Contents

NOTE 9 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

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 March 31, 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 natural gas liquids (“NGL”) prices, each with an established fixed price. For each calculation period, the settlement price for determining the realized gain or loss to the Company pursuant to any of these transactions is the arithmetic average of any current month for delivery on the nearby month futures contracts of the underlying commodity as stated on the “Mont Belvieu Spot Gas Liquids Prices: NON-TET prop” on the pricing date. When the settlement price is below the fixed price established by one or more of these swaps, the Company receives from the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract NGL volume. When the settlement price is above the fixed price established by one or more of these swaps, the Company pays to the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract NGL volume.

At March 31, 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 March 31, 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.

Table of Contents

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

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 March 31, 2015.

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil	04/01/2015 - 12/31/2015	20,000	80.00	100.00	$4,974
Oil	04/01/2015 - 12/31/2015	20,000	80.00	101.00	4,978
Oil	04/01/2015 - 12/31/2015	20,000	83.00	96.12	5,499
Oil	04/01/2015 - 12/31/2015	20,000	83.00	97.00	5,499
Oil	04/01/2015 - 12/31/2015	20,000	85.00	99.00	5,855
Oil	04/01/2015 - 12/31/2015	20,000	85.00	100.00	5,855
Oil	04/01/2015 - 12/31/2015	20,000	85.00	105.10	5,855
Total open oil costless collar contracts					38,515

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas	04/01/2015 - 10/31/2015	150,000	2.75	3.19	154
Natural Gas	04/01/2015 - 12/31/2015	100,000	2.75	3.05	66
Natural Gas	04/01/2015 - 12/31/2015	100,000	2.75	3.15	89
Natural Gas	04/01/2015 - 12/31/2015	100,000	2.75	3.11	80
Natural Gas	04/01/2014 - 12/31/2015	300,000	2.88	3.18	490
Natural Gas	04/01/2015 - 12/31/2015	100,000	3.75	4.36	891
Natural Gas	04/01/2015 - 12/31/2015	100,000	3.75	4.45	892
Natural Gas	04/01/2015 - 12/31/2015	100,000	3.75	4.60	895
Natural Gas	04/01/2015 - 12/31/2015	100,000	3.75	4.65	888
Natural Gas	04/01/2015 - 12/31/2015	200,000	3.75	5.04	1,799
Natural Gas	04/01/2015 - 12/31/2015	100,000	3.75	5.34	900
Natural Gas	01/01/2016 - 12/31/2016	200,000	2.75	3.50	(65)
Total open natural gas costless collar contracts					7,079

Commodity	Calculation Period	Notional Quantity (Gal/month)	Fixed Price ($/Gal)	Fair Value of Asset (Liability) (thousands)
Propane	04/01/2015 - 12/31/2015	150,000	1.000	626
Propane	04/01/2015 - 12/31/2015	100,000	1.030	444
Propane	04/01/2015 - 12/31/2015	68,000	1.073	328
Total open NGL swap contracts				1,398
Total open derivative financial instruments				$46,992

These derivative financial instruments are subject to master netting arrangements within specific commodity types, i.e., oil, natural gas and NGL, by counterparty. Derivative financial instruments with Counterparty A are not subject to master netting across commodity types, while derivative financial instruments with Counterparties B, C and D 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.

NOTE 9 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The following table presents the gross asset balances of the Company's derivative financial instruments, the amounts subject to master netting arrangements, the amounts that the Company has presented on a net basis, the amounts subject to master netting across different commodity types that were presented on a gross basis and the location of these balances in its unaudited condensed consolidated balance sheet as of March 31, 2015 (in thousands).

Derivative Instruments	Gross amounts of recognized assets	Gross amounts netted in the condensed consolidated balance sheet	Net amounts of assets presented in the condensed consolidated balance sheet	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current assets	$11,372	$(17)	$11,355	$—
Other assets	—	—	—	—
Counterparty B				
Current assets	7,683	(19)	7,664	—
Other assets	—	—	—	—
Counterparty C				
Current assets	22,186	(950)	21,236	—
Other assets	359	(359)	—	—
Counterparty D				
Current assets	6,764	(8)	6,756	—
Other assets	—	—	—	—
Total	$48,364	$(1,353)	$47,011	$—

The following table presents the gross liability balances of the Company's derivative financial instruments, the amounts subject to master netting arrangements, the amounts that the Company has presented on a net basis, the amounts subject to master netting across different commodity types that were presented on a gross basis and the location of these balances in its unaudited condensed consolidated balance sheet as of March 31, 2015 (in thousands).

Derivative Instruments	Gross amounts of recognized liabilities	Gross amounts netted in the condensed consolidated balance sheet	Net amounts of liabilities presented in the condensed consolidated balance sheet	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current liabilities	$17	$(17)	$—	$—
Other liabilities	—	—	—	—
Counterparty B				
Current liabilities	19	(19)	—	—
Other liabilities	—	—	—	—
Counterparty C				
Current liabilities	950	(950)	—	—
Other liabilities	378	(359)	19	—
Counterparty D				
Current liabilities	8	(8)	—	—

Other liabilities	—	—	—	—
Total	$1,372	$(1,353)	$19	$—

18

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

NOTE 9 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The following table presents the gross asset balances of the Company's derivative financial instruments, the amounts subject to master netting arrangements, the amounts that the Company has presented on a net basis, the amounts subject to master netting across different commodity types that were presented on a gross basis and the location of these balances in its unaudited condensed consolidated balance sheet as of December 31, 2014 (in thousands).

Derivative Instruments	Gross amounts of recognized assets	Gross amounts netted in the condensed consolidated balance sheet	Net amounts of assets presented in the condensed consolidated balance sheet	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current assets	$13,437	$(157)	$13,280	$—
Other assets	—	—	—	—
Counterparty B				
Current assets	8,759	(116)	8,643	—
Other assets	—	—	—	—
Counterparty C				
Current assets	25,685	(368)	25,317	—
Other assets	—	—	—	—
Counterparty D				
Current assets	8,374	(65)	8,309	—
Other assets	—	—	—	—
Total	$56,255	$(706)	$55,549	$—

The following table presents the gross liability balances of the Company's derivative financial instruments, the amounts subject to master netting arrangements, the amounts that the Company has presented on a net basis, the amounts subject to master netting across different commodity types that were presented on a gross basis and the location of these balances in its unaudited condensed consolidated balance sheet as of December 31, 2014 (in thousands).

Derivative Instruments	Gross amounts of recognized liabilities	Gross amounts netted in the condensed consolidated balance sheet	Net amounts of liabilities presented in the condensed consolidated balance sheet	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current liabilities	$157	$(157)	$—	$—
Other liabilities	—	—	—	—
Counterparty B				
Current liabilities	116	(116)	—	—
Other liabilities	—	—	—	—
Counterparty C				
Current liabilities	368	(368)	—	—
Other liabilities	—	—	—	—
Counterparty D				

Current liabilities	65	(65)	—	—
Other liabilities	—	—	—	—
Total	$706	$(706)	$—	$—

19

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

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.

Type of Instrument	Location in Condensed Consolidated Statement of Operations	Three Months Ended March 31, 2015	2014
Derivative Instrument			
Oil	Revenues: Realized gain (loss) on derivatives	$14,433	$(942)
Natural Gas	Revenues: Realized gain (loss) on derivatives	3,600	(589)
NGL	Revenues: Realized gain (loss) on derivatives	471	(312)
Realized gain (loss) on derivatives		18,504	(1,843)
Oil	Revenues: Unrealized loss on derivatives	(6,464)	(2,050)
Natural Gas	Revenues: Unrealized loss on derivatives	(1,563)	(1,267)
NGL	Revenues: Unrealized (loss) gain on derivatives	(530)	209
Unrealized loss on derivatives		(8,557)	(3,108)
Total		$9,947	$(4,951)

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.

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

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

At March 31, 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, note payable, advances from joint interest owners, income taxes payable and other current liabilities approximate their fair values due to their short-term maturities.

At March 31, 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 that reflect market rates available to the Company at the time, and is classified at Level 2.

Table of Contents

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

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 March 31, 2015 and December 31, 2014 (in thousands).

	Fair Value Measurements at March 31, 2015 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Oil, natural gas and NGL derivatives	$—	$47,011	$—	$47,011
Oil, natural gas and NGL derivatives	—	(19)	—	(19)
Total	$—	$46,992	$—	$46,992

	Fair Value Measurements at December 31, 2014 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
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. For purposes of fair value measurement, the Company determined that derivative financial instruments (e.g., oil, natural gas and NGL derivatives) should be classified at Level 2.

The Company accounts for additions and revisions to asset retirement obligations and lease and well equipment inventory when adjusted for impairment at fair value on a non-recurring basis and has determined that these fair value measurements should be classified at Level 3. The following tables summarize the valuation of the Company's assets and liabilities that were accounted for at fair value on a non-recurring basis for the periods ended March 31, 2015 and December 31, 2014 (in thousands).

	Fair Value Measurements at March 31, 2015 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$—	$—	$(1,701)	$(1,701)
Total	$—	$—	$(1,701)	$(1,701)

	Fair Value Measurements at December 31, 2014 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$—	$—	$(3,985)	$(3,985)
Total	$—	$—	$(3,985)	$(3,985)

No impairment to any equipment was recorded during the three months ended March 31, 2015 and December 31, 2014. Reconciliations for the Company's asset retirement obligations at March 31, 2015 are provided in Note 5.

NOTE 11 - COMMITMENTS AND CONTINGENCIES

Natural Gas and NGL Processing and Transportation Commitments

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

Under this agreement, if the Company does not meet 80% of the maximum thermal quantity transportation and processing commitments in a contract year, it will be required to pay a deficiency fee per MMBtu of natural gas deficiency. Any quantity in excess of the maximum MMBtu delivered in a contract year can be carried over to the next contract year for purposes of calculating the natural gas deficiency. During certain prior periods, the Company had an immaterial natural gas deficiency, and the counterparty to this agreement waived the deficiency fee. The Company’s remaining aggregate undiscounted minimum commitments under this agreement are $5.3 million at March 31, 2015. The Company paid $1.3 million and $1.2 million in processing and transportation fees under this agreement during the three months ended March 31, 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 $45.0 million at March 31, 2015.

The Company 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 the 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 $5.2 million during the three months ended March 31, 2015. The Company made no payments under this contract during the three months ended March 31, 2014. The plant is scheduled to be completed and placed in service in the third quarter of 2015.

At March 31, 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 $18.6 million at March 31, 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.

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

NOTE 12 - SUPPLEMENTAL DISCLOSURES

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

	March 31, 2015	December 31, 2014
Accrued evaluated and unproved and unevaluated property costs	$96,432	$86,259
Accrued support equipment and facilities costs	11,302	4,290
Accrued stock-based compensation	325	—
Accrued lease operating expenses	7,942	9,034
Accrued interest on borrowings under Credit Agreement	292	206
Accrued asset retirement obligations	268	311
Accrued partners' share of joint interest charges	6,516	3,767
Other	5,768	5,635
Total accrued liabilities	$128,845	$109,502

Supplemental Cash Flow Information
The following table provides supplemental disclosures of cash flow information for the three months ended March 31, 2015 and 2014 (in thousands).

	Three Months Ended March 31,	
	2015	2014
Cash paid for interest expense, net of amounts capitalized	$1,990	$1,269
Asset retirement obligations related to mineral properties	1,507	1,715
Asset retirement obligations related to support equipment and facilities	32	111
Increase in liabilities for oil and natural gas properties capital expenditures	8,654	42,012
Increase in liabilities for support equipment and facilities	6,865	437
Issuance of restricted stock units for Board and advisor services	142	96
Issuance of common stock for advisor services	4	6
Stock-based compensation expense recognized as liability	263	677
Transfer of inventory from oil and natural gas properties	310	107

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). As of March 31, 2015, the Guarantor Subsidiaries are 100% owned by Matador, and any subsidiaries of Matador other than the Notes 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. As of March 31, 2015, the Company had no outstanding debt securities.

Table of Contents

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. 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;

Table of Contents

- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- the merger of our wholly-owned subsidiary with Harvey E. Yates Company;
- our costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- competition in the oil and natural gas industry;
- the effectiveness of our risk management and hedging activities;
- environmental liabilities;
- counterparty credit risk;
- developments in oil-producing and natural gas-producing countries;
- our future operating results;
- estimated future reserves and the present value thereof;
- our plans, objectives, expectations and intentions contained in this Quarterly Report that are not historical; and
- other factors discussed in the Annual Report.

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

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

Overview

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Our current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Permian 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.

First Quarter Highlights

Quarterly production results for the first quarter of 2015 were the best in our Company’s history. Our total oil equivalent production for the first quarter of 2015 was 2.1 million BOE, and our average daily oil equivalent production for the first quarter of 2015 was 23,513 BOE per day, of which 11,206 Bbl per day, or 48%, was oil and 73.8 MMcf per day, or 52%, was natural gas. Our average daily oil production of 11,206 Bbl per day, our total natural gas production of 6.6 Bcf and our average daily natural gas production of 73.8 MMcf per day for the first quarter of 2015 were also record quarterly results.

During the first quarter of 2015, our oil and natural gas revenues were $62.5 million, a decrease of 21% from oil and natural gas revenues of $78.9 million during the first quarter of 2014. This decrease was attributable to a sharp decline in the weighted average oil and natural gas prices we realized to $43.37 per Bbl and $2.82 per Mcf, respectively, in the first quarter of 2015 from weighted average oil and natural gas prices of $96.34 per Bbl and $6.20 per Mcf, respectively, in the first quarter of 2014. The decrease in our oil and natural gas revenues was partially offset by the 53% increase in our oil production to 1.0 million Bbl in the first quarter of 2015, as compared to 661,000 Bbl produced in the first quarter of 2014. This increase in oil production was primarily a result of our ongoing development activities in the Eagle Ford shale, as well as better-than-expected initial production contributions from newly drilled wells in the Permian Basin. For the three months ended March 31, 2015, our Adjusted EBITDA was $50.1 million, a decrease of 11% from Adjusted EBITDA of $56.3 million during the three months ended March 31,

2014. Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a

25

Table of Contents

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 strategically located between our existing acreage in our Ranger and Rustler Breaks prospect areas in Lea and Eddy Counties, New Mexico (the "HEYCO Merger"). The approximately 58,600 gross (18,200 net) acres we obtained in the HEYCO Merger increased our acreage position in the Permian Basin to approximately 152,400 gross (85,400 net) acres at March 31, 2015.

As consideration for the HEYCO Merger, we paid approximately $21.6 million in cash, 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 the Company's convertible preferred stock (the "Series A Preferred Stock") to HEYCO Energy Group, Inc. In addition, we paid $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, we incurred deferred tax liabilities of approximately $76.0 million and assumed other liabilities of approximately $4.6 million. Pursuant to the terms of the merger agreement, 125,000 of the 150,000 shares of Series A Preferred Stock issued upon the closing of the HEYCO Merger were placed into escrow to satisfy post-closing adjustments to the merger consideration for certain title or environmental defects on the HEYCO assets. 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.

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, using a portion of the net proceeds from our senior unsecured notes offering discussed below, we repaid $380.0 million in outstanding borrowings under our Credit Agreement. From April 14, 2015 through April 23, 2015, we borrowed $55.0 million under the Credit Agreement to finance a portion of our working capital requirements and capital expenditures and the acquisition of additional leasehold interests. On April 24, 2015, using a portion of the net proceeds from our April 2015 public offering of common stock discussed below, we repaid the $85.0 million of outstanding borrowings under our Credit Agreement. At May 6, 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.

On April 14, 2015, we issued $400.0 million of our 6.875% senior notes due 2023 (the "Notes"). The Notes are our senior unsecured obligations and were issued at par value. The net proceeds of approximately $392.0 million, after deducting the initial purchasers' discounts and estimated offering expenses, were used to pay down $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.

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 $1.6 million, we received net proceeds of approximately $187.1 million. We used a portion of the net proceeds to repay $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 $102.1 million of net proceeds is being used to fund a portion of our capital expenditures, including the possible addition of a third drilling rig in the Permian Basin as early as late summer 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. Pending such uses, we plan to invest the remaining proceeds in short-term marketable securities.

We were operating five drilling rigs, two rigs in the Eagle Ford and three rigs in the Permian Basin, at the beginning of 2015, but had reduced our operated drilling rigs to two by the end of the first quarter of 2015, with both operating in the Permian Basin. We are currently running two drilling rigs in the Permian Basin, one in Loving County, Texas and the other in Eddy County, New Mexico, and currently plan to operate at least two drilling rigs in the Permian Basin for the remainder of 2015. We are now considering adding a third drilling rig in the Permian Basin as early as late summer 2015 depending on commodity prices and improved well economics resulting from higher recoveries, realized savings from various operating efficiencies and cost savings from vendors. 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. We expect to fund our remaining 2015 capital expenditure budget through a combination of cash on hand, operating cash flows, borrowings under our revolving credit facility (assuming availability under our borrowing base), the net proceeds from the offering of the Notes described above and the offering of common stock described above, potential joint ventures and the potential sale of assets or acreage. At March 31, 2015, we had incurred $159.0 million, or approximately 45%, of our anticipated 2015 capital expenditure budget of $350.0 million (excluding capital expenditures associated with the HEYCO Merger).

During the first quarter of 2015, we completed and began producing oil and natural gas from five gross (3.5 net) wells in the Permian Basin, including four gross (3.4 net) operated wells and one gross (0.1 net) non-operated well. We completed two operated wells in our Wolf prospect area in Loving County, Texas — the Barnett 90-TTT-B01-WF #201H and the Barnett 90-TTT-B01-WF #205H wells — and two operated wells in our Rustler Breaks prospect area in Eddy County, New Mexico — the Guitar 10-24S-28E RB #202H and the Tiger 14-24S-28E RB #224H wells. The Barnett 90-TTT-B01-WF #201H and the Barnett 90-TTT-B01-WF #205H wells began producing in February, and the Guitar 10-24S-28E RB #202H and the Tiger 14-24S-28E RB #224H wells were completed and began producing in late March. As a result, these four wells did not contribute fully to production volumes for the first quarter of 2015. Nonetheless, our Permian Basin production has increased significantly in the past year. Our total Permian Basin production for the first quarter of 2015 was 3,546 BOE per day, consisting of 2,467 Bbl of oil per day and 6.5 MMcf of natural gas per day, more than triple our Permian Basin total production of 1,066 BOE per day, consisting of 904 Bbl of oil per day and 1.0 MMcf of natural gas per day, in the first quarter of 2014. The Permian Basin contributed approximately 22% of our daily oil production and approximately 9% of our daily natural gas production in the first quarter of 2015, as compared to only about 12% of our daily oil production and approximately 4% of our daily natural gas production in the first quarter of 2014.

In the Wolf prospect area in Loving County, Texas, the Barnett 90-TTT-B01-WF #205H and the Barnett 90-TTT-B01-WF #201H wells were drilled on 80-acre spacing from the same drilling pad. The Barnett 90-TTT-B01-WF #205H was drilled and completed in the Wolfcamp “A”/“Y” sand, just below the “A”/“X” sand, at approximately 11,000 feet true vertical depth. This was our first test of the Wolfcamp “A”/“Y” interval in the Wolf prospect area. This well had a completed lateral length of 4,376 feet, and we completed the well with 17 frac stages, including approximately 140,000 barrels of fluid and 7.1 million pounds of sand. The Barnett 90 TTT-B01-WF #201H was drilled and completed in the Wolfcamp “A”/“X” sand at the top of the Wolfcamp formation at approximately 10,900 feet true vertical depth. This is the zone that most of our horizontal completions in the Wolf prospect have targeted thus far. This well had a completed lateral length of 4,318 feet, and we completed the well with 21 frac stages, including approximately 175,000 barrels of fluid and 8.9 million pounds of sand. During its 24-hour initial potential test, the Barnett 90-TTT-WF #205H well, the Wolfcamp “A”/“Y” completion, flowed 1,377 BOE per day (54% oil), consisting of 738 Bbl of oil per day and 3.8 MMcf of natural gas per day, at 3,475 pounds per square inch (“psi”) on a 26/64th inch choke. We believe this initial test of the Wolfcamp “A”/“Y” sand establishes this zone as another potential completion horizon for us in the upper Wolfcamp in the Wolf prospect area. During its 24-hour initial potential test, the Barnett 90-TTT-WF #201H, the Wolfcamp “A”/“X” completion, flowed 1,268 BOE per day (57% oil), consisting of 720 Bbl of oil per day and 3.3 MMcf of natural gas per day, at 3,225 psi on a 26/64th inch choke. We plan to monitor the performance of these two 80-acre spaced wells closely to determine if these two zones can be effectively developed in a staggered “W”-type pattern on 80-acre spacing going forward. We are currently running one drilling rig in our Wolf prospect area and plan to continue running one drilling rig in this area for the remainder of 2015.

In the Rustler Breaks prospect area in Eddy County, New Mexico, the Guitar 10-24S-28E RB #202H and the Tiger 14-24S-28E RB #224H wells tested two new horizons within the Wolfcamp formation. The Guitar 10-24S-28E RB #202H well was drilled and completed in the Wolfcamp “A”/“X-Y” sand at the top of the Wolfcamp “A” formation at approximately 9,550 feet true vertical depth. This well had a completed lateral length of 4,232 feet, and we completed the well with 18 frac stages, including approximately 164,000 barrels of fluid and 8.3 million pounds of sand. During its 24-hour initial potential test, the Guitar 10-24S-28E RB #202H well flowed 1,273 BOE per day (79% oil), consisting of 1,008 Bbl of oil per day and 1.6 MMcf of natural gas per day, at 2,190 psi on a 26/64th inch choke. To our knowledge, this was one of the first wells to test the Wolfcamp “A”/“X-Y” sand horizontally in southern Eddy County, New Mexico. This interval is the stratigraphic equivalent of the highly productive Wolfcamp “A”/“X-Y” intervals being completed in our Wolf prospect in Loving County, Texas. The Tiger 14-24S-28E RB #224H well was drilled and completed in the lower portion of the Wolfcamp “B” formation at approximately 10,500 feet true vertical depth. This

Wolfcamp “B” target is approximately 300 feet lower stratigraphically than the zone from which the Rustler Breaks 12-24S-27E RB#224H well (formerly the Rustler Breaks 12-24-27 #1H), our initial Wolfcamp “B” well in the Rustler Breaks prospect area, is producing. The Tiger 14-24S-28E RB #224H well had a completed lateral length of 4,376 feet, and we completed the well with 21 frac stages, including approximately 170,000 barrels of fluid and 8.8 million pounds of sand. During its 24-hour initial potential test, the well flowed 1,525 BOE per day (43% oil), consisting of 650 Bbl of oil per day and 5.3 MMcf of natural gas per day, at 3,900 psi on a 26/64th inch choke. This successful test of the lower portion of the Wolfcamp “B” was also encouraging because we believe that the upper and lower portions of the Wolfcamp “B” may be even more effectively developed in a staggered “W”-type pattern on 80-acre spacing. We are currently running one rig in the Rustler Breaks prospect area and plan to continue running one rig in Eddy and Lea Counties, New Mexico for the remainder of 2015.

Table of Contents

During the first quarter of 2015, we completed and began producing oil and natural gas from 14 gross (14.0 net) Eagle Ford wells, all of which were operated wells. We completed four Eagle Ford wells on our Pena lease in La Salle County, two wells on our Thiel Martin lease in La Salle County and eight wells on our Bishop-Brogan lease in Karnes County, Texas. The Pena wells began producing in early-to-mid-January, the Thiel Martin wells began producing in early February and the Bishop-Brogan wells began producing in late March. As a result, these wells did not contribute fully to production volumes for the first quarter of 2015. Since March 31, 2015, we have completed and placed on production three gross (3.0 net) additional Eagle Ford wells. 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.

The eight wells on our Bishop-Brogan properties located adjacent to our Danysh/Pawelek leases on our central acreage in Karnes County were developed using the batch drilling method in groups of four wells each on approximately 40-acre spacing and were completed with our Generation 7 fracture treatment. The eight wells had average initial production rates of 902 BOE per day (88% oil) on 14/64th inch chokes at an average flowing casing pressure of 3,105 psi, making them some of the best wells we have drilled in the Eagle Ford shale play. The combination of operational efficiencies from batch development and other drilling improvements and service cost reductions resulted in an average well cost of approximately $5.3 million for these Bishop-Brogan wells, which was almost 20% below original estimates and resulted in aggregate savings of about $9 million compared to the costs originally budgeted for these eight wells. We intend to use many of these improved drilling and completion practices in our Wolf, Ranger, Rustler Breaks and Twin Lakes prospect areas in Southeast New Mexico and West Texas as we continue our delineation and development efforts in our Permian Basin operations.

We continue to be pleased with the performance of various Haynesville shale wells being completed and placed on production by Chesapeake in our Elm Grove properties in Northwest Louisiana. Chesapeake placed seven gross (1.2 net) additional Haynesville shale wells on production in the first quarter of 2015. These wells had initial production rates ranging from 12 to 15 MMcf of natural gas per day (gross) at flowing tubing pressures of 6,000 to 8,000 psi. Further, Chesapeake drilled and completed these wells for an average of $7 to $8 million, below our expectations. Along with the 14 gross (3.3 net) Haynesville wells Chesapeake placed on production in 2014, these new wells have contributed to a significant increase in our natural gas production rate from approximately 58 MMcf of natural gas per day in the fourth quarter of 2014 to approximately 80 MMcf of natural gas per day in the last two weeks of March 2015. Our average daily natural gas production from the Haynesville increased more than five-fold year-over-year from about 9.5 MMcf per day in the first quarter of 2014 to 50.6 MMcf per day in the first quarter of 2015.

At March 31, 2015, our estimated total proved oil and natural gas reserves were 79.3 million BOE, including 32.5 million Bbl of oil and 280.5 Bcf of natural gas, with a PV-10 of $1.07 billion and a Standardized Measure of $949.2 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 March 31, 2014, our estimated proved oil and natural gas reserves were 54.6 million BOE, including 16.9 million Bbl of oil and 225.9 Bcf of natural gas. Our proved oil reserves of 32.5 million Bbl at March 31, 2015 increased 92%, as compared to 16.9 million Bbl at March 31, 2014, and 34%, as compared to 24.2 million Bbl at December 31, 2014. These reserves estimates were based on evaluations prepared by our engineering staff and, with respect to the reserves at March 31, 2015 and December 31, 2014, 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 $43.37 per Bbl for the three months ended March 31, 2015, as compared to $96.34 per Bbl for the three months ended March 31, 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 $2.82 per Mcf for the three months ended March 31, 2015, as compared to $6.20 per Mcf for the three months ended March 31, 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 first quarter of 2015.
Estimated Proved Reserves
The following table sets forth our estimated total proved oil and natural gas reserves at March 31, 2015, December 31, 2014 and March 31, 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, with respect to the reserves estimates at March 31, 2015 and December 31, 2014, 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

Table of Contents

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.

	March 31, 2015	December 31, 2014	March 31, 2014
Estimated Proved Reserves Data: (1) (2)			
Estimated proved reserves:			
Oil (MBbl)(3)	32,506	24,184	16,919
Natural Gas (Bcf)(4)	280.5	267.1	225.9
Total (MBOE)(5)	79,262	68,693	54,563
Estimated proved developed reserves:			
Oil (MBbl)(3)	15,889	14,053	8,999
Natural Gas (Bcf)(4)	104.7	102.8	56.1
Total (MBOE)(5)	33,340	31,185	18,349
Percent developed	42.1 %	45.4 %	33.6 %
Estimated proved undeveloped reserves:			
Oil (MBbl)(3)	16,617	10,131	7,920
Natural Gas (Bcf)(4)	175.8	164.3	169.8
Total (MBOE)(5)	45,922	37,508	36,214
PV-10(6) (in millions)	$1,070.1	$1,043.4	$739.8
Standardized Measure(7) (in millions)	$949.2	$913.3	$653.6

(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 April 2014 through March 2015 were $79.21 per Bbl for oil and $3.882 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 April 2013 through March 2014 were $94.92 per Bbl for oil and $3.989 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 March 31, 2015, December 31, 2014 and March 31, 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 March 31, 2015, December 31, 2014 and March 31, 2014 were, in millions, $120.9, $130.1 and $86.2, 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.

Table of Contents

At March 31, 2015, our estimated total proved oil and natural gas reserves were 79.3 million BOE, including 32.5 million Bbl of oil and 280.5 Bcf of natural gas, with a PV-10 of $1.07 billion and a Standardized Measure of $949.2 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 March 31, 2014, our estimated total proved oil and natural gas reserves were 54.6 million BOE, including 16.9 million Bbl of oil and 225.9 Bcf of natural gas. Our proved oil reserves of 32.5 million Bbl at March 31, 2015 increased 34%, as compared to 24.2 million Bbl at December 31, 2014, and 92%, as compared to 16.9 million Bbl at March 31, 2014. During the three months ended March 31, 2015, our proved developed reserves increased 7% from 31.2 million BOE at December 31, 2014 to 33.3 million BOE at March 31, 2015. Year-over-year, our proved developed reserves increased 82% from 18.3 million BOE at March 31, 2014. At March 31, 2015, approximately 42% of our total proved reserves were proved developed reserves, 41% of our total proved reserves were oil and 59% 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, 2016, i.e., in our first fiscal quarter of 2017. We are currently evaluating the impact, if any, of the adoption of this ASU on our consolidated financial statements.

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 beginning after December 31, 2015 and interim periods within fiscal years beginning after December 15, 2016. The impact of the adoption of this ASU on the Company’s financial statements will be to reduce total assets and total liabilities by the carrying value of unamortized debt issuance costs at the time of adoption.

Table of Contents

Results of Operations

Revenues

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

	Three Months Ended March 31, 2015 (Unaudited)	Three Months Ended March 31, 2014 (Unaudited)
Operating Data:		
Revenues (in thousands):[1]		
Oil	$43,736	$ 63,674
Natural gas	18,729	15,257
Total oil and natural gas revenues	62,465	78,931
Realized gain (loss) on derivatives	18,504	(1,843)
Unrealized loss on derivatives	(8,557)	(3,108)
Total revenues	$72,412	$ 73,980
Net Production Volumes:[1]		
Oil (MBbl)[2]	1,009	661
Natural gas (Bcf)[3]	6.6	2.5
Total oil equivalent (MBOE)[4]	2,116	1,071
Average daily production (BOE/d)[5]	23,513	11,904
Average Sales Prices:		
Oil, with realized derivatives (per Bbl)	$57.68	$ 94.91
Oil, without realized derivatives (per Bbl)	$43.37	$ 96.34
Natural gas, with realized derivatives (per Mcf)	$3.43	$ 5.83
Natural gas, without realized derivatives (per Mcf)	$2.82	$ 6.20

(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 March 31, 2015 as Compared to Three Months Ended March 31, 2014

Oil and natural gas revenues. Our oil and natural gas revenues decreased by $16.5 million to $62.5 million, or a decrease of 21%, for the three months ended March 31, 2015, as compared to $78.9 million for the three months ended March 31, 2014. This decrease in oil and natural gas revenues includes a decrease in our oil revenues of $19.9 million and an increase in our natural gas revenues of $3.5 million for the three months ended March 31, 2015, as compared to the three months ended March 31, 2014. Our oil revenues decreased by $19.9 million, or 31%, to $43.7 million for the three months ended March 31, 2015, as compared to $63.7 million for the three months ended March 31, 2014. Our oil production increased by 53% to 1.0 million Bbl of oil in the first quarter of 2015, or 11,206 Bbl of oil per day, as compared to 661,000 Bbl of oil in the first quarter of 2014, or 7,344 Bbl of oil per day. This increase in oil production was primarily a result of our ongoing development activities in the Eagle Ford shale, as well as better-than-expected initial production contributions from newly drilled wells in the Permian Basin. The decrease in oil revenues resulted from a lower oil price realized in the first quarter of 2015 of $43.37 per Bbl as compared to $96.34 per Bbl realized for the first quarter of 2014. This decrease in realized oil price was partially offset by the increase in our oil production of 53% in the first quarter of 2015, as compared to the first quarter of 2014. Our natural gas revenues increased by $3.5 million, or 23%, to $18.7 million for the three months ended March 31, 2015, as compared to $15.3 million for the three months ended March 31, 2014. The increase in natural gas revenues resulted from an increase in natural gas production of 170% to 6.6 Bcf for the three months ended March 31, 2015, as compared to 2.5 Bcf for the three months ended March 31, 2014, which was offset by a lower weighted average natural gas price of $2.82 per Mcf realized during the first quarter of 2015, as compared to a weighted average natural gas price of $6.20 per Mcf realized during the first quarter of 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 Matador's Elm Grove properties in Northwest

Louisiana during the latter half of 2014 and into 2015, but also includes increased natural gas production associated with Matador's operations in the Permian Basin, particularly in the Wolf Prospect area.

Realized gain (loss) on derivatives. Our realized gain on derivatives was $18.5 million for the three months ended March 31, 2015, as compared to a realized loss of $1.8 million for the three months ended March 31, 2014. For the three months ended March 31, 2015, we realized a net gain of $14.4 million, $3.6 million and $0.5 million attributable to our oil, natural gas and natural gas liquids ("NGL") derivative contracts, respectively. For the three months ended March 31, 2014, we realized a net loss of $0.9 million, $0.6 million and $0.3 million attributable to our oil, natural gas and NGL derivative contracts, respectively. The realized gain on our oil, natural gas and NGL derivative contracts between the respective periods was attributable to lower commodity prices for the three months ended March 31, 2015, as compared to the three months ended March 31, 2014. The realized gain on our oil and natural gas derivative contracts during the three months ended March 31, 2015 resulted from oil prices that were lower than the floor prices 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 on our NGL derivative contracts during the three months ended March 31, 2015 resulted from NGL prices that were lower than the fixed prices of our NGL swap contracts. We realized a gain of approximately $34.36 per Bbl and $0.77 per MMBtu hedged on all of our oil and natural gas derivative contracts, respectively, during the three months ended March 31, 2015, as compared to a loss of $1.49 per Bbl and $0.22 per MMBtu hedged on all of our oil and natural gas derivative contracts, respectively, during the three months ended March 31, 2014. The average floor prices of our oil costless collar contracts were $83.00 per Bbl and $87.73 per Bbl as of March 31, 2015 and March 31, 2014, respectively. The average ceiling prices of our oil costless collar contracts were $99.75 per Bbl and $99.76 per Bbl as of March 31, 2015 and March 31, 2014, respectively. During the first quarter of 2015, our natural gas costless collar contracts had average floor and ceiling prices of $3.73 per MMBtu and $4.65 per MMBtu, respectively, as compared to $3.42 per MMBtu and $4.98 per MMBtu, respectively, during the first quarter of 2014. The realized loss on derivatives on our oil, natural gas and NGL derivatives contracts during the three months ended March 31, 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 March 31, 2015 were 34% lower and 72% 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 $8.6 million for the three months ended March 31, 2015, as compared to an unrealized loss of $3.1 million for the three months ended March 31, 2014. During the period from December 31, 2014 to March 31, 2015, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts decreased from $55.5 million to $47.0 million, resulting in an unrealized loss on derivatives of $8.6 million for the three months ended March 31, 2015. The net fair value of our open oil derivative contracts decreased $6.5 million at March 31, 2015, as compared to December 31, 2014, primarily due to the realized revenue from oil derivative contracts settled during the three months ended March 31, 2015, partially offset by lower oil futures prices at March 31, 2015. The net fair value of our open natural gas derivative contracts decreased $1.6 million at March 31, 2015, as compared to December 31, 2014, primarily due to the realized revenue from natural gas derivative contracts settled during the three months ended March 31, 2015, partially offset by a decrease in natural gas futures prices during this period. The net fair value of our open NGL derivative contracts decreased $0.5 million at March 31, 2015, as compared to December 31, 2014, primarily due to the realized revenue from contracts settled during the three months ended March 31, 2015. During the period from December 31, 2013 to March 31, 2014, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts decreased from $(2.8) million to $(5.9) million due to increases in futures prices for these commodities, resulting in an unrealized loss on derivatives of $3.1 million for the three months ended March 31, 2014.

Table of Contents

Expenses

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

	Three Months Ended March 31,	
	2015	2014
(In thousands, except expenses per BOE)	(Unaudited)	(Unaudited)
Expenses:		
Production taxes and marketing	$7,049	$ 6,006
Lease operating	13,046	9,351
Depletion, depreciation and amortization	46,470	24,030
Accretion of asset retirement obligations	112	117
Full-cost ceiling impairment	67,127	—
General and administrative	13,413	7,219
Total expenses	147,217	46,723
Operating (loss) income	(74,805)	27,257
Other income (expense):		
Net loss on asset sales and inventory impairment	(97)	—
Interest expense	(2,070)	(1,396)
Interest and other income	384	38
Total other expense	(1,783)	(1,358)
(Loss) income before income taxes	(76,588)	25,899
Total income tax (benefit) provision	(26,390)	9,536
Net income attributable to non-controlling interest in subsidiary	(36)	—
Net (loss) income attributable to Matador Resources Company shareholders	$(50,234)	$ 16,363
Expenses per BOE:		
Production taxes and marketing	$3.33	$ 5.61
Lease operating	$6.16	$ 8.73
Depletion, depreciation and amortization	$21.96	$ 22.43
General and administrative	$6.34	$ 6.74

Three Months Ended March 31, 2015 as Compared to Three Months Ended March 31, 2014

Production taxes and marketing. Our production taxes and marketing expenses increased by $1.0 million to $7.0 million, or an increase of 17%, for the three months ended March 31, 2015, as compared to $6.0 million for the three months ended March 31, 2014. On a unit-of-production basis, however, our production taxes and marketing expenses decreased by 41% to $3.33 per BOE for the three months ended March 31, 2015, as compared to $5.61 per BOE for the three months ended March 31, 2014. The increase in production taxes and marketing expenses on an absolute basis was primarily attributable to higher natural gas marketing expenses of $4.4 million for the three months ended March 31, 2015, as compared to natural gas marketing expenses of $2.1 million for the three months ended March 31, 2014, an increase of $2.3 million, due to the 170% increase in natural gas production to 6.6 Bcf during the three months ended March 31, 2015, as compared to 2.5 Bcf of natural gas production for the three months ended March 31, 2014. Our production taxes, however, decreased for the three months ended March 31, 2015 by $1.2 million to $2.7 million, as compared to $3.9 million for the three months ended March 31, 2014, primarily due to the 31% decrease in oil revenues in the first quarter of 2015 as compared to the first quarter of 2014.

Lease operating expenses. Our lease operating expenses increased by $3.7 million to $13.0 million, or an increase of 40%, for the three months ended March 31, 2015, as compared to $9.4 million for the three months ended March 31, 2014. Our lease operating expenses per unit of production decreased 29% to $6.16 per BOE for the three months ended March 31, 2015, as compared to $8.73 per BOE for the three months ended March 31, 2014. Our total oil and natural gas production increased 98% to approximately 2.1 million BOE for the three months ended March 31, 2015 from approximately 1.1 million BOE for the three months ended March 31, 2014, including an increase of 53% in oil production to over 1.0 million Bbl for the three months ended March 31, 2015, as compared to 661,000 Bbl for the three months ended March 31, 2014, which would typically result in higher lease operating expenses. Oil production was 48% of total production by volume for the three months ended March 31, 2015, as compared to 62% of total production by volume for the three months ended March 31, 2014. The decrease achieved in lease operating expenses on a unit-of-production basis, was attributable to several key factors, including (i) the installation of permanent production facilities on almost all of our Eagle Ford properties, alleviating the need for the extended

Table of Contents

use of flowback equipment to produce newly completed Eagle Ford wells, (ii) fewer cleanout operations on producing wells as a result of fracturing operations on newly drilled Eagle Ford wells, (iii) a decrease in salt water disposal costs on a per barrel basis particularly in the Permian Basin, (iv) reduced service costs beginning to impact lease operating expenses and (v) 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 begun to significantly impact our water disposal costs in the Wolf prospect area.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $22.4 million to $46.5 million, or an increase of 93%, for the three months ended March 31, 2015, as compared to the three months ended March 31, 2014. On a unit-of-production basis, our depletion, depreciation and amortization expenses decreased to $21.96 per BOE for the three months ended March 31, 2015, or a decrease of 2%, from $22.43 per BOE for the three months ended March 31, 2014. The increase in the total depletion, depreciation and amortization expenses was attributable to the increase in our oil and natural gas production of 98% to 2.1 million BOE from 1.1 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 45% to 79.3 million BOE at March 31, 2015 from 54.6 million BOE at March 31, 2014. This increase in total proved oil and natural gas reserves was primarily attributable to the continued development of our acreage in the Eagle Ford shale and the ongoing delineation and development of our acreage in the Permian Basin.

Full-cost ceiling impairment. At March 31, 2015, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost 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. This full-cost ceiling impairment of $67.1 million is reflected in our operating expenses for the three months ended March 31, 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 March 31, 2014.

General and administrative. Our general and administrative expenses increased by $6.2 million to $13.4 million, or an increase of 86%, for the three months ended March 31, 2015, as compared to $7.2 million for the three months ended March 31, 2014. The increase in our general and administrative expenses for the three months ended March 31, 2015 was largely attributable to increased payroll expenses associated with additional personnel joining the Company between the respective periods to support our increased land, geoscience, drilling, completion, production, accounting and administration functions, including the addition of 29 new employees in Roswell, New Mexico as a result of the HEYCO Merger. General and administrative expenses also included non-cash stock-based compensation expense of $2.3 million for the three months ended March 31, 2015, as compared to $1.8 million for the three months ended March 31, 2014, and $2.2 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. While our general and administrative expenses increased 86% on an absolute basis, our general and administrative expenses decreased by 6% on a unit-of-production basis to $6.34 per BOE for the three months ended March 31, 2015, as compared to $6.74 per BOE for the three months ended March 31, 2014, as a result of our increased oil equivalent production between the respective periods.

Interest expense. For the three months ended March 31, 2015, we incurred total interest expense of $3.0 million. We capitalized $1.0 million of our interest expense on certain qualifying projects for the three months ended March 31, 2015 and expensed the remaining $2.1 million to operations. For the three months ended March 31, 2014, we incurred total interest expense of $2.1 million. We capitalized $0.7 million of our interest expense on certain qualifying projects for the three months ended March 31, 2014 and expensed the remaining $1.4 million to operations. The increase in total interest expense is attributable to an increase in both the average outstanding borrowings and the average effective interest rate under our Credit Agreement between the comparable periods. At March 31, 2015, we had $410.0 million in borrowings and $0.6 million in letters of credit outstanding under our Credit Agreement. Due to the higher interest rate on the Notes, as compared 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 34.4% for the three months ended March 31, 2015. Total income tax benefit for the three months ended March 31, 2015 differed from amounts computed by applying the U.S. federal statutory tax rate to pre-tax loss due primarily to the impact of permanent differences between book and taxable income. The total income tax benefit of $26.4 million for the three months ended March 31, 2015 includes $24.3 million of deferred income tax benefit resulting from the full-cost ceiling impairment. At March 31, 2014, based on our projections for the remainder of 2014, we anticipated incurring a small AMT liability for the year ending December 31, 2014, the proportionate share of which was recorded as the current income tax provision of $1.3 million for the three months ended March 31, 2014. Our effective tax rate for the three months ended March 31, 2014 was 36.8%. Total income tax expense for the three months ended March 31, 2014 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily to the impact of permanent differences between book and taxable income.

Table of Contents

Liquidity and Capital Resources

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

At March 31, 2015, we had cash totaling $6.1 million, the borrowing base under our Credit Agreement was $450.0 million and we had $410.0 million of outstanding long-term borrowings and $0.6 million in outstanding letters of credit. During the three months ended March 31, 2015, the borrowings under our Credit Agreement bore interest at an effective interest rate of 2.9% per annum. On April 14, 2015, using a portion of the net proceeds from the Notes offering previously discussed, we repaid $380.0 million of our outstanding borrowings under the Credit Agreement. From April 14, 2015 through April 23, 2015, we borrowed $55.0 million under our Credit Agreement to finance a portion of our working capital requirements and capital expenditures and the acquisition of additional leasehold interests. On April 24, 2015, using a portion of the net proceeds from our April 2015 public offering of common stock previously discussed, we repaid the $85.0 million of outstanding borrowings under the Credit Agreement. At May 6, 2015, we had no borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement.

Our 2015 capital expenditure budget is estimated to be $350.0 million (excluding capital expenditures associated with the HEYCO Merger) and includes approximately $267.0 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. Due to the sharp decline in oil and natural gas prices since mid-2014, we have reduced our estimated capital expenditure budget by approximately 43% from the $610.4 million in capital expenditures we incurred in 2014. We were operating five drilling rigs, two rigs in the Eagle Ford and three rigs in the Permian Basin, at the beginning of 2015, but had reduced our operated drilling rigs to two by the end of the first quarter of 2015, with both operating in the Permian Basin. We are currently running two drilling rigs in the Permian Basin, one in Loving County, Texas and the other in Eddy County, New Mexico, and currently plan to operate at least two drilling rigs in the Permian Basin for the remainder of 2015. We are now considering adding a third drilling rig in the Permian Basin as early as late summer 2015 depending on commodity prices and improved well economics resulting from higher recoveries, realized savings from various operating efficiencies and cost savings from vendors. 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 in 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 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 May 6, 2015, we had approximately 80% of our anticipated oil production and approximately 70% of our anticipated natural gas production hedged for the remainder of 2015.

Table of Contents

Expenditures for the acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipate investing approximately $350.0 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	$ 267.0
Midstream activities	38.0
Pipeline and infrastructure expenditures	25.0
Leasehold acquisition and 2-D and 3-D seismic data	20.0
Total	$ 350.0

While we have budgeted $350.0 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 (assuming availability under our borrowing base), the net proceeds from the offering of the Notes described above and the offering of common stock described above, 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 cash flows for the three months ended March 31, 2015 and 2014 are presented below:

	Three Months Ended March 31,	
	2015	2014
(In thousands)	(Unaudited)	(Unaudited)
Net cash provided by operating activities	$ 93,346	$ 31,945
Net cash used in investing activities	(166,092)	(93,898)
Net cash provided by financing activities	70,400	70,006
Net change in cash	$ (2,346)	$ 8,053
Adjusted EBITDA[1]	$ 50,146	$ 56,345

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

Cash Flows Provided by Operating Activities

Net cash provided by operating activities increased by $61.4 million to $93.3 million for the three months ended March 31, 2015, as compared to net cash provided by operating activities of $31.9 million for the three months ended March 31, 2014. Excluding changes in operating assets and liabilities, net cash provided by operating activities decreased by $5.6 million to $48.1 million for the three months ended March 31, 2015 from $53.7 million for the three months ended March 31, 2014. This decrease is primarily attributable to the 21% decrease in our oil and natural gas revenues between the respective periods. Changes in our operating assets and liabilities between March 31, 2014 and March 31, 2015 resulted in a net increase of $67.0 million in net cash provided by operating activities for the three months ended March 31, 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

Table of Contents

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 $72.2 million to $166.1 million for the three months ended March 31, 2015 from $93.9 million for the three months ended March 31, 2014. This increase in net cash used in investing activities is primarily attributable to the increase in cash used for oil and natural gas properties capital expenditures for the three months ended March 31, 2015, as compared to the three months ended March 31, 2014, but also includes capital expenditures associated with the HEYCO Merger. Cash used for oil and natural gas properties capital expenditures for the three months ended March 31, 2015 was primarily attributable to our operated drilling and completion activities in the Eagle Ford shale play and the Permian Basin. A small portion of our capital expenditures for the three months ended March 31, 2015 was directed to our participation in non-operated wells, primarily in the Haynesville shale.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities increased by $0.4 million to $70.4 million for the three months ended March 31, 2015 from $70.0 million for the three months ended March 31, 2014. The net cash provided by financing activities for the three months ended March 31, 2015 and 2014 was primarily attributable to the incremental borrowings under our Credit Agreement of $70.0 million during the respective periods.

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.

Table of Contents

The following table presents our calculation of Adjusted EBITDA and the reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

	Three Months Ended March 31,	
(In thousands)	2015	2014
Unaudited Adjusted EBITDA Reconciliation to Net (Loss) Income:		
Net (loss) income attributable to Matador Resources Company shareholders	$(50,234)	$16,363
Interest expense	2,070	1,396
Total income tax (benefit) provision	(26,390)	9,536
Depletion, depreciation and amortization	46,470	24,030
Accretion of asset retirement obligations	112	117
Full-cost ceiling impairment	67,127	—
Unrealized loss on derivatives	8,557	3,108
Stock-based compensation expense	2,337	1,795
Net loss on asset sales and inventory impairment	97	—
Adjusted EBITDA	$50,146	$56,345

	Three Months Ended March 31,	
(In thousands)	2015	2014
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:		
Net cash provided by operating activities	$93,346	$31,945
Net change in operating assets and liabilities	(45,234)	21,729
Interest expense	2,070	1,396
Current income tax provision	—	1,275
Net income attributable to non-controlling interest in subsidiary	(36)	—
Adjusted EBITDA	$50,146	$56,345

Our Adjusted EBITDA decreased by $6.2 million to $50.1 million, or a decrease of 11%, for the three months ended March 31, 2015, as compared to $56.3 million for the three months ended March 31, 2014. This decrease in our Adjusted EBITDA is primarily attributable to the decrease in our oil and natural gas revenues for the three months ended March 31, 2015 as compared to the three months ended March 31, 2014.

Credit Agreement

On September 28, 2012, we entered into the Credit Agreement, which increased the maximum facility amount from $400.0 million to $500.0 million. The Credit Agreement matures December 29, 2016. MRC Energy Company is the borrower under the Credit Agreement and is a subsidiary of Matador that, at March 31, 2015, directly or indirectly owns the ownership interests in Matador's other operating subsidiaries other than one less-than-wholly-owned subsidiary and MRC Delaware Resources, LLC. Borrowings are secured by mortgages on substantially all of our proved oil and natural gas properties and by the equity interests of certain of MRC Energy Company's wholly-owned subsidiaries, which are also guarantors. In addition, all obligations under the Credit Agreement are guaranteed by Matador. Various commodity hedging agreements with certain of the lenders under the Credit Agreement (or affiliates thereof) are also secured by the collateral of and guaranteed by certain eligible subsidiaries of MRC Energy Company. The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of our proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. Both we and the lenders may request an unscheduled redetermination of the borrowing base once each between scheduled redetermination dates. During the 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, we 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 entered into concurrently with the offering of the Notes on April 14, 2015, the borrowing base was reduced to the conforming borrowing base of $375.0 million.

Table of Contents

In the event of a borrowing base increase, we are required to pay a fee to the lenders equal to a percentage of the amount of the increase, which is determined based on market conditions at the time of the borrowing base increase. If, upon a redetermination or the automatic reduction of the borrowing base to the conforming borrowing base, the borrowing base were to be less than the outstanding borrowings under the Credit Agreement at any time, we would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or to repay the deficit in equal installments over a period of six months. At March 31, 2015, we had $410.0 million in borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. For the three months ended March 31, 2015, our outstanding borrowings bore interest at an effective interest rate of approximately 2.9% per annum. On April 14, 2015, using a portion of the net proceeds from the offering of the Notes discussed herein, we repaid $380.0 million of our outstanding borrowings under the Credit Agreement. From April 14, 2015 through April 23, 2015, we borrowed $55.0 million under the Credit Agreement to finance a portion of our working capital requirements and capital expenditures and the acquisition of additional leasehold interests. On April 24, 2015, using a portion of the net proceeds from the April 2015 public offering of common stock discussed herein, we repaid the $85.0 million of outstanding borrowings under the Credit Agreement. At May 6, 2015, we had no borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. We expect to access future borrowings under our Credit Agreement to fund our remaining 2015 capital expenditure requirements, if needed, in excess of cash on hand and amounts available from our operating cash flows.

As of March 31, 2015, if we borrow funds as a base rate loan, such borrowings will bear interest at a rate equal to the higher of (i) the prime rate for such day, (ii) the Federal Funds Effective Rate (as defined in the Credit Agreement) on such day, plus 0.50% or (iii) the daily adjusting LIBOR rate (as defined in the Credit Agreement) plus 1.0% plus, in each case, an amount from 0.50% to 2.75% of such outstanding loan depending on the level of borrowings under the agreement. If we borrow funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (i) the quotient obtained by dividing (A) the LIBOR rate by (B) a percentage equal to 100% minus the maximum rate during such interest calculation period at which Royal Bank of Canada ("RBC") is required to maintain reserves on Eurocurrency Liabilities (as defined in Regulation D of the Board of Governors of the Federal Reserve System) plus (ii) an amount from 1.50% to 3.75% of such outstanding loan depending on the level of borrowings under the Credit Agreement. The interest period for Eurodollar borrowings may be one, two, three or six months as designated by us. A commitment fee of 0.375% to 0.50%, depending on the unused availability under the Credit Agreement, is also paid quarterly in arrears. We include this commitment fee, any amortization of deferred financing costs (including origination, borrowing base increase and amendment fees) and annual agency fees, if any, as interest expense and in our interest rate calculations and related disclosures. The Credit Agreement requires us to maintain a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.25 or less.

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

- incur indebtedness or grant liens on any of our assets;
- enter into commodity hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates;
- engage in certain asset dispositions, including a sale of all or substantially all of our assets; and
- take certain actions with respect to the 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 us or our subsidiaries; and
- a change of control, as defined in the Credit Agreement.

Table of Contents

At March 31, 2015, we believe that we were in compliance with the terms of the Credit Agreement.

Senior Unsecured Notes

On April 14, 2015, we issued $400.0 million of 6.875% senior notes due 2023. The Notes are our senior unsecured obligations, are redeemable as described below and were issued at par value. The net proceeds of approximately $392.0 million, after deducting the initial purchasers' discounts and estimated offering expenses, were used to pay down a portion of the outstanding borrowings under our 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 our wholly-owned subsidiaries.

On or after April 15, 2018, we 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, we 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 us and our 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, we 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 our 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 our 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 our Restricted Subsidiaries (as defined in the Indenture) to us;
- consolidate, merge or transfer all or substantially all of our 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 us, 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 without

40

Table of Contents

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 us 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 our failure to comply with the covenant relating to merger, consolidation or sale of assets;
- failure by us for 180 days after notice to comply with its reporting obligations under the Indenture;
- failure by us 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 us and our Restricted Subsidiaries in the aggregate principal amount of $25.0 million or more;
- failure by us 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 us or any Restricted Subsidiary that is a Significant Subsidiary or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary.

Current Note Payable

In connection with the HEYCO Merger, we 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 of our associated obligations were terminated.

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 March 31, 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 consolidated financial statements in this Quarterly Report on Form 10-Q for more information regarding our off-balance sheet arrangements. Such information is incorporated herein by reference.

Table of Contents

Obligations and Commitments

We had the following material contractual obligations and commitments at March 31, 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)	$410,571	$571	$410,000	$—	$—
Current note payable (2)	11,982	11,982	—	—	—
Office lease	6,869	1,015	1,801	1,869	2,184
Non-operated drilling commitments(3)	18,607	18,607	—	—	—
Drilling rig contracts(4)	44,958	24,566	20,392	—	—
Asset retirement obligations	13,543	268	1,247	2,825	9,203
Gas processing and transportation agreement(5)	5,250	2,702	2,548	—	—
Gas plant engineering, procurement, construction and installation agreement (6)	9,770	9,770	—	—	—
Total contractual cash obligations	$521,550	$69,481	$435,988	$4,694	$11,387

---

(1) At March 31, 2015, we had $410.0 million in revolving borrowings outstanding under our Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. The revolving borrowings are scheduled to mature in December 2016. These amounts do not include estimated interest on the obligations because our revolving borrowings have short-term interest periods, and we are unable to determine what our borrowing costs may be in future periods. On April 14, 2015, using a portion of the net proceeds from the offering of the Notes discussed herein, we repaid $380.0 million of our outstanding borrowings under the Credit Agreement. From April 14, 2015 through April 23, 2015, we borrowed $55.0 million under the Credit Agreement to finance a portion of our working capital requirements and capital expenditures and the acquisition of additional leasehold interests. On April 24, 2015, using a portion of the net proceeds from our April 2015 public offering of common stock, we repaid the $85.0 million of outstanding borrowings under our Credit Agreement.

(2) In connection with the HEYCO Merger, we 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 our Notes offering, and the related credit agreement and all of our associated obligations were terminated.

(3) At March 31, 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 March 31, 2015. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of $18.6 million at March 31, 2015, which we expect to incur within the next few months.

(4) 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 $45.0 million at March 31, 2015.

(5) 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 $5.3 million at March 31, 2015.

(6) 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 three months ended March 31, 2015, oil prices ranged from a high of approximately $53.53 per Bbl in mid-February to a low of approximately $43.46 per Bbl in mid-March, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. We realized an average oil price of $43.37 per Bbl ($57.68 per Bbl including realized gains from oil derivatives) for our oil production for the three months ended March 31, 2015, as compared to $96.34 per Bbl ($94.91 per Bbl including realized losses from oil derivatives) for the three months ended March 31, 2014. Subsequent to March 31, 2015, oil prices have increased and at May 6, 2015, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date closed at $60.93 per Bbl as compared to $99.50 per Bbl at May 6, 2014.

Table of Contents

For the three months ended March 31, 2015, natural gas prices ranged from a high of $3.23 per MMBtu in mid-January, to a low of $2.58 per MMBtu in early February, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. We realized a weighted average natural gas price of $2.82 per Mcf ($3.43 per Mcf including aggregate realized gains from natural gas and NGL derivatives) for our natural gas production for the three months ended March 31, 2015, as compared to $6.20 per Mcf ($5.83 per Mcf including aggregate realized losses from natural gas and NGL derivatives) for the three months ended March 31, 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 mid-February, natural gas prices have increased somewhat, and at May 6, 2015, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date closed at $2.78 per MMBtu, as compared to $4.80 per MMBtu at May 6, 2014.

In response to the sharp decrease in oil and natural gas prices experienced in late 2014 and early 2015, we reduced our 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. This 2015 capital expenditure budget reflects the reduction of our drilling program from five drilling rigs operating in January 2015 to two drilling rigs at the end of the first quarter of 2015. We are currently running two drilling rigs in the Permian Basin, one in Loving County, Texas and the other in Eddy County, New Mexico, and currently plan to operate at least two drilling rigs in the Permian for the remainder of 2015. We are now considering adding a third drilling rig in the Permian Basin as early as late summer 2015 depending on commodity prices and improved well economics resulting from higher recoveries, realized savings from various operating efficiencies and cost savings from vendors. 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 also plan to direct a small portion of our 2015 capital expenditures, about 4%, to our participation in non-operated Haynesville shale wells in Northwest Louisiana.

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.

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

Table of Contents

arrangements are initially “costless” to us. In the case of a costless collar, the put option and the call option have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over a specified time, providing downside price protection.

We record all derivative financial instruments at fair value. The fair value of our derivative financial instruments is determined using industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. At March 31, 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 March 31, 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 March 31, 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 March 31, 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.

Table of Contents

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.

Table of Contents

SIGNATURES

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

		MATADOR RESOURCES COMPANY
Date: May 11, 2015	By:	/s/ Joseph Wm. Foran Joseph Wm. Foran Chairman and Chief Executive Officer
Date: May 11, 2015	By:	/s/ David E. Lancaster David E. Lancaster Executive Vice President, Chief Operating Officer and Chief Financial Officer

Table of Contents

EXHIBIT INDEX

Exhibit Number	Description
2.1	Amendment No. 5 to Agreement and Plan of Merger, dated as of April 15, 2015, by and among HEYCO Energy Group, Inc., Matador Resources Company and MRC Delaware Resources, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on April 15, 2015).
3.1	Amended and Restated Certificate of Formation of Matador Resources Company (filed herewith).
3.2	Certificate of Amendment to the Amended and Restated Certificate of Formation of Matador Resources Company (filed herewith).
4.1	Indenture, dated as of April 14, 2015, by and among Matador Resources Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on April 14, 2015).
4.2	Registration Rights Agreement, dated as of April 14, 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 4.2 to the Current Report on Form 8-K filed on April 14, 2015).
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).
23.1	Consent of Netherland, Sewell & Associates, Inc. (filed herewith).
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99.1	Audit report of Netherland, Sewell & Associates, Inc. (filed herewith).

101

The following financial information from Matador Resources Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 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).