Matador Resources Co
Form 10-Q
November 04, 2016
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2016

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 | 27-4662601 |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| 5400 LBJ Freeway, Suite 1500 Dallas, Texas | 75240 |
| (Address of principal executive offices) | (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 November 1, 2016, there were 93,469,313 shares of the registrant’s common stock, par value $0.01 per share, outstanding.

MATADOR RESOURCES COMPANY
FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2016
INDEX

Table of Contents

Part I – FINANCIAL INFORMATION
Item 1. Financial Statements — Unaudited

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

Table of Contents

Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED BALANCE SHEETS - UNAUDITED
(In thousands, except par value and share data)

| | September 30, 2016 | December 31, 2015 |
|---|---|---|
| ASSETS | | |
| Current assets | | |
| Cash | $ 20,566 | $ 16,732 |
| Restricted cash | 1,803 | 44,357 |
| Accounts receivable | | |
| Oil and natural gas revenues | 27,739 | 16,616 |
| Joint interest billings | 18,796 | 16,999 |
| Other | 5,657 | 10,794 |
| Derivative instruments | — | 16,284 |
| Lease and well equipment inventory | 3,182 | 2,022 |
| Prepaid expenses | 3,277 | 3,203 |
| Total current assets | 81,020 | 127,007 |
| Property and equipment, at cost | | |
| Oil and natural gas properties, full-cost method | | |
| Evaluated | 2,341,342 | 2,122,174 |
| Unproved and unevaluated | 445,421 | 387,504 |
| Other property and equipment | 141,420 | 86,387 |
| Less accumulated depletion, depreciation and amortization | (1,832,478 ) | (1,583,659 ) |
| Net property and equipment | 1,095,705 | 1,012,406 |
| Other assets | 968 | 1,448 |
| Total assets | $ 1,177,693 | $ 1,140,861 |
| LIABILITIES AND SHAREHOLDERS’ EQUITY | | |
| Current liabilities | | |
| Accounts payable | $ 4,534 | $ 10,966 |
| Accrued liabilities | 93,339 | 92,369 |
| Royalties payable | 21,717 | 16,493 |
| Amounts due to affiliates | 7,033 | 5,670 |
| Derivative instruments | 10,139 | — |
| Advances from joint interest owners | 3,847 | 700 |
| Deferred gain on plant sale | 6,440 | 4,830 |
| Amounts due to joint ventures | 4,050 | 2,793 |
| Income taxes payable | — | 2,848 |
| Other current liabilities | 530 | 161 |
| Total current liabilities | 151,629 | 136,830 |
| Long-term liabilities | | |
| Borrowings under Credit Agreement | 65,000 | — |
| Senior unsecured notes payable | 392,153 | 391,254 |
| Asset retirement obligations | 19,452 | 15,166 |
| Amounts due to joint ventures | 2,700 | 3,956 |
| Derivative instruments | 3,838 | — |
| Deferred gain on plant sale | 97,676 | 102,506 |
| Other long-term liabilities | 7,451 | 2,190 |
| Total long-term liabilities | 588,270 | 515,072 |
| Commitments and contingencies (Note 10) | | |

| | | |
|---|---|---|
| Shareholders’ equity | | |
| Common stock - $0.01 par value, 120,000,000 shares authorized; 93,580,969 and 85,567,021 shares issued; and 93,464,898 and 85,564,435 shares outstanding, respectively | 936 | 856 |
| Additional paid-in capital | 1,176,198 | 1,026,077 |
| Retained deficit | (740,505) | (538,930) |
| Total Matador Resources Company shareholders’ equity | 436,629 | 488,003 |
| Non-controlling interest in subsidiaries | 1,165 | 956 |
| Total shareholders’ equity | 437,794 | 488,959 |
| Total liabilities and shareholders’ equity | $ 1,177,693 | $ 1,140,861 |

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

Table of Contents

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Revenues | | | | |
| Oil and natural gas revenues | $83,079 | $71,815 | $196,341 | $222,128 |
| Third-party midstream services revenues | 1,566 | 569 | 2,956 | 1,384 |
| Realized gain on derivatives | 885 | 19,862 | 10,413 | 52,146 |
| Unrealized gain (loss) on derivatives | 3,203 | 6,733 | (30,261) | (25,356) |
| Total revenues | 88,733 | 98,979 | 179,449 | 250,302 |
| Expenses | | | | |
| Production taxes, transportation and processing | 12,388 | 9,426 | 30,846 | 26,734 |
| Lease operating | 14,605 | 13,466 | 41,300 | 40,140 |
| Plant and other midstream services operating | 1,449 | 1,450 | 3,537 | 2,772 |
| Depletion, depreciation and amortization | 30,015 | 45,237 | 90,185 | 143,477 |
| Accretion of asset retirement obligations | 276 | 182 | 828 | 427 |
| Full-cost ceiling impairment | — | 285,721 | 158,633 | 581,874 |
| General and administrative | 13,146 | 12,151 | 39,506 | 38,523 |
| Total expenses | 71,879 | 367,633 | 364,835 | 833,947 |
| Operating income (loss) | 16,854 | (268,654) | (185,386) | (583,645) |
| Other income (expense) | | | | |
| Net gain (loss) on asset sales and inventory impairment | 1,073 | — | 3,140 | (97) |
| Interest expense | (6,880) | (7,229) | (20,244) | (15,168) |
| Other (expense) income | (141) | 564 | (17) | 637 |
| Total other expense | (5,948) | (6,665) | (17,121) | (14,628) |
| Income (loss) before income taxes | 10,906 | (275,319) | (202,507) | (598,273) |
| Income tax (benefit) provision | | | | |
| Current | (1,141) | (295) | (1,141) | (295) |
| Deferred | — | (33,010) | — | (148,750) |
| Total income tax benefit | (1,141) | (33,305) | (1,141) | (149,045) |
| Net income (loss) | 12,047 | (242,014) | (201,366) | (449,228) |
| Net income attributable to non-controlling interest in subsidiaries | (116) | (45) | (209) | (156) |
| Net income (loss) attributable to Matador Resources Company shareholders | $11,931 | $(242,059) | $(201,575) | $(449,384) |
| Earnings (loss) per common share | | | | |
| Basic | $0.13 | $(2.86) | $(2.24) | $(5.58) |
| Diluted | $0.13 | $(2.86) | $(2.24) | $(5.58) |
| Weighted average common shares outstanding | | | | |
| Basic | 93,384 | 84,685 | 90,016 | 80,481 |
| Diluted | 93,724 | 84,685 | 90,016 | 80,481 |

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 Nine Months Ended September 30, 2016

| | Common Stock Shares | Amount | Additional paid-in capital | Retained deficit | Treasury Stock Shares | Amount | Total shareholders' equity attributable to Matador Resources Company | Non-controlling interest in subsidiary | Total shareholders' equity |
|---|---|---|---|---|---|---|---|---|---|
| Balance at January 1, 2016 | 85,567 | $ 856 | $ 1,026,077 | $ (538,930) | 2 | $ — | $ 488,003 | $ 956 | $ 488,959 |
| Issuance of common stock | 7,500 | 75 | 142,275 | — | — | — | 142,350 | — | 142,350 |
| Cost to issue equity | — | — | (830) | — | — | — | (830) | — | (830) |
| Stock-based compensation expense related to equity-based awards | — | — | 8,681 | — | — | — | 8,681 | — | 8,681 |
| Stock options exercised, net of options forfeited in net share settlements | 18 | — | — | — | — | — | — | — | — |
| Restricted stock issued | 465 | 5 | (5) | — | — | — | — | — | — |
| Restricted stock forfeited | — | — | — | — | 114 | — | — | — | — |
| Vesting of restricted stock units | 31 | — | — | — | — | — | — | — | — |
| Current period net loss | — | — | — | (201,575) | — | — | (201,575) | 209 | (201,366) |
| Balance at September 30, 2016 | 93,581 | $ 936 | $ 1,176,198 | $ (740,505) | 116 | $ — | $ 436,629 | $ 1,165 | $ 437,794 |

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

Table of Contents

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

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2016 | 2015 |
| Operating activities | | |
| Net loss | $(201,366) | $(449,228) |
| Adjustments to reconcile net loss to net cash provided by operating activities | | |
| Unrealized loss on derivatives | 30,261 | 25,356 |
| Depletion, depreciation and amortization | 90,185 | 143,477 |
| Accretion of asset retirement obligations | 828 | 427 |
| Full-cost ceiling impairment | 158,633 | 581,874 |
| Stock-based compensation expense | 9,138 | 6,886 |
| Deferred income tax benefit | — | (148,750) |
| Amortization of debt issuance cost | 899 | 551 |
| Net (gain) loss on asset sales and inventory impairment | (3,140) | 97 |
| Changes in operating assets and liabilities | | |
| Accounts receivable | (7,782) | 1,997 |
| Lease and well equipment inventory | (669) | (225) |
| Prepaid expenses | (74) | (329) |
| Other assets | 480 | 665 |
| Accounts payable, accrued liabilities and other current liabilities | 9,710 | 16,863 |
| Royalties payable | 5,225 | 6,898 |
| Advances from joint interest owners | 3,147 | 306 |
| Income taxes payable | (2,848) | (444) |
| Other long-term liabilities | 3,835 | (497) |
| Net cash provided by operating activities | 96,462 | 185,924 |
| Investing activities | | |
| Oil and natural gas properties capital expenditures | (288,175) | (334,951) |
| Expenditures for other property and equipment | (57,148) | (46,738) |
| Proceeds from sale of assets | 5,173 | — |
| Business combination, net of cash acquired | — | (24,028) |
| Restricted cash | 43,098 | — |
| Restricted cash in less-than-wholly-owned subsidiaries | (544) | 158 |
| Net cash used in investing activities | (297,596) | (405,559) |
| Financing activities | | |
| Repayments of borrowings | — | (476,982) |
| Borrowings under Credit Agreement | 65,000 | 125,000 |
| Proceeds from issuance of senior unsecured notes | — | 400,000 |
| Cost to issue senior unsecured notes | — | (9,479) |
| Proceeds from issuance of common stock | 142,350 | 188,720 |
| Cost to issue equity | (830) | (1,151) |
| Proceeds from stock options exercised | — | 10 |
| Capital commitments from non-controlling interest owners in less-than-wholly-owned subsidiaries | — | 562 |
| Taxes paid related to net share settlement of stock-based compensation | (1,552) | (1,565) |
| Net cash provided by financing activities | 204,968 | 225,115 |
| Increase in cash | 3,834 | 5,480 |

| | | |
|---|---|---|
| Cash at beginning of period | 16,732 | 8,407 |
| Cash at end of period | $20,566 | $13,887 |

Supplemental disclosures of cash flow information (Note 11)

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

7

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 Delaware Basin in Southeast New Mexico and West Texas. The Company also operates in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. Additionally, the Company conducts midstream operations in support of its exploration, development and production operations and provides natural gas processing, natural gas, oil and salt water gathering services and salt water disposal services to third parties on a limited basis.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Interim Financial Statements, Basis of Presentation, Consolidation and Significant Estimates

The interim unaudited condensed consolidated financial statements of Matador and its subsidiaries have been prepared in accordance with the rules and regulations of the Securities and Exchange Commission (“SEC”) but do not include all of the information and footnotes required by generally accepted accounting principles in the United States of America (“U.S. GAAP”) for complete financial statements and should be read in conjunction with the Company’s audited consolidated financial statements and notes thereto included in the Company’s Annual Report on Form 10-K for the year ended December 31, 2015 (the “Annual Report”) filed with the SEC. The Company consolidates certain subsidiaries that are less-than-wholly-owned and the net income and equity attributable to the non-controlling interest in these subsidiaries have been reported separately as required by Accounting Standards Codification (“ASC”) 810. The Company proportionately consolidates certain joint ventures that are less-than-wholly-owned and are involved in oil and natural gas exploration. All intercompany accounts and transactions have been eliminated in consolidation. In management’s opinion, these interim unaudited condensed consolidated financial statements include all adjustments, consisting only of normal, recurring adjustments, which are necessary for a fair presentation of the Company’s interim unaudited condensed consolidated financial statements as of September 30, 2016. Amounts as of December 31, 2015 are derived from the Company’s audited consolidated financial statements in the Annual Report.

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

Reclassifications

Certain reclassifications have been made to the prior periods’ financial statements to conform to the current period presentation. As a result of the growth of the Company’s midstream operations, these operations met the required threshold for segment reporting at September 30, 2016. As a result, $0.5 million and $1.3 million for the three and nine months ended September 30, 2015, respectively, were reclassified from other income to third-party midstream services revenues and $0.1 million for both the three and nine months ended September 30, 2015 was reclassified from production taxes, transportation and processing expenses to third-party midstream services revenues. In addition, $1.5 million and $2.8 million related to midstream operating costs for the three and nine months ended September 30, 2015, respectively, were reclassified from lease operating expenses to plant and other midstream services operating expenses. These reclassifications had no effect on previously reported results of operations, cash flows or retained earnings.

Change in Accounting Principle

During the second quarter of 2016, the Company adopted Accounting Standards Update (“ASU”) 2016-09, Compensation - Stock Compensation (Topic 718), which simplifies several aspects of the accounting for employee share-based payment transactions, including accounting for income tax, forfeitures, statutory tax withholding requirements, classifications of awards as either equity or liability and classification of taxes in the statement of cash flows, requiring either retrospective, modified retrospective or prospective transition. The amended guidance also requires an entity to record excess tax benefits and

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

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

deficiencies in the income statement. The adoption of this ASU had no impact on any period presented for (i) the Company's financial position or statements of operations, as the Company currently has a valuation allowance against its net deferred tax assets, or (ii) the Company's statements of cash flows, as the Company has historically accounted for taxes paid for net share settlement as a financing activity as required under this ASU. In addition, the Company uses historical forfeiture rates to estimate future forfeitures attributable to the service-based vesting requirements not being met and has continued to do so upon adoption of this ASU.

Property and Equipment

The Company uses the full-cost method of accounting for its investments in oil and natural gas properties. Under this method, the Company is required to perform a ceiling test each quarter which determines a limit, or ceiling, on the capitalized costs of oil and natural gas properties based primarily on the after-tax estimated future net cash flows from oil and natural gas properties using a 10% discount rate and the arithmetic average of first-day-of-the-month oil and natural gas prices for the prior 12-month period. For the three months ended September 30, 2016, the cost center ceiling was higher than the capitalized costs of oil and natural gas properties, thus no impairment charge was necessary; however, due primarily to declines in oil and natural gas prices in recent periods, the capitalized costs of oil and natural gas properties exceeded the cost center ceiling for the first two quarters of 2016 and all of 2015, and as a result, the Company recorded impairment charges to its net capitalized costs in its unaudited condensed consolidated statements of operations of $285.7 million for the three months ended September 30, 2015, and $158.6 million and $581.9 million for the nine months ended September 30, 2016 and 2015, respectively.

The Company capitalized approximately $4.3 million and $1.4 million of its general and administrative costs for the three months ended September 30, 2016 and 2015, respectively, and approximately $0.7 million and $0.5 million of its interest expense for the three months ended September 30, 2016 and 2015, respectively. The Company capitalized approximately $10.3 million and $4.9 million of its general and administrative costs for the nine months ended September 30, 2016 and 2015, respectively, and approximately $2.9 million of its interest expense for each of the nine months ended September 30, 2016 and 2015.

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 (loss) per common share, which includes the effect of all potentially dilutive securities unless their impact is anti-dilutive.

The following table sets forth the computation of diluted weighted average common shares outstanding for the three and nine months ended September 30, 2016 and 2015 (in thousands).

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Weighted average common shares outstanding | | | | |
| Basic | 93,384 | 84,685 | 90,016 | 80,481 |
| Dilutive effect of options, restricted stock units and preferred shares | 340 | — | — | — |
| Diluted weighted average common shares outstanding | 93,724 | 84,685 | 90,016 | 80,481 |

A total of 2.9 million options to purchase shares of the Company's common stock and 0.1 million restricted stock units were excluded from the diluted weighted average common shares outstanding for the nine months ended September 30, 2016, because their effects were anti-dilutive. Additionally, 1.0 million restricted shares, which are participating securities, were excluded from the calculations above for the nine months ended September 30, 2016, as the security holders do not have the obligation to share in the losses of the Company.

A total of 2.4 million options to purchase shares of the Company’s common stock and 0.1 million restricted stock units were excluded from the diluted weighted average common shares outstanding for both the three and nine months ended September 30, 2015, respectively, and zero and 1.5 million preferred shares were excluded from the calculations above for both the three and nine months ended September 30, 2015, respectively, because their effects were anti-dilutive. Additionally, 0.8 million restricted shares, which are participating securities, were excluded from the calculations above for both the three and

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

nine months ended September 30, 2015, respectively, as the security holders do not have the obligation to share in the losses of the Company.

Recent Accounting Pronouncements

Revenue from Contracts with Customers. In May 2014, the Financial Accounting Standards Board ("FASB") issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), which specifies how and when to recognize revenue. In addition, this standard requires expanded disclosures surrounding revenue recognition and is intended to improve, and converge with international standards, the financial reporting requirements for revenue from contracts with customers. This ASU will become effective for fiscal years beginning after December 15, 2017 with early adoption permitted for periods beginning after December 15, 2016. Entities can transition to the standard either retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. The Company is currently evaluating the impact, if any, of the adoption of this ASU on its consolidated financial statements.

Leases. In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), which requires the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous U.S. GAAP. This ASU will become effective for fiscal years beginning after December 15, 2018 with early adoption permitted. Entities are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. These practical expedients relate to the identification and classification of leases that commenced before the effective date, initial direct costs for leases that commenced before the effective date and the ability to use hindsight in evaluating lessee options to extend or terminate a lease or to purchase the underlying asset. The Company is currently evaluating the impact of the adoption of this ASU on its consolidated financial statements.

NOTE 3 - EQUITY

On March 11, 2016, the Company completed a public offering of 7,500,000 shares of its common stock. After deducting offering costs totaling approximately $0.8 million, the Company received net proceeds of approximately $141.5 million, which were used for general corporate purposes, including to fund a portion of the Company's 2016 capital expenditures.

NOTE 4 - ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company's asset retirement obligations for the nine months ended September 30, 2016 (in thousands).

| | |
|---|---|
| Beginning asset retirement obligations | $15,420 |
| Liabilities incurred during period | 1,903 |
| Liabilities settled during period | (317) |
| Revisions in estimated cash flows | 1,647 |
| Accretion expense | 828 |
| Ending asset retirement obligations | 19,481 |
| Less: current asset retirement obligations[1] | (29) |
| Long-term asset retirement obligations | $19,452 |

(1) Included in accrued liabilities in the Company's interim unaudited condensed consolidated balance sheet at September 30, 2016.

NOTE 5 - DEBT

At September 30, 2016, the Company had $400 million of outstanding 6.875% senior notes due 2023 (the "Notes"), $65.0 million in borrowings outstanding under the Company's revolving credit agreement (the "Credit Agreement") and approximately $0.8 million in outstanding letters of credit issued pursuant to the Credit Agreement. At November 1, 2016, the Company had $400.0 million in Notes outstanding, $95.0 million in borrowings outstanding under the Credit Agreement and approximately $0.8 million in outstanding letters of credit issued pursuant to the Credit Agreement.

NOTE 5 - DEBT - Continued

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. On May 3, 2016, the borrowing base under the Credit Agreement was reduced to $300.0 million from $375.0 million based on the lenders' review of the Company's proved oil and natural gas reserves at December 31, 2015. At September 30, 2016, the borrowing base under the Credit Agreement remained $300.0 million. During the fourth quarter of 2016, the lenders completed their review of the Company's estimated total proved oil and natural gas reserves at June 30, 2016, and as a result, in late October 2016, the borrowing base under the Credit Agreement was increased to $400.0 million. This October 2016 redetermination constituted the regularly scheduled November 1 redetermination.

In the event of a borrowing base increase, the Company is required to pay a fee to the lenders equal to a percentage of the amount of the increase, which is determined based on market conditions at the time of the borrowing base increase. If, upon a redetermination of the borrowing base, the borrowing base were to be less than the outstanding borrowings under the Credit Agreement at any time, the Company would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or to repay the deficit in equal installments over a period of six months.

The Company believes that it was in compliance with the terms of the Credit Agreement at September 30, 2016.

On April 14, 2015, the Company issued the Notes, which are jointly and severally guaranteed by certain subsidiaries of Matador (the "Guarantor Subsidiaries") on a full and unconditional basis (except for customary release provisions). At September 30, 2016, all of the Guarantor Subsidiaries are 100% owned by Matador, and any subsidiaries of Matador other than the Guarantor Subsidiaries are minor. Matador is a parent holding company and has no independent assets or operations, and there are no significant restrictions on the ability of Matador to obtain funds from the Guarantor Subsidiaries by dividend or loan.

NOTE 6 - INCOME TAXES

The Company's deferred tax assets exceed its deferred tax liabilities due to the deferred tax assets generated by the full-cost ceiling impairment charges recorded in prior periods; as a result, the Company established a valuation allowance against most of the deferred tax assets beginning in the third quarter of 2015. The Company retains a full valuation allowance at September 30, 2016 due to uncertainties regarding the future realization of its deferred tax assets. The valuation allowance will continue to be recognized until the realization of future deferred tax benefits are more likely than not to be utilized. The current tax benefit for the three and nine months ended September 30, 2016 represents a refund due from the Internal Revenue Service for 2015 income taxes.

The total income tax benefit for the three and nine months ended September 30, 2015 differed from amounts computed by applying the U.S. federal statutory tax rate to loss before income taxes due primarily to the recording of the valuation allowance against the net deferred tax assets, which resulted from the full-cost ceiling impairment recorded in the third quarter of 2015.

NOTE 7 - STOCK-BASED COMPENSATION

In February 2016, the Company granted awards of 243,428 shares of restricted stock and options to purchase 608,287 shares of the Company's common stock at an exercise price of $15.00 per share to certain of its employees. The fair value of these awards was approximately $7.0 million. All of these awards vest on the three-year anniversary of the grant date of these awards. In August 2016, the Company granted awards of 177,024 shares of restricted stock and options to purchase 39,903 shares of the Company's common stock at an exercise price of $22.70 per share to certain of its employees. The fair value of these awards was $4.3 million. All of these awards vest ratably over three years.

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS

At September 30, 2016, 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 2016 and 2017.

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

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The following is a summary of the Company’s open costless collar contracts for oil and natural gas at September 30, 2016.

| Commodity | Calculation Period | Notional Quantity (Bbl or MMBtu) | Weighted Average Price Floor ($/Bbl or $/MMBtu) | Weighted Average Price Ceiling ($/Bbl or $/MMBtu) | Fair Value of Asset (Liability) (thousands) |
|---|---|---|---|---|---|
| Oil | 10/01/2016 - 12/31/2016 | 690,000 | $ 42.48 | $ 61.16 | $ (788 ) |
| Oil | 01/01/2017 - 12/31/2017 | 2,160,000 | $ 39.56 | $ 50.36 | (11,097 ) |
| Natural Gas | 10/01/2016 - 12/31/2016 | 4,660,000 | $ 2.65 | $ 3.68 | (43 ) |
| Natural Gas | 01/01/2017 - 12/31/2017 | 16,860,000 | $ 2.40 | $ 3.59 | (2,049 ) |
| Total open derivative financial instruments | | | | | $ (13,977 ) |

These derivative financial instruments are subject to master netting arrangements; all but one counterparty allow for cross-commodity master netting provided the settlement dates for the commodities are the same. The Company does not present different types of commodities with the same counterparty on a net basis in its interim unaudited condensed consolidated balance sheets.

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

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The following table presents the gross asset and liability fair values of the Company's commodity price derivative financial instruments and the location of these balances in the interim unaudited condensed consolidated balance sheets as of September 30, 2016 and December 31, 2015 (in thousands).

| Derivative Instruments | Gross amounts recognized | Gross amounts netted in the condensed consolidated balance sheets | Net amounts presented in the condensed consolidated balance sheets |
|---|---|---|---|
| September 30, 2016 | | | |
| Current assets | $ 3,498 | $ (3,498) | $ — |
| Other assets | 1,512 | (1,512) | — |
| Current liabilities | (13,637) | 3,498 | (10,139) |
| Other liabilities | (5,350) | 1,512 | (3,838) |
| Total | $ (13,977) | $ — | $ (13,977) |
| December 31, 2015 | | | |
| Current assets | $ 16,767 | $ (483) | $ 16,284 |
| Current liabilities | (483) | 483 | — |
| Total | $ 16,284 | $ — | $ 16,284 |

The following table summarizes the location and aggregate fair value of all derivative financial instruments recorded in the interim unaudited condensed consolidated statements of operations for the periods presented (in thousands). These derivative financial instruments are not designated as hedging instruments.

| | | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| Type of Instrument | Location in Condensed Consolidated Statement of Operations | 2016 | 2015 | 2016 | 2015 |
| Derivative Instrument | | | | | |
| Oil | Revenues: Realized gain on derivatives | $ 837 | $ 17,056 | $ 6,861 | $ 42,013 |
| Natural Gas | Revenues: Realized gain on derivatives | 48 | 2,215 | 3,552 | 8,531 |
| Natural Gas Liquids | Revenues: Realized gain on derivatives | — | 591 | — | 1,602 |
| Realized gain on derivatives | | 885 | 19,862 | 10,413 | 52,146 |
| Oil | Revenues: Unrealized gain (loss) on derivatives | 2,007 | 6,421 | (24,967) | (19,923) |
| Natural Gas | Revenues: Unrealized gain (loss) on derivatives | 1,196 | 808 | (5,294) | (4,035) |
| Natural Gas Liquids | Revenues: Unrealized loss on derivatives | — | (496) | — | (1,398) |
| Unrealized gain (loss) on derivatives | | 3,203 | 6,733 | (30,261) | (25,356) |
| Total | | $ 4,088 | $ 26,595 | $ (19,848) | $ 26,790 |

NOTE 9 - FAIR VALUE MEASUREMENTS

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

Level 1 Unadjusted quoted prices for identical, unrestricted assets or liabilities in active markets.

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

NOTE 9 - FAIR VALUE MEASUREMENTS - Continued

| | |
|---|---|
| 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 which reflect a company’s own market assumptions. |

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.

The following tables summarize the valuation of the Company’s financial assets and liabilities that were accounted for at fair value on a recurring basis in accordance with the classifications provided above as of September 30, 2016 and December 31, 2015 (in thousands).

| | Fair Value Measurements at September 30, 2016 using | | | |
|---|---|---|---|---|
| Description | Level 1 | Level 2 | Level 3 | Total |
| Liabilities | | | | |
| Oil and natural gas derivatives | $— | $(13,977) | $ — | $(13,977) |
| Total | $— | $(13,977) | $ — | $(13,977) |

| | Fair Value Measurements at December 31, 2015 using | | | |
|---|---|---|---|---|
| Description | Level 1 | Level 2 | Level 3 | Total |
| Assets | | | | |
| Oil and natural gas derivatives | $— | $16,284 | $ — | $16,284 |
| Total | $— | $16,284 | $ — | $16,284 |

Additional disclosures related to derivative financial instruments are provided in Note 8.

Other Fair Value Measurements

At September 30, 2016 and December 31, 2015, the carrying values reported on the interim unaudited condensed consolidated balance sheets for accounts receivable, prepaid expenses, accounts payable, accrued liabilities, royalties payable, amounts due to affiliates, advances from joint interest owners, amounts due to joint ventures, income taxes payable and other current liabilities approximated their fair values due to their short-term maturities.

At September 30, 2016, the carrying value of borrowings under the Credit Agreement approximated its 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.

At September 30, 2016 and December 31, 2015, the fair value of the Notes was $413.1 million and $381.0 million, respectively, based on quoted market prices, which represent Level 1 inputs in the fair value hierarchy.

Table of Contents


NOTE 10 - COMMITMENTS AND CONTINGENCIES

Natural Gas and NGL Processing and Transportation Commitments

Effective September 1, 2012, the Company entered into a firm five-year natural gas processing and transportation agreement whereby the Company committed to transport the anticipated natural gas production from a significant portion of its Eagle Ford acreage in South Texas through the counterparty's system for processing at the counterparty's facilities. The agreement also includes firm transportation of the natural gas liquids extracted at the counterparty's processing plant downstream for fractionation. After processing, the residue natural gas is purchased by the counterparty at the tailgate of its processing plant and further transported under its natural gas transportation agreements. The arrangement contains fixed processing and liquids transportation and fractionation fees payable by the Company, and the revenue the Company receives for the residue natural gas 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 $1.6 million at September 30, 2016. The Company paid $0.7 million and $1.6 million in processing and transportation fees under this agreement during the three months ended September 30, 2016 and 2015, respectively, and $2.4 million and $4.3 million in processing and transportation fees under this agreement during the nine months ended September 30, 2016 and 2015, respectively.

In late 2015, the Company entered into a 15-year fixed-fee natural gas gathering and processing agreement whereby the Company committed to deliver the anticipated natural gas production from a significant portion of its Loving County, Texas acreage through the counterparty's gathering system for processing at the counterparty's facility. Under this agreement, if the Company does not meet the volume commitment for gathering and processing at the facility in a contract year, it will be required to pay a deficiency fee per MMBtu of natural gas deficiency. At the end of each year of the agreement, the Company can elect to have the previous year's actual gathering and processing volumes be the new minimum commitment for each of the remaining years of the contract. As such, the Company has the ability to unilaterally reduce the gathering and processing commitment if the Company's production in the Loving County area is less than the Company's currently projected production. If the Company ceased operations in this area at September 30, 2016, the total deficiency fee required to be paid would be approximately $12.0 million. In addition, if the Company elects to reduce the gathering and processing commitment in any year, the Company has the ability to elect to increase the committed volumes in any future year to the originally agreed gathering and processing commitment. Any quantity in excess of the volume commitment delivered in a contract year can be carried over to the next contract year for purposes of calculating the natural gas deficiency. The Company paid approximately $2.4 million in processing and gathering fees under this agreement during the three months ended September 30, 2016 and $7.1 million during the nine months ended September 30, 2016. The Company can elect to either sell the residue gas to the counterparty at the tailgate of its processing plant or have the counterparty deliver to the Company the residue gas in-kind to be sold to third parties downstream of the plant.

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 entered into longer-term contracts in order to secure new drilling rigs equipped with the latest technology in plays that were until recently experiencing heavy demand for drilling rigs. The Company would incur a termination obligation if the

Company elected to terminate a contract and the drilling contractor were unable to secure work for the contracted drilling rigs or if the drilling contractor were unable to secure replacement work for the contracted drilling rigs at the same daily rates being charged to the Company prior to the end of their respective contract terms. The Company's undiscounted minimum outstanding aggregate termination obligations under its drilling rig contracts were approximately $43.0 million at September 30, 2016.

The Company entered into an agreement in late 2015 with a third party for the engineering, procurement, construction and installation of a natural gas processing plant in the Rustler Breaks asset area in Eddy County, New Mexico. The plant was completed in the third quarter of 2016 and currently processes a portion of the Company's natural gas produced from certain of its wells in the Delaware Basin. At September 30, 2016, total remaining commitments under this contract were $4.2 million, and the Company made payments totaling $1.4 million during the three months ended September 30, 2016 and $19.2 million during the nine months ended September 30, 2016.

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

NOTE 10 - COMMITMENTS AND CONTINGENCIES - Continued

At September 30, 2016, 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 $11.2 million at September 30, 2016, which the Company expects to incur within the next few months.

Legal Proceedings

The Company is a party to several lawsuits encountered in the ordinary course of its business. While the ultimate outcome and impact to the Company cannot be predicted with certainty, in the opinion of management, it is remote that these lawsuits will have a material adverse impact on the Company's financial condition, results of operations or cash flows.

NOTE 11 - SUPPLEMENTAL DISCLOSURES

Accrued Liabilities

The following table summarizes the Company's current accrued liabilities at September 30, 2016 and December 31, 2015 (in thousands).

| | September 30, 2016 | December 31, 2015 |
|---|---|---|
| Accrued evaluated and unproved and unevaluated property costs | $ 44,551 | $ 54,586 |
| Accrued support equipment and facilities costs | 14,990 | 17,393 |
| Accrued lease operating expenses | 13,097 | 7,743 |
| Accrued interest on debt | 12,741 | 5,806 |
| Accrued asset retirement obligations | 29 | 254 |
| Accrued partners' share of joint interest charges | 5,646 | 4,565 |
| Other | 2,285 | 2,022 |
| Total accrued liabilities | $ 93,339 | $ 92,369 |

Supplemental Cash Flow Information

The following table provides supplemental disclosures of cash flow information for the nine months ended September 30, 2016 and 2015 (in thousands).

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2016 | 2015 |
| Cash paid for interest expense, net of amounts capitalized | $13,370 | $2,617 |
| Asset retirement obligations related to mineral properties | $2,588 | $1,487 |
| Asset retirement obligations related to support equipment and facilities | $644 | $89 |
| Decrease in liabilities for oil and natural gas properties capital expenditures | $(7,849 ) | $(30,282) |
| (Decrease) increase in liabilities for support equipment and facilities | $(2,687 ) | $2,525 |
| Stock-based compensation expense recognized as liability | $457 | $191 |
| Transfer of inventory from oil and natural gas properties | $655 | $586 |

NOTE 12 - SEGMENT INFORMATION

The Company operates in two business segments: (i) exploration and production and (ii) midstream. The exploration and production segment is engaged in the acquisition, exploration and development of oil and natural gas properties and is currently focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. The Company also operates in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. The midstream segment conducts midstream operations in support of the Company's exploration, development and production operations and provides natural gas processing, natural gas, oil and salt water gathering services and salt water disposal services to third parties on a limited basis.

The following tables present selected financial information for the periods presented regarding the Company's operating segments on a stand-alone basis, expenses that are not allocated to a segment and the consolidation and elimination entries necessary to arrive at the financial information for the Company on a consolidated basis (in thousands). On a consolidated basis, midstream services revenues primarily consist of those revenues from midstream operations related to third parties, including working interest owners in the Company's operated wells. All midstream services revenues associated with Company-owned production are eliminated in consolidation. In evaluating the operating results of the exploration and production and midstream segments, the Company does not allocate certain expenses to the individual segments, including general and administrative expenses.

| | Exploration and Production | Midstream | Corporate | Eliminations | Consolidated Company |
|---|---|---|---|---|---|
| Three Months Ended September 30, 2016 | | | | | |
| Oil and natural gas revenues | $ 82,794 | $ 285 | $ — | $ — | $ 83,079 |
| Midstream services revenues | — | 5,609 | — | (4,043 ) | 1,566 |
| Realized gain on derivatives | 885 | — | — | — | 885 |
| Unrealized gain on derivatives | 3,203 | — | — | — | 3,203 |
| Expenses (1) | 60,222 | 2,277 | 13,423 | (4,043 ) | 71,879 |
| Operating income (loss) (2) | $ 26,660 | $ 3,617 | $ (13,423 ) | $ — | $ 16,854 |
| Total Assets | $ 1,020,648 | $ 124,153 | $ 32,892 | $ — | $ 1,177,693 |
| Capital Expenditures | $ 116,279 | $ 17,370 | $ 1,903 | $ — | $ 135,552 |

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(1) Expenses include depreciation, depletion and amortization expenses of $28.9 million, $0.8 million and $0.3 million for the exploration and production, midstream and corporate segments, respectively.

(2) Includes $116,000 in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

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

NOTE 12 - SEGMENT INFORMATION - Continued

| | Exploration and Production | Midstream | Corporate | Eliminations | Consolidated Company |
|---|---|---|---|---|---|
| Three Months Ended September 30, 2015 | | | | | |
| Oil and natural gas revenues | $71,665 | $ 150 | $— | $ — | $71,815 |
| Midstream services revenues | — | 3,886 | — | (3,317 ) | 569 |
| Realized gain on derivatives | 19,862 | — | — | — | 19,862 |
| Unrealized gain on derivatives | 6,733 | — | — | — | 6,733 |
| Expenses (1) | 356,762 | 1,964 | 12,224 | (3,317 ) | 367,633 |
| Operating (loss) income (2) | $(258,502 ) | $ 2,072 | $(12,224) | $ — | $(268,654 ) |
| Total Assets | $1,169,283 | $ 83,089 | $28,150 | $ — | $1,280,522 |
| Capital Expenditures | $77,990 | $ 12,219 | $315 | $ — | $90,524 |

(1) Expenses include depreciation, depletion and amortization expenses of $44.6 million, $0.5 million and $0.1 million for the exploration and production, midstream and corporate segments, respectively, and full-cost ceiling impairment expense of $285.7 million for the exploration and production segment.
(2) Includes $45,000 in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

| | Exploration and Production | Midstream | Corporate | Eliminations | Consolidated Company |
|---|---|---|---|---|---|
| Nine Months Ended September 30, 2016 | | | | | |
| Oil and natural gas revenues | $195,467 | $874 | $— | $ — | $196,341 |
| Midstream services revenues | — | 11,168 | — | (8,212 ) | 2,956 |
| Realized gain on derivatives | 10,413 | — | — | — | 10,413 |
| Unrealized loss on derivatives | (30,261 ) | — | — | — | (30,261 ) |
| Expenses (1) | 327,585 | 5,373 | 40,089 | (8,212 ) | 364,835 |
| Operating (loss) income (2) | $(151,966 ) | $6,669 | $(40,089) | $ — | $(185,386 ) |
| Total Assets | $1,020,648 | $124,153 | $32,892 | $ — | $1,177,693 |
| Capital Expenditures | $278,396 | $49,620 | $5,485 | $ — | $333,501 |

(1) Expenses include depreciation, depletion and amortization expenses of $87.9 million, $1.7 million and $0.6 million for the exploration and production, midstream and corporate segments, respectively, and full-cost ceiling impairment expense of $158.6 million for the exploration and production segment.
(2) Includes $209,000 in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

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

NOTE 12 - SEGMENT INFORMATION - Continued

| | Exploration and Production | Midstream | Corporate | Eliminations | Consolidated Company |
|---|---|---|---|---|---|
| Nine Months Ended September 30, 2015 | | | | | |
| Oil and natural gas revenues | $221,768 | $ 360 | $— | $ — | $222,128 |
| Midstream services revenues | — | 8,294 | — | (6,910 ) | 1,384 |
| Realized gain on derivatives | 52,146 | — | — | — | 52,146 |
| Unrealized loss on derivatives | (25,356 ) | — | — | — | (25,356 ) |
| Expenses (1) | 798,044 | 3,990 | 38,823 | (6,910 ) | 833,947 |
| Operating (loss) income (2) | $(549,486 ) | $ 4,664 | $(38,823) | $ — | $(583,645 ) |
| Total Assets | $1,169,283 | $ 83,089 | $28,150 | $ — | $1,280,522 |
| Capital Expenditures | $307,896 | $ 47,804 | $394 | $ — | $356,094 |

(1) Expenses include depreciation, depletion and amortization expenses of $142.0 million, $1.2 million and $0.3 million for the exploration and production, midstream and corporate segments, respectively, and full-cost ceiling impairment expense of $581.9 million for the exploration and production segment.
(2) Includes $156,000 in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

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 interim unaudited condensed consolidated financial statements and related notes thereto contained herein and in our Annual Report on Form 10-K for the year ended December 31, 2015 (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 Quarterly 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,” “forecasted,” “hypothetical,” “intend,” “may,” “might,” “plan,” “potential,” “predict,” “project,” “should” or other similar wor
not all forward- looking statements contain such identifying 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: general economic conditions, changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids, the success of our drilling program, the timing of planned capital expenditures, sufficient cash flow from operations together with available borrowing capacity under our credit agreement,

Table of Contents

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, our ability to integrate acquisitions, including the integration of Harvey E. Yates Company, with our business, weather and environmental conditions, 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;
- our ability to negotiate and consummate acquisition and divestiture opportunities;
- government regulation and taxation of the oil and natural gas industry;
- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- the integration of acquisitions, including the integration of Harvey E. Yates Company, with our business;
- our ability to construct and operate midstream facilities;
- 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; and
- our plans, objectives, expectations and intentions contained in this Quarterly Report that are not historical.

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 Delaware Basin in Southeast New Mexico and West Texas. We also operate in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. Additionally, we conduct midstream operations in support of our exploration, development and production operations and provide natural gas processing, natural gas, oil and salt water gathering services and salt water disposal services to third parties on a limited basis.

Table of Contents

Third Quarter and Year-to-Date Highlights

Quarterly oil, natural gas and oil equivalent production results for the third quarter of 2016 were the best in our history. For the three months ended September 30, 2016, our total oil equivalent production was 2.70 million BOE, and our average daily oil equivalent production was 29,381 BOE per day, of which 14,960 Bbl per day, or 51%, was oil and 86.5 MMcf per day, or 49%, was natural gas. Our oil production of 1.38 million Bbl for the three months ended September 30, 2016 increased 19% year-over-year from 1.16 million Bbl for the three months ended September 30, 2015. Our natural gas production of 8.0 Bcf for the three months ended September 30, 2016 increased 7% year-over-year from 7.5 Bcf for the three months ended September 30, 2015.

For the nine months ended September 30, 2016, our total oil equivalent production was 7.42 million BOE and our average daily oil equivalent production was 27,091 BOE per day, of which 13,322 Bbl per day, or 49%, was oil and 82.6 MMcf per day, or 51%, was natural gas. Our total oil equivalent production of 7.42 million BOE for the nine months ended September 30, 2016 increased 7% year-over-year from 6.94 million BOE for the nine months ended September 30, 2015. Our oil production of 3.65 million Bbl for the nine months ended September 30, 2016 increased 6% year-over-year from 3.43 million Bbl for the nine months ended September 30, 2015. Our natural gas production of 22.6 Bcf for the nine months ended September 30, 2016 increased 7% year-over-year from 21.1 Bcf for the nine months ended September 30, 2015.

During the third quarter of 2016, our oil and natural gas revenues were $83.1 million, an increase of 16% from oil and natural gas revenues of $71.8 million during the third quarter of 2015. The increase in our oil and natural gas revenues was due to (i) the 19% increase in our oil production to 1.38 million Bbl in the third quarter of 2016, as compared to 1.16 million Bbl produced in the third quarter of 2015 and (ii) the 7% increase in our natural gas production to 8.0 Bcf in the third quarter of 2016, as compared to 7.5 Bcf produced in the third quarter of 2015. The increase in oil and natural gas production was primarily a result of our ongoing delineation and development drilling in the Delaware Basin, which offset declining production in the Eagle Ford and Haynesville shales where we have significantly reduced our activity since late 2014 and early 2015. This increase in oil and natural gas revenues was also partly attributable to the increase in the weighted average natural gas price to $3.08 per Mcf realized in the third quarter of 2016, as compared to the weighted average natural gas price of $2.90 per Mcf realized in the third quarter of 2015.

For the third quarter of 2016, we reported net income of approximately $11.9 million, or $0.13 per diluted common share on a GAAP basis, as compared to a net loss of $242.1 million, or $(2.86) per diluted common share, for the third quarter of 2015. For the third quarter of 2016, our Adjusted EBITDA, a non-GAAP financial measure, was $47.3 million, a decrease of 19% from Adjusted EBITDA of $58.0 million during the third quarter of 2015. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see "— Liquidity and Capital Resources — Non-GAAP Financial Measures." For more information regarding our financial results for 2016, see "— Results of Operations" below.

For the nine months ended September 30, 2016, our oil and natural gas revenues were $196.3 million, a decrease of 12% from oil and natural gas revenues of $222.1 million for the nine months ended September 30, 2015. This decrease was attributable to a sharp decline in the weighted average oil and natural gas prices to $38.75 per Bbl and $2.43 per Mcf, respectively, realized in the nine months ended September 30, 2016 from weighted average oil and natural gas prices of $47.36 per Bbl and $2.83 per Mcf, respectively, realized in the nine months ended September 30, 2015. The decrease in our oil and natural gas revenues was mitigated by the 6% increase in our oil production to 3.65 million Bbl for the nine months ended September 30, 2016, as compared to 3.43 million Bbl produced for the nine months ended September 30, 2015, and by the 7% increase in our natural gas production to 22.6 Bcf for the nine months ended September 30, 2016, as compared to 21.1 Bcf for the nine months ended September 30, 2015. This increase in oil and natural gas production was attributable to the same operations noted above for the third quarter of 2016.

For the nine months ended September 30, 2016, we reported a net loss of approximately $201.6 million, or $(2.24) per diluted common share on a GAAP basis, a decrease of 55%, as compared to a net loss of $449.4 million, or $(5.58) per diluted common share, for the nine months ended September 30, 2015. For the nine months ended September 30, 2016, our Adjusted EBITDA was $103.4 million, a decrease of 41% from Adjusted EBITDA of $174.9 million for the nine months ended September 30, 2015. Adjusted EBITDA is a non-GAAP financial measure. For a definition of

Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see "— Liquidity and Capital Resources — Non-GAAP Financial Measures." For more information regarding our financial results for 2016, see "— Results of Operations" below.

During the third quarter of 2016, we continued to operate three drilling rigs in the Delaware Basin, as we have throughout 2016. In the third quarter and at November 1, 2016, one of these rigs was drilling in the Wolf asset area in Loving County, Texas, one was drilling in the Rustler Breaks asset area in Eddy County, New Mexico and one was drilling in the western portion of our Ranger asset area in Lea County, New Mexico. We contracted a fourth drilling rig in late August 2016 to begin drilling our first salt water disposal well in the Rustler Breaks asset area. After this well is finished being drilled in early

November 2016, we intend to move this rig to our Wolf asset area to drill a third salt water disposal well there. Although we had made no commitment to do so at November 1, 2016, we are considering retaining the fourth drilling rig following the drilling of the Wolf salt water disposal well, and if so, we expect to move this rig to our Rustler Breaks asset area in early December 2016 and begin operating two drilling rigs there.

We began producing oil and natural gas from a total of 15 gross (8.4 net) wells in the Rustler Breaks and Wolf asset areas during the third quarter of 2016, including nine gross (7.9 net) operated and six gross (0.5 net) non-operated horizontal wells. Most of these wells were placed on production during August and September 2016 and, as a result, did not contribute fully to third quarter production volumes. In the Rustler Breaks asset area, we began producing oil and natural gas from a total of 11 gross (4.6 net) wells during the third quarter of 2016, including five gross (4.1 net) operated and six gross (0.5 net) non-operated horizontal wells. Of the five gross operated wells in the Rustler Breaks asset area, four were Wolfcamp A-XY completions and one was a lower Wolfcamp B (Blair Shale) completion. The six gross non-operated wells in the Rustler Breaks asset area included four Wolfcamp B (Blair Shale) completions and two Second Bone Spring completions. In addition, we began producing oil and natural gas from four gross (3.8 net) operated horizontal wells at Wolf during the third quarter of 2016, including one Wolfcamp A-Y completion and three Second Bone Spring completions.

As a result of our ongoing drilling and completion operations in these asset areas, our Delaware Basin production has continued to increase over the past twelve months. Our total Delaware Basin production for the third quarter of 2016 was 18,498 BOE per day, consisting of 11,751 Bbl of oil per day and 40.5 MMcf of natural gas per day, a 2.4-fold increase from production of 7,551 BOE per day, consisting of 5,489 Bbl of oil per day and 12.4 MMcf of natural gas per day, in the third quarter of 2015. The Delaware Basin contributed approximately 79% of our daily oil production and approximately 47% of our daily natural gas production in the third quarter of 2016, as compared to approximately 44% of our daily oil production and approximately 15% of our daily natural gas production in the third quarter of 2015.

In late August 2016, we successfully completed and began operating the Black River cryogenic natural gas processing plant built in our Rustler Breaks asset area in Eddy County, New Mexico. The Black River processing plant has an inlet capacity of approximately 60 MMcf of natural gas per day, which is almost twice the size of the previous cryogenic processing plant we built in our Wolf asset area in Loving County, Texas and subsequently sold to an affiliate of EnLink Midstream Partners, LP in October 2015. The Black River plant and associated gathering system was built to support our ongoing and future development efforts at Rustler Breaks and to provide us with priority one takeaway and processing services for our Rustler Breaks natural gas production. It should also provide additional income through the gathering and processing of third-party natural gas. The Black River plant was completed on time and on budget and, at November 1, 2016, had processed between 30 and 40 MMcf per day (on a gross basis) during its first two months in operation. We had previously completed the installation and testing of a 12-inch natural gas trunk line and associated gathering lines running throughout the length of our Rustler Breaks acreage position, and these natural gas gathering lines are being used to gather almost all of our natural gas production at Rustler Breaks.

On November 1, 2016, we adjusted our 2016 capital expenditure budget from $325.0 million to between $425.0 and $450.0 million, primarily to take advantage of a number of strategic lease and minerals acquisition opportunities as well as several new midstream initiatives in the Delaware Basin. More specifically, these changes in our capital budget should allow us (i) to take advantage of opportunities to make strategic additions to our Delaware Basin acreage and minerals position, particularly in the third and fourth quarters of 2016, as operational results have exceeded expectations and commodity prices have improved, (ii) to accelerate the timing of several important midstream projects originally planned for 2017, which add to our midstream asset base and (iii) to potentially add a fourth rig to our Delaware Basin drilling program in December 2016. Further, this estimated increase in our capital budget for 2016 does not include any additional funds allocated to drilling, completing and equipping wells in 2016. At September 30, 2016, we had incurred $333.5 million of our adjusted 2016 capital expenditure budget of between $425.0 and $450.0 million. For more information regarding our 2016 capital expenditure budget, see "— Liquidity and Capital Resources" below.

At December 31, 2015, we held approximately 157,100 gross (88,800 net) leased acres in the Permian Basin in Southeast New Mexico and West Texas, primarily in the Delaware Basin in Lea and Eddy Counties, New Mexico and

Loving County, Texas. Between January 1, 2016 and October 31, 2016, we added approximately 10,600 gross (7,300 net) leased acres in Southeast New Mexico and West Texas, bringing our total Permian Basin acreage position at October 31, 2016 to approximately 165,500 gross (94,700 net) leased acres, almost all of which was located in the Delaware Basin. At October 31, 2016, we had sold approximately 600 net acres and allowed to expire approximately 800 net acres in non-core areas of the Permian Basin in 2016. During the third quarter of 2016, we also acquired mineral ownership in approximately 600 net acres in our Rustler Breaks and Ranger/Arrowhead asset areas. This brings our total acquired mineral ownership in the Delaware Basin since January 1, 2016 to approximately 7,900 gross (2,300 net) mineral acres. We plan to continue our leasing and acquisition efforts in the Delaware Basin during the remainder of 2016 and may also consider acquiring acreage in the Eagle Ford and Haynesville shales as strategic opportunities are identified.

Table of Contents

Estimated Proved Reserves

The following table sets forth our estimated total proved oil and natural gas reserves at September 30, 2016, December 31, 2015 and September 30, 2015. 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 Delaware Basin and the Eagle Ford shale, the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers. These reserves estimates were prepared in accordance with the SEC's rules for oil and natural gas reserves reporting. The estimated reserves shown are for proved reserves only and do not include any unproved reserves classified as probable or possible reserves that might exist for our properties, nor do they include any consideration that would be attributable to interests in unproved and unevaluated acreage beyond those tracts for which proved reserves have been estimated. Proved oil and natural gas reserves are quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our total proved reserves are estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

| | September 30, 2016 | December 31, 2015 | September 30, 2015 |
|---|---|---|---|
| Estimated Proved Reserves Data: (1) (2) | | | |
| Estimated proved reserves: | | | |
| Oil (MBbl)(3) | 55,031 | 45,644 | 42,531 |
| Natural Gas (Bcf)(4) | 279.4 | 236.9 | 267.5 |
| Total (MBOE)(5) | 101,604 | 85,127 | 87,109 |
| Estimated proved developed reserves: | | | |
| Oil (MBbl)(3) | 21,204 | 17,129 | 17,413 |
| Natural Gas (Bcf)(4) | 118.8 | 101.4 | 97.7 |
| Total (MBOE)(5) | 41,012 | 34,037 | 33,685 |
| Percent developed | 40.4 % | 40.0 % | 38.7 % |
| Estimated proved undeveloped reserves: | | | |
| Oil (MBbl)(3) | 33,827 | 28,515 | 25,118 |
| Natural Gas (Bcf)(4) | 160.6 | 135.5 | 169.8 |
| Total (MBOE)(5) | 60,592 | 51,090 | 53,424 |
| Standardized Measure(6) (in millions) | $ 516.8 | $ 529.2 | $ 673.8 |
| PV-10(7) (in millions) | $ 524.7 | $ 541.6 | $ 692.7 |

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

(2) Our estimated proved reserves, Standardized Measure and PV-10 were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic averages of the first-day-of-the-month prices for the period from October 2015 through September 2016 were $38.17 per Bbl for oil and $2.28 per MMBtu for natural gas, for the period from January 2015 through December 2015 were $46.79 per Bbl for oil and $2.59 per MMBtu for natural gas and for the period from October 2014 through September 2015 were $55.73 per Bbl for oil and $3.06 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) 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.

(7) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. Our PV-10 at September 30, 2016,

Table of Contents

December 31, 2015 and September 30, 2015 may be reconciled to the Standardized Measure of discounted future net cash flows at such dates by reducing our PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at September 30, 2016, December 31, 2015 and September 30, 2015 were, in millions, $7.9, $12.4 and $18.9, respectively.

At September 30, 2016, our estimated total proved oil and natural gas reserves were 101.6 million BOE, an all-time high, including 55.0 million Bbl of oil and 279.4 Bcf of natural gas, with a Standardized Measure of $516.8 million and a PV-10, a non-GAAP financial measure, of $524.7 million. At December 31, 2015, our estimated total proved oil and natural gas reserves were 85.1 million BOE, including 45.6 million Bbl of oil and 236.9 Bcf of natural gas, and at September 30, 2015, our estimated total proved oil and natural gas reserves were 87.1 million BOE, including 42.5 million Bbl of oil and 267.5 Bcf of natural gas. Our proved oil reserves of 55.0 million Bbl at September 30, 2016, also an all-time high, increased 21%, as compared to 45.6 million Bbl at December 31, 2015, and increased 29%, as compared to 42.5 million Bbl at September 30, 2015. At September 30, 2016, approximately 40% of our total proved reserves were proved developed reserves, 54% of our total proved reserves were oil and 46% of our total proved reserves were natural gas.

As a result of our drilling, completion and delineation activities in West Texas and Southeast New Mexico since 2014, our Delaware Basin oil and natural gas reserves have become a more significant component of our total oil and natural gas reserves. Our estimated Delaware Basin proved oil and natural gas reserves have increased 87% from 39.6 million BOE at September 30, 2015, or 46% of our total proved oil and natural gas reserves, including 25.6 million Bbl of oil and 84.0 Bcf of natural gas, to 74.0 million BOE, or 73% of our total proved oil and natural gas reserves, including 44.1 million Bbl of oil and 179.3 Bcf of natural gas, at September 30, 2016.

There have been no changes to the technology we used to establish reserves or to our internal control over the reserves estimation process from those set forth in the Annual Report.

Critical Accounting Policies

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

Recent Accounting Pronouncements

See Note 2 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for the Company’s adoption of a new accounting pronouncement in the second quarter of 2016 and for a summary of recent accounting pronouncements that we believe may have an impact on our financial statements upon adoption.

Table of Contents

Results of Operations

Revenues

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Operating Data: | | | | |
| Revenues (in thousands):[1] | | | | |
| Oil | $58,589 | $50,173 | $141,437 | $162,424 |
| Natural gas | 24,490 | 21,642 | 54,904 | 59,704 |
| Total oil and natural gas revenues | 83,079 | 71,815 | 196,341 | 222,128 |
| Third-party midstream services revenues | 1,566 | 569 | 2,956 | 1,384 |
| Realized gain on derivatives | 885 | 19,862 | 10,413 | 52,146 |
| Unrealized gain (loss) on derivatives | 3,203 | 6,733 | (30,261) | (25,356) |
| Total revenues | $88,733 | $98,979 | $179,449 | $250,302 |
| Net Production Volumes:[1] | | | | |
| Oil (MBbl)[2] | 1,376 | 1,161 | 3,650 | 3,429 |
| Natural gas (Bcf)[3] | 8.0 | 7.5 | 22.6 | 21.1 |
| Total oil equivalent (MBOE)[4] | 2,703 | 2,405 | 7,423 | 6,941 |
| Average daily production (BOE/d)[5] | 29,381 | 26,137 | 27,091 | 25,427 |
| Average Sales Prices: | | | | |
| Oil, without realized derivatives (per Bbl) | $42.57 | $43.21 | $38.75 | $47.36 |
| Oil, with realized derivatives (per Bbl) | $43.18 | $57.90 | $40.63 | $59.61 |
| Natural gas, without realized derivatives (per Mcf) | $3.08 | $2.90 | $2.43 | $2.83 |
| Natural gas, with realized derivatives (per Mcf) | $3.08 | $3.28 | $2.58 | $3.31 |

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

(2) One thousand barrels of oil.

(3) One billion cubic feet of natural gas.

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

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

Three Months Ended September 30, 2016 as Compared to Three Months Ended September 30, 2015

Oil and natural gas revenues. Our oil and natural gas revenues increased $11.3 million to $83.1 million, or an increase of 16%, for the three months ended September 30, 2016, as compared to $71.8 million for the three months ended September 30, 2015. Our oil revenues increased $8.4 million, or 17%, to $58.6 million for the three months ended September 30, 2016, as compared to $50.2 million for the three months ended September 30, 2015. The increase in oil revenues was primarily from an increase in oil production of 19% to 1.38 million Bbl of oil for the three months ended September 30, 2016, or about 14,960 Bbl of oil per day, as compared to 1.16 million Bbl of oil, or about 12,617 Bbl of oil per day, for the three months ended September 30, 2015. The increase in oil production was primarily a result of our ongoing delineation and development drilling in the Delaware Basin, which offset declining oil production in the Eagle Ford shale where we have not drilled any new operated wells since the second quarter of 2015. The increase in oil revenues was partially offset by a lower weighted average oil price realized for the three months ended September 30, 2016 of $42.57 per Bbl, as compared to $43.21 per Bbl realized for the three months ended September 30, 2015. Our natural gas revenues increased by $2.8 million, or 13%, to $24.5 million for the three months ended September 30, 2016, as compared to $21.6 million for the three months ended September 30, 2015. The increase in natural gas revenues resulted from a higher weighted average natural gas price realized for the three months ended September 30, 2016 of $3.08 per Mcf, as compared to $2.90 per Mcf realized for the three months ended September 30, 2015, and the 7% increase in our natural gas production to 8.0 Bcf for the three months ended September 30, 2016, as compared to 7.5 Bcf for the three months ended September 30, 2015. The increased natural gas production was primarily attributable to our ongoing delineation and development drilling in the Delaware Basin, which offset declining natural gas production in the Eagle Ford and Haynesville shales where we have significantly reduced our activity since late 2014 and early 2015.

Table of Contents

Third-party midstream services revenues. During the third quarter of 2016, our midstream operations became a reportable business segment under U.S. GAAP. Thus, we reported third-party midstream services revenues separately for the first time in our unaudited condensed consolidated statements of operations. Third-party midstream services revenues are primarily those revenues from midstream operations related to third parties, including working interest owners in our operated wells; all midstream services revenues associated with Company-owned production are eliminated in consolidation. Our midstream services revenues from third-parties increased $1.0 million to $1.6 million, or an increase of 175%, for the three months ended September 30, 2016, as compared to $0.6 million for the three months ended September 30, 2015. This increase is primarily attributable to a significant increase in third-party salt water being disposed of at our commercial facilities in the Wolf asset area and to the Black River natural gas processing plant becoming operational in late August 2016. Prior to this time, we had no significant midstream services revenues attributable to natural gas processing plant operations.

Realized gain on derivatives. Our realized gain on derivatives was $0.9 million for the three months ended September 30, 2016, as compared to a realized gain of $19.9 million for the three months ended September 30, 2015. We realized net gains of $0.8 million and $48,500 from our oil and natural gas derivative contracts, respectively, for the three months ended September 30, 2016. For the three months ended September 30, 2015, we realized net gains of $17.1 million, $2.2 million and $0.6 million attributable to our oil, natural gas and natural gas liquids (“NGL”) derivative contracts, respectively. The realized gains on our oil and natural gas derivative contracts during the respective periods were attributable to commodity prices being below the floor prices of certain of our oil and natural gas costless collar contracts for the three months ended September 30, 2016 and 2015. The realized gain on our NGL derivative contracts during the three months ended September 30, 2015 resulted from NGL prices that were lower than the fixed prices of our NGL swap contracts; we had no open NGL derivative contracts in 2016. The average floor prices of our oil costless collar contracts were $42.48 per Bbl and $67.11 per Bbl for the three months ended September 30, 2016 and 2015, respectively. The average ceiling prices of our oil costless collar contracts were $61.16 per Bbl and $84.60 per Bbl for the three months ended September 30, 2016 and 2015, respectively. The average floor prices of our natural gas costless collar contracts were $2.60 per MMBtu and $3.26 per MMBtu for the three months ended September 30, 2016 and 2015, respectively. The average ceiling prices of our natural gas costless collar contracts were $3.53 per MMBtu and $3.94 per MMBtu for the three months ended September 30, 2016 and 2015, respectively. Our total oil and natural gas volumes hedged for the three months ended September 30, 2016 were 15% lower and 31% lower, respectively, than the total oil and natural gas volumes hedged for the same period in 2015.

Unrealized gain on derivatives. Our unrealized gain on derivatives was $3.2 million for the three months ended September 30, 2016, as compared to an unrealized gain of $6.7 million for the three months ended September 30, 2015. During the three months ended September 30, 2016, the aggregate net fair value of our open oil and natural gas derivative contracts increased to a liability of $14.0 million from a liability of $17.2 million at June 30, 2016, resulting in an unrealized gain on derivatives of $3.2 million for the three months ended September 30, 2016. During the three months ended September 30, 2016, the net fair value of our open oil derivative contracts increased by $2.0 million, and the net fair value of our open natural gas derivative contracts increased by $1.2 million. During the three months ended September 30, 2015, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts increased to an asset of $30.2 million from $23.5 million at June 30, 2015, resulting in an unrealized gain on derivatives of $6.7 million for the three months ended September 30, 2015.

Nine Months Ended September 30, 2016 as Compared to Nine Months Ended September 30, 2015

Oil and natural gas revenues. Our oil and natural gas revenues decreased by approximately $25.8 million, or 12%, to $196.3 million for the nine months ended September 30, 2016, as compared to $222.1 million for the nine months ended September 30, 2015. Our oil revenues decreased by 13% to $141.4 million for the nine months ended September 30, 2016, as compared to $162.4 million for the nine months ended September 30, 2015. The decrease in oil revenues resulted primarily from a lower weighted average oil price realized for the nine months ended September 30, 2016 of $38.75 per Bbl, as compared to $47.36 per Bbl realized for the nine months ended September 30, 2015. Our oil production increased by 6% to 3.65 million Bbl for the nine months ended September 30, 2016, or about 13,322 Bbl of oil per day, as compared to 3.43 million Bbl of oil, or about 12,562 Bbl of oil per day, for the nine months ended September 30, 2015. The increase in oil production was primarily a result of our ongoing delineation and development drilling in the Delaware Basin, which offset declining oil production in the Eagle Ford shale where we have not drilled any new operated wells since the second quarter of 2015. Our natural gas revenues decreased by $4.8 million, or 8%, to $54.9 million for the nine months ended September 30, 2016, as compared to $59.7 million for the nine months ended September 30, 2015. Our natural gas production increased by 7% to 22.6 Bcf for the nine months ended September 30, 2016, as compared to 21.1 Bcf for the nine months ended September 30, 2015. The increase in natural gas production was primarily attributable to increased natural gas production associated with our operations in the Delaware Basin and new, non-operated Haynesville shale wells completed and placed on production on our Elm Grove properties in Northwest Louisiana during the latter half of 2015 and into 2016. This production increase was more than offset by a lower weighted average natural gas price of $2.43 per Mcf realized during the nine months ended September 30, 2016, as compared to a weighted average natural gas price of $2.83 per Mcf realized during the nine months ended September 30, 2015.

Table of Contents

Third-party midstream services revenues. Our midstream services revenues from third parties increased $1.6 million to $3.0 million, or an increase of 114% for the nine months ended September 30, 2016, as compared to $1.4 million for the nine months ended September 30, 2015. This is primarily attributable to a significant increase in third-party salt water being disposed of at our commercial facilities in the Wolf asset area and to the Black River natural gas processing plant becoming operational in late August 2016. Prior to this time, we had no significant midstream services revenues attributable to natural gas processing plant operations.
Realized gain on derivatives. We realized a gain on derivatives of approximately $10.4 million for the nine months ended September 30, 2016, as compared to a gain of approximately $52.1 million for the nine months ended September 30, 2015. For the nine months ended September 30, 2016, we realized net gains of approximately $6.9 million and $3.6 million attributable to our oil and natural gas derivative contracts, respectively. For the nine months ended September 30, 2015, we realized net gains of approximately $42.0 million, $8.5 million and $1.6 million attributable to our oil, natural gas and NGL derivative contracts, respectively. The net gain realized from our derivative contracts for the nine months ended September 30, 2016 resulted from oil and natural gas prices that were below the floor prices of certain of our oil and natural gas derivative contracts. The average floor prices of our oil costless collar contracts were $43.17 per Bbl and $71.77 per Bbl for the nine months ended September 30, 2016 and 2015, respectively. The average ceiling prices of our oil costless collar contracts were $63.04 per Bbl and $89.04 per Bbl for the nine months ended September 30, 2016 and 2015, respectively. The average floor prices of our natural gas costless collar contracts were $2.61 per MMBtu and $3.42 per MMBtu for the nine months ended September 30, 2016 and 2015, respectively. The average ceiling prices of our natural gas costless collar contracts were $3.55 per MMBtu and $4.19 per MMBtu for the nine months ended September 30, 2016 and 2015, respectively. Our total oil and natural gas volumes hedged for the nine months ended September 30, 2016 were 2% lower and 35% lower, respectively, than the total oil and natural gas volumes hedged for the same period in 2015.
Unrealized loss on derivatives. Our unrealized loss on derivatives was approximately $30.3 million for the nine months ended September 30, 2016, as compared to an unrealized loss of approximately $25.4 million for the nine months ended September 30, 2015. During the period from December 31, 2015 through September 30, 2016, the aggregate net fair value of our open oil and natural gas derivative contracts decreased from an asset of approximately $16.3 million to a liability of approximately $14.0 million, resulting in an unrealized loss on derivatives of approximately $30.3 million for the nine months ended September 30, 2016. During the period from December 31, 2014 through September 30, 2015, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts decreased from $55.5 million to $30.2 million, resulting in an unrealized loss on derivatives of $25.4 million for the nine months ended September 30, 2015.

Table of Contents

Expenses

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

| (In thousands, except expenses per BOE) | Three Months Ended September 30, 2016 | Three Months Ended September 30, 2015 | | Nine Months Ended September 30, 2016 | Nine Months Ended September 30, 2015 | |
|---|---|---|---|---|---|---|
| Expenses: | | | | | | |
| Production taxes, transportation and processing | $12,388 | $9,426 | | $30,846 | $26,734 | |
| Lease operating | 14,605 | 13,466 | | 41,300 | 40,140 | |
| Plant and other midstream services operating | 1,449 | 1,450 | | 3,537 | 2,772 | |
| Depletion, depreciation and amortization | 30,015 | 45,237 | | 90,185 | 143,477 | |
| Accretion of asset retirement obligations | 276 | 182 | | 828 | 427 | |
| Full-cost ceiling impairment | — | 285,721 | | 158,633 | 581,874 | |
| General and administrative | 13,146 | 12,151 | | 39,506 | 38,523 | |
| Total expenses | $71,879 | $367,633 | | $364,835 | $833,947 | |
| Operating income (loss) | $16,854 | $(268,654) | | $(185,386) | $(583,645) | |
| Other income (expense): | | | | | | |
| Net gain (loss) on asset sales and inventory impairment | $1,073 | $— | | $3,140 | $(97) | |
| Interest expense | (6,880) | (7,229) | | (20,244) | (15,168) | |
| Other (expense) income | (141) | 564 | | (17) | 637 | |
| Total other expense | $(5,948) | $(6,665) | | $(17,121) | $(14,628) | |
| Income (loss) before income taxes | $10,906 | $(275,319) | | $(202,507) | $(598,273) | |
| Total income tax benefit | (1,141) | (33,305) | | (1,141) | (149,045) | |
| Net income attributable to non-controlling interest in subsidiaries | (116) | (45) | | (209) | (156) | |
| Net income (loss) attributable to Matador Resources Company shareholders | $11,931 | $(242,059) | | $(201,575) | $(449,384) | |
| Expenses per BOE: | | | | | | |
| Production taxes, transportation and processing | $4.58 | $3.92 | (1) | $4.16 | $3.85 | (2) |
| Lease operating | $5.40 | $5.60 | (3) | $5.56 | $5.78 | (4) |
| Plant and other midstream services operating | $0.54 | $0.60 | | $0.48 | $0.40 | |
| Depletion, depreciation and amortization | $11.10 | $18.81 | | $12.15 | $20.67 | |
| General and administrative | $4.86 | $5.05 | | $5.32 | $5.55 | |

(1) $0.06 per BOE reclassified to third-party midstream services revenues due to the midstream segment becoming a reportable segment in the third quarter of 2016.

(2) $0.02 per BOE reclassified to third-party midstream services revenues due to the midstream segment becoming a reportable segment in the third quarter of 2016.

(3) $0.60 per BOE reclassified to plant and other midstream services operating expenses due to the midstream segment becoming a reportable segment in the third quarter of 2016.

(4) $0.40 per BOE reclassified to plant and other midstream services operating expenses due to the midstream segment becoming a reportable segment in the third quarter of 2016.

Three Months Ended September 30, 2016 as Compared to Three Months Ended September 30, 2015

Production taxes, transportation and processing. Our production taxes, transportation and processing expenses increased by $3.0 million to $12.4 million, or an increase of 31%, for the three months ended September 30, 2016, as compared to $9.4 million for the three months ended September 30, 2015. On a unit-of-production basis, our production taxes, transportation and processing expenses increased by 17% to $4.58 per BOE for the three months ended September 30, 2016, as compared to $3.92 per BOE for the three months ended September 30, 2015. The increase in production taxes, transportation and processing expenses was attributable to higher production taxes resulting from increased oil and natural gas revenues between the comparable periods and to higher natural gas transportation and processing expenses of $7.3 million for the three months ended September 30, 2016, as compared to natural gas transportation and processing expenses of $5.9 million for the three months ended September 30, 2015. This increase of $1.5 million was primarily due to the increase in natural gas production in the Delaware Basin as a percentage o

Table of Contents

f our total natural gas production for the three months ended September 30, 2016, as compared to the three months ended September 30, 2015. Natural gas transportation and processing expenses are higher in the Delaware Basin, as compared to the Eagle Ford shale, as the natural gas gathering and processing infrastructure has yet to meet the demand for these services due to the increased drilling activity in the Delaware Basin over the last few years. We have begun to incur lower processing expenses for most of the natural gas produced in our Rustler Breaks asset area in Eddy County, New Mexico due to the start up in late August 2016 of the cryogenic natural gas processing plant we constructed in the Rustler Breaks asset area, and we expect to fully realize the impact of these lower processing expenses once the plant is operational for an entire quarter.

Our production taxes increased by $1.2 million to $4.6 million for the three months ended September 30, 2016, as compared to $3.4 million for the three months ended September 30, 2015, primarily due to the 16% increase in oil and natural gas revenues in the third quarter of 2016 as compared to the third quarter of 2015.

Lease operating. Our lease operating expenses increased by $1.1 million to $14.6 million, or an increase of 8%, for the three months ended September 30, 2016, as compared to $13.5 million for the three months ended September 30, 2015. Our lease operating expenses per unit of production decreased 4% to $5.40 per BOE for the three months ended September 30, 2016, as compared to $5.60 per BOE for the three months ended September 30, 2015. The decrease achieved in lease operating expenses on a unit-of-production basis was attributable to several key factors, including (i) decreased field supervisory costs as a number of third-party contractors became full-time employees during the second quarter of 2016, (ii) decreased chemical costs associated with our Eagle Ford operations, (iii) decreased water disposal costs attributable to our own salt water disposal facilities in the Wolf asset area, as well as new water disposal agreements negotiated with third parties, (iv) decreased supervisory and chemical costs associated with our Eagle Ford operations and (v) increased oil equivalent production as compared to the same period in 2015.

Plant and other midstream services operating. Our plant and other midstream services operating expenses remained flat at $1.45 million for the three months ended September 30, 2016, as compared to $1.45 million for the three months ended September 30, 2015.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses decreased by $15.2 million to $30.0 million, or a decrease of 34%, for the three months ended September 30, 2016, as compared to $45.2 million for the three months ended September 30, 2015. On a unit-of-production basis, our depletion, depreciation and amortization expenses decreased to $11.10 per BOE for the three months ended September 30, 2016, or a decrease of 41%, from $18.81 per BOE for the three months ended September 30, 2015. The decrease in both the total and the per-unit-of-production depletion, depreciation and amortization expenses resulted from higher estimated total proved reserves of 101.6 million BOE, or a 17% increase, at September 30, 2016, as compared to estimated total proved reserves of 87.1 million BOE at September 30, 2015, as well as the decrease in unamortized property costs resulting from the full-cost ceiling impairments previously recorded in 2015 and the first and second quarters of 2016. This increase in total proved oil and natural gas reserves was primarily attributable to the continued delineation and development of our acreage in the Delaware Basin.

Full-cost ceiling impairment. At September 30, 2016, we recorded no impairment charge to the net capitalized costs of our oil and natural gas properties. We recorded an impairment charge of $285.7 million to the net capitalized costs of our oil and natural gas properties for the three months ended September 30, 2015.

General and administrative. Our general and administrative expenses increased by $1.0 million to $13.1 million, or an increase of 8%, for the three months ended September 30, 2016, as compared to $12.2 million for the three months ended September 30, 2015. This increase is primarily attributable to increased payroll and related expenses associated with additional employees joining the Company between the respective periods. General and administrative expenses also included non-cash stock-based compensation expense of $3.6 million and $1.8 million for the three months ended September 30, 2016 and 2015, respectively. On a unit-of-production basis, our general and administrative expenses decreased by 4% to $4.86 per BOE for the three months ended September 30, 2016, as compared to $5.05 per BOE for the three months ended September 30, 2015. This decrease in general and administrative expenses on a unit-of-production basis was primarily attributable to the 12% increase in total oil equivalent production between the respective periods.

Net gain (loss) on asset sales and inventory impairment. For the three months ended September 30, 2016, we recognized $1.1 million of the deferred gain on the sale of certain natural gas gathering and processing assets in Loving County, Texas that occurred in the fourth quarter of 2015.

Interest expense. For the three months ended September 30, 2016, we incurred total interest expense of $7.6 million. We capitalized $0.7 million of our interest expense on certain qualifying projects for the three months ended September 30, 2016 and expensed the remaining $6.9 million. For the three months ended September 30, 2015, we incurred total interest expense of $7.8 million. We capitalized $0.5 million of our interest expense on certain qualifying projects for the three months ended September 30, 2015 and expensed the remaining $7.2 million to operations. At September 30, 2016, we had $65.0 million of borrowings outstanding and $0.8 million in letters of credit outstanding under our revolving credit agreement (the “Credit Agreement”) and $400.0 million in outstanding 6.875% senior notes due 2023 (the “Notes”).

Table of Contents

Total income tax benefit. Our deferred tax assets exceed our deferred tax liabilities due to the deferred tax assets generated by the full-cost ceiling impairment charges recorded in prior periods; as a result, we established a valuation allowance against most of the deferred tax assets beginning in the third quarter of 2015. We retain a full valuation allowance at September 30, 2016 due to uncertainties regarding the future realization of our deferred tax assets. The current tax benefit of $1.1 million for the three months ended September 30, 2016 represents a refund due from the Internal Revenue Service. Total income tax expense for the three months ended September 30, 2015 differed from amounts computed by applying the U.S. federal statutory tax rate to loss before income taxes due primarily to the recording of the valuation allowance against the net deferred tax assets, which resulted from the full-cost ceiling impairment recorded in the third quarter of 2015.

Nine Months Ended September 30, 2016 as Compared to Nine Months Ended September 30, 2015

Production taxes, transportation and processing. Our production taxes, transportation and processing expenses increased by approximately $4.1 million to approximately $30.8 million, or an increase of approximately 15%, for the nine months ended September 30, 2016, as compared to $26.7 million for the nine months ended September 30, 2015, in part due to increased oil and natural gas production between the respective periods. On a unit-of-production basis, our production taxes, transportation and processing expenses increased by 8% to $4.16 per BOE for the nine months ended September 30, 2016, as compared to $3.85 per BOE for the nine months ended September 30, 2015. The increase on an absolute basis was primarily attributable to higher natural gas transportation and processing expenses of $19.7 million for the nine months ended September 30, 2016, as compared to natural gas transportation and processing expenses of $16.4 million for the nine months ended September 30, 2015, due to the 7% increase in natural gas production to 22.6 Bcf during the nine months ended September 30, 2016, as compared to 21.1 Bcf of natural gas production for the nine months ended September 30, 2015. This increase of $3.3 million in natural gas transportation and processing expenses was also due to the increase in natural gas production in the Delaware Basin as a percentage of our total natural gas production for the nine months ended September 30, 2016, as compared to the nine months ended September 30, 2015. Natural gas transportation and processing expenses are higher in the Delaware Basin, as compared to the Eagle Ford shale, as the natural gas gathering and processing infrastructure has yet to meet the demand for these services due to the increased drilling activity in the Delaware Basin over the last few years. We have begun to incur lower processing expenses for most of the natural gas produced in our Rustler Breaks asset area in Eddy County, New Mexico due to the start up in late August 2016 of the cryogenic natural gas processing plant we constructed in the Rustler Breaks asset area, and we expect to fully realize the impact of the lower processing expenses once the plant is operational for an entire quarter.

Our production taxes increased for the nine months ended September 30, 2016 by $0.5 million to $10.7 million, as compared to $10.2 million for the nine months ended September 30, 2015, primarily due to the increase in our production from the Delaware Basin as a percentage of our total production between the comparable periods.

Lease operating expenses. Our lease operating expenses increased by approximately $1.2 million, or an increase of 3%, to $41.3 million for the nine months ended September 30, 2016, as compared to $40.1 million for the nine months ended September 30, 2015. Our lease operating expenses per unit of production decreased 4% to $5.56 per BOE for the nine months ended September 30, 2016, as compared to $5.78 per BOE for the nine months ended September 30, 2015. The decrease achieved in lease operating expenses on a unit-of-production basis was attributable to several key factors, including (i) decreased field supervisory costs as a number of third-party contractors became full-time employees during the second quarter of 2016, (ii) decreased chemical costs associated with our Eagle Ford operations, (iii) decreased water disposal costs attributable to our own salt water disposal facilities in the Wolf asset area, as well as new water disposal agreements negotiated with third parties, (iv) decreased supervisory and chemical costs associated with our Eagle Ford operations and (v) increased oil equivalent production as compared to the same period in 2015.

Plant and other midstream services operating. Our plant and other midstream services operating expenses increased by $0.8 million to $3.5 million, or an increase of 28%, for the three months ended September 30, 2016, as compared to $2.8 million for the three months ended September 30, 2015. This increase is primarily attributable to a significant increase in third-party salt water being disposed of at our commercial facilities in the Wolf asset area.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses decreased by $53.3 million to $90.2 million, or a decrease of 37%, for the nine months ended September 30, 2016, as compared to $143.5 million for the nine months ended September 30, 2015. On a unit-of-production basis, our depletion, depreciation and amortization expenses decreased to $12.15 per BOE for the nine months ended September 30, 2016, or a decrease of about 41%, from $20.67 per BOE for the nine months ended September 30, 2015. The decrease in both the total and the per-unit-of-production depletion, depreciation and amortization expenses resulted from higher estimated total proved reserves of 101.6 million BOE, or a 17% increase, at September 30, 2016, as compared to estimated total proved reserves of 87.1 million BOE at September 30, 2015, as well as the decrease in unamortized property costs resulting from the full-cost ceiling impairments previously recorded in 2015 and the first and second quarters of 2016. This increase in total proved oil and natural gas reserves was primarily attributable to the continued delineation and development of our acreage in the Delaware Basin.

Table of Contents

Full-cost ceiling impairment. At September 30, 2016, we recorded no impairment to the net capitalized costs of our oil and natural gas properties. At June 30, 2016, the net capitalized costs of our oil and natural gas properties exceeded the cost center ceiling by $78.2 million. At March 31, 2016, the net capitalized costs of our oil and natural gas properties exceeded the cost center ceiling by $80.5 million. As a result, we recorded an impairment charge of $158.6 million to the net capitalized costs of our oil and natural gas properties for the nine months ended September 30, 2016. At September 30, 2015, the net capitalized costs of our oil and natural gas properties exceeded the cost center ceiling by $285.7 million. At June 30, 2015, the net capitalized costs of our oil and natural gas properties exceeded the cost center ceiling by $229.0 million. At March 31, 2015, the net capitalized costs of our oil and natural gas properties exceeded the cost center ceiling by $67.1 million. As a result, we recorded an impairment charge of $581.9 million to the net capitalized costs of our oil and natural gas properties for the nine months ended September 30, 2015.

General and administrative. Our general and administrative expenses increased by $1.0 million to $39.5 million, or an increase of 3%, for the nine months ended September 30, 2016, as compared to $38.5 million for the nine months ended September 30, 2015. This increase is primarily attributable to increased payroll and related expenses associated with additional employees joining the Company between the respective periods. On a unit-of-production basis, our general and administrative expenses decreased by 4% to $5.32 per BOE for the nine months ended September 30, 2016, as compared to $5.55 per BOE for the nine months ended September 30, 2015. This decrease in general and administrative expenses on a unit-of-production basis was primarily attributable to the 7% increase in total oil equivalent production between the respective periods.

Net gain (loss) on asset sales and inventory impairment. For the nine months ended September 30, 2016, we recognized $3.1 million of the deferred gain on the sale of certain natural gas gathering and processing assets in Loving County, Texas that occurred in the fourth quarter of 2015.

Interest expense. For the nine months ended September 30, 2016, we incurred total interest expense of approximately $23.2 million. We capitalized approximately $2.9 million of our interest expense on certain qualifying projects for the nine months ended September 30, 2016 and expensed the remaining $20.2 million. For the nine months ended September 30, 2015, we incurred total interest expense of approximately $18.0 million. We capitalized approximately $2.9 million of our interest expense on certain qualifying projects for the nine months ended September 30, 2015 and expensed the remaining $15.2 million. The increase in total interest expense was attributable to an increase in the average effective interest rate between comparable periods due primarily to the issuance of the Notes in April 2015. In late April 2015, we used a portion of the net proceeds from the issuance of the Notes and our April 2015 equity offering to repay all outstanding borrowings under our Credit Agreement. At September 30, 2016, we had $65.0 million borrowings outstanding and $0.8 million in letters of credit outstanding under our Credit Agreement and $400.0 million in outstanding Notes.

Total income tax benefit. Our deferred tax assets exceed our deferred tax liabilities due to the deferred tax assets generated by the full-cost ceiling impairment charges recorded in prior periods; as a result, we established a valuation allowance against most of the deferred tax assets beginning in the third quarter of 2015. We retain a full valuation allowance at September 30, 2016 due to uncertainties regarding the future realization of our deferred tax assets. The current tax benefit of $1.1 million for the nine months ended September 30, 2016 represents a refund due from the Internal Revenue Service. Total income tax expense for the nine months ended September 30, 2015 differed from amounts computed by applying the U.S. federal statutory tax rate to loss before income taxes due primarily to the recording of the valuation allowance against the net deferred tax assets which resulted from the full-cost ceiling impairment recorded in the third quarter of 2015.

Liquidity and Capital Resources

Our primary use of capital has been, and we expect will continue to be during the remainder of 2016 and for the foreseeable future, for the acquisition, exploration and development of oil and natural gas properties and for related midstream investments. Excluding any possible significant acquisitions, we expect to fund our capital expenditure requirements through the remainder of 2016 and into 2017 through a combination of cash on hand, operating cash flows and borrowings under our Credit Agreement (assuming availability under our borrowing base). We continually evaluate other capital sources, including borrowings under additional credit arrangements, the sale or joint venture of midstream assets or oil and natural gas producing assets or acreage, particularly in our non-core asset areas, as well as

potential issuances of equity, debt or convertible securities, none of which may be available. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital and to generate operating cash flows.
At September 30, 2016, we had cash totaling $20.6 million and the borrowing base under our Credit Agreement was $300.0 million. At September 30, 2016, we had $65.0 million of borrowings outstanding, $0.8 million in outstanding letters of credit pursuant to our Credit Agreement and $400.0 million of outstanding Notes. At November 1, 2016, we had $95.0 million of borrowings outstanding, $0.8 million in outstanding letters of credit pursuant to our Credit Agreement and $400.0 million of outstanding Notes.
During the fourth quarter of 2016, the lenders under our Credit Agreement completed their review of our estimated total proved oil and natural gas reserves at June 30, 2016, and as a result, in late October 2016, the borrowing base under our Credit Agreement was increased to $400.0 million. This October 2016 redetermination constituted the regularly scheduled November 1 redetermination.

Table of Contents

As of November 1, 2016, we adjusted our anticipated capital expenditures for acquisition, exploration and development activities and related midstream investments in 2016 from $325.0 million to between $425.0 and $450.0 million. We anticipate using such additional capital primarily for strategic acreage and minerals acquisitions and to accelerate a number of new midstream initiatives in the Delaware Basin. We incurred total capital expenditures of approximately $333.5 million during the first nine months of 2016. Our 2016 capital expenditures may be further adjusted as business conditions warrant. While we have budgeted between $425.0 and $450.0 million in capital expenditures for 2016, the amount, timing and allocation of our capital expenditures is largely discretionary and within our control.

As of November 1, 2016, we anticipated investing between $425.0 and $450.0 million in capital for acquisition, exploration and development activities and related midstream investments in 2016 as follows:

| | Amount (in millions) |
|---|---|
| Exploration, development drilling and completion costs, including production facilities and infrastructure | $ 245.0 - 255.0 |
| Midstream activities | 65.0 |
| Leasehold acquisition and 2-D and 3-D seismic data | 110.0 - 125.0 |
| Other | 5.0 |
| Total | $ 425.0 - 450.0 |

The aggregate amount of capital we will expend may fluctuate materially based on market conditions, the actual costs to drill, complete and place on production operated or non-operated wells, our drilling results, the actual costs of our midstream activities, other opportunities that may become available to us and our ability to obtain capital. 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.

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. A significant portion of our anticipated cash flows from operations for the remainder of 2016 is expected to come from producing wells and development activities on currently proved properties in the Wolfcamp and Bone Spring plays in the Delaware Basin, the Eagle Ford shale in South Texas and the Haynesville shale in Louisiana. Our existing wells may not produce at the levels we are forecasting and our exploration and development activities in these areas may not be as successful as we anticipate. Additionally, our anticipated cash flows from operations are based upon current expectations of oil and natural gas prices for the remainder of 2016 and the hedges we currently have in place. We use commodity derivative financial instruments at times 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 November 1, 2016, we had approximately 50% of our anticipated oil production and approximately 70% of our anticipated natural gas production hedged for the remainder of 2016. See Note 8 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for a summary of our open derivative financial instruments at September 30, 2016.

Our unaudited cash flows for the nine months ended September 30, 2016 and 2015 are presented below:

| | Nine Months Ended September 30, | |
|---|---|---|
| (In thousands) | 2016 | 2015 |
| Net cash provided by operating activities | $96,462 | $185,924 |
| Net cash used in investing activities | (297,596 ) | (405,559 ) |
| Net cash provided by financing activities | 204,968 | 225,115 |

| | | |
|---|---|---|
| Net change in cash | $3,834 | $5,480 |
| Adjusted EBITDA[1] | $103,433 | $174,856 |

32

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

Cash Flows Provided by Operating Activities

Net cash provided by operating activities decreased by $89.5 million to $96.5 million for the nine months ended September 30, 2016, as compared to net cash provided by operating activities of $185.9 million for the nine months ended September 30, 2015. Excluding changes in operating assets and liabilities, net cash provided by operating activities decreased by $75.3 million to $85.4 million for the nine months ended September 30, 2016 from $160.7 million for the nine months ended September 30, 2015. This decrease is primarily attributable to the 12% decrease in our oil and natural gas revenues between the respective periods and significantly lower realized gains on derivatives. Changes in our operating assets and liabilities between the nine months ended September 30, 2015 and the nine months ended September 30, 2016 resulted in a net decrease of $14.2 million in net cash provided by operating activities for the nine months ended September 30, 2016.

Our operating cash flows are sensitive to a number of variables, including changes in our production and volatility of oil and natural gas prices between reporting periods. Regional and worldwide economic activity, the actions of OPEC, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of oil and natural gas. These factors are beyond our control and are difficult to predict. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and natural gas liquids prices. In addition, we attempt to avoid long-term service agreements where possible in order to minimize ongoing future commitments.

Cash Flows Used in Investing Activities

Net cash used in investing activities decreased by $108.0 million to $297.6 million for the nine months ended September 30, 2016 from $405.6 million for the nine months ended September 30, 2015. This decrease in net cash used in investing activities for the nine months ended September 30, 2016, as compared to the nine months ended September 30, 2015, is primarily attributable to the following factors: (i) a decrease of $46.8 million in oil and natural gas properties capital expenditures due to our reduced 2016 capital expenditure budget, (ii) a $24.0 million decrease in cash used as a result of expenditures incurred in 2015 in connection with our merger with Harvey E. Yates Company (the "HEYCO Merger") and (iii) a decrease in restricted cash of $42.4 million primarily attributable to the return of cash from the escrow account established to facilitate potential like-kind exchange transactions associated with the sale of certain midstream assets in Loving County, Texas in the fourth quarter of 2015. This decrease was partially offset by the $10.4 million increase in cash used primarily for our midstream investments, including for the construction and installation of the natural gas processing plant and natural gas gathering system in the Rustler Breaks asset area in Eddy County, New Mexico. Cash used for oil and natural gas properties capital expenditures for the nine months ended September 30, 2016 was primarily attributable to our operated drilling and completion activities and the acquisition of additional leasehold and mineral interests in the Delaware Basin. A small portion of our capital expenditures for the nine months ended September 30, 2016 was directed to our participation in non-operated wells, primarily in the Delaware Basin and the Haynesville shale.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities decreased by $20.1 million to $205.0 million for the nine months ended September 30, 2016 from $225.1 million for the nine months ended September 30, 2015. The net cash provided by financing activities for the nine months ended September 30, 2016 was attributable to the net proceeds from our March 2016 equity offering of $142.4 million ($141.5 million net of cost to issue equity) and the proceeds from borrowings under the Credit Agreement of $65.0 million. These net proceeds were partially offset by the taxes paid on net share settlements of stock-based compensation of $1.6 million. The net cash provided by financing activities for the nine months ended September 30, 2015 was primarily attributable to the net proceeds from our April 2015 Notes offering of approximately $391.0 million, the net proceeds from our April 2015 equity offering of $187.5 million and proceeds from borrowings under the Credit Agreement of $125.0 million. These net proceeds were partially offset by (i) the $477.0 million repayment of the borrowings outstanding under our Credit Agreement and debt obligations assumed in the HEYCO Merger and (ii) the taxes paid on net share settlements of stock-based compensation of $1.6 million.

See Note 5 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for a summary of our debt, including our Credit Agreement and the Notes.

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-

Table of Contents

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (In thousands) | 2016 | 2015 | 2016 | 2015 |
| Unaudited Adjusted EBITDA Reconciliation to Net Income (Loss): | | | | |
| Net income (loss) attributable to Matador Resources Company shareholders | $11,931 | $(242,059) | $(201,575) | $(449,384) |
| Interest expense | 6,880 | 7,229 | 20,244 | 15,168 |
| Total income tax benefit | (1,141) | (33,305) | (1,141) | (149,045) |
| Depletion, depreciation and amortization | 30,015 | 45,237 | 90,185 | 143,477 |
| Accretion of asset retirement obligations | 276 | 182 | 828 | 427 |
| Full-cost ceiling impairment | — | 285,721 | 158,633 | 581,874 |
| Unrealized (gain) loss on derivatives | (3,203) | (6,733) | 30,261 | 25,356 |
| Stock-based compensation expense | 3,584 | 1,755 | 9,138 | 6,886 |
| Net (gain) loss on asset sales and inventory impairment | (1,073) | — | (3,140) | 97 |
| Adjusted EBITDA | $47,269 | $58,027 | $103,433 | $174,856 |

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (In thousands) | 2016 | 2015 | 2016 | 2015 |
| Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities: | | | | |
| Net cash provided by operating activities | $46,862 | $72,535 | $96,462 | $185,924 |
| Net change in operating assets and liabilities | (4,909) | (20,846) | (11,024) | (25,234) |
| Interest expense, net of non-cash portion | 6,573 | 6,678 | 19,345 | 14,617 |
| Current income tax benefit | (1,141) | (295) | (1,141) | (295) |
| Net income attributable to non-controlling interest in subsidiaries | (116) | (45) | (209) | (156) |
| Adjusted EBITDA | $47,269 | $58,027 | $103,433 | $174,856 |

The net income attributable to Matador Resources Company shareholders increased by $254.0 million to net income of $11.9 million for the three months ended September 30, 2016, as compared to a net loss of $242.1 million for the three months ended September 30, 2015. This increase in the net income for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015 is primarily attributable to (i) the decrease in the full-cost ceiling impairment, (ii) the decrease in depletion, depreciation and amortization expense and (iii) the increase in oil and natural gas revenues, which was partially offset by (x) the decrease in the realized gain on derivatives and (y) the decrease in the deferred income tax benefit.

The net loss attributable to Matador Resources Company shareholders decreased by $247.8 million to $201.6 million, or a decrease of 55%, for the nine months ended September 30, 2016, as compared to a net loss of $449.4 million for the nine months ended September 30, 2015. This decrease in the net loss for the nine months ended September 30, 2016, as compared to

Table of Contents

the nine months ended September 30, 2015 is primarily attributable to (i) the decrease in the full-cost ceiling impairment and (ii) the decrease in depletion, depreciation and amortization expense, which was partially offset by (w) the decrease in oil and natural gas revenues, (x) the decrease in the realized gain on derivatives, (y) the increase in interest expense and (z) the decrease in the deferred income tax benefit.

Our Adjusted EBITDA decreased by $10.8 million to $47.3 million, or a decrease of 19%, for the three months ended September 30, 2016, as compared to $58.0 million for the three months ended September 30, 2015. This decrease in our Adjusted EBITDA is primarily attributable to the decrease in the realized gain on derivatives, but was partially mitigated by the increase in oil and natural gas revenues for the three months ended September 30, 2016, as compared to the three months ended September 30, 2015.

Our Adjusted EBITDA decreased by $71.4 million to $103.4 million, or a decrease of 41%, for the nine months ended September 30, 2016, as compared to $174.9 million for the nine months ended September 30, 2015. This decrease in our Adjusted EBITDA is primarily attributable to the decrease in the realized gains on derivatives and the decrease in oil and natural gas revenues resulting from lower commodity prices for the nine months ended September 30, 2016, as compared to the nine months ended September 30, 2015.

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 September 30, 2016, 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 10 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding our off-balance sheet arrangements. Such information is incorporated herein by reference.

Obligations and Commitments

We had the following material contractual obligations and commitments at September 30, 2016:

| | 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)] | $65,821 | $821 | $— | $65,000 | $— |
| Senior unsecured notes[(2)] | 400,000 | — | — | — | 400,000 |
| Office leases | 25,663 | 2,418 | 5,006 | 5,239 | 13,000 |
| Non-operated drilling commitments[(3)] | 11,183 | 11,183 | — | — | — |
| Drilling rig contracts[(4)] | 42,952 | 22,674 | 20,278 | — | — |
| Asset retirement obligations | 19,481 | 29 | 1,863 | 4,077 | 13,512 |
| Natural gas processing and transportation agreements[(5)] | 13,606 | 1,648 | 11,958 | — | — |
| Natural gas plant engineering, procurement, construction and installation contract[(6)] | 4,236 | 4,236 | — | — | — |
| Total contractual cash obligations | $582,942 | $43,009 | $39,105 | $74,316 | $426,512 |

(1) At September 30, 2016, we had $65.0 million of borrowings outstanding under our Credit Agreement and approximately $0.8 million in outstanding letters of credit issued pursuant to the Credit Agreement. The Credit Agreement matures in October 2020.

(2) These amounts represent principal maturities only.

(3) At September 30, 2016, we had outstanding commitments to participate in the drilling and completion of various non-operated wells. Our working interests in these wells are typically small, and several of these wells were in progress at September 30, 2016. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of $11.2 million at September 30, 2016, which we expect to incur within the next few months.

Table of Contents

(4) We do not own or operate our own drilling rigs, but instead enter into contracts with third parties for such rigs. See Note 10 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding our contractual commitments.

(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. Effective October 1, 2015, we entered into a 15-year fixed-fee natural gas gathering and processing agreement for a significant portion of our operated natural gas production in Loving County, Texas. See Note 10 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding our contractual commitments.

(6) In 2015, we entered into an agreement with a third party for the engineering, procurement, construction and installation of a natural gas processing plant in the Rustler Breaks asset area in Eddy County, New Mexico. See Note 10 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding our contractual commitments.

General Outlook and Trends

For the three months ended September 30, 2016, oil prices ranged from a low of approximately $39.51 per Bbl in early August to a high of approximately $48.99 per Bbl in early July, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. We realized an average oil price of $42.57 per Bbl ($43.18 per Bbl including realized gains from oil derivatives) for our oil production for the three months ended September 30, 2016, as compared to $43.21 per Bbl ($57.90 per Bbl including realized gains from oil derivatives) for the three months ended September 30, 2015. Subsequent to September 30, 2016, oil prices have decreased and, at November 1, 2016, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date closed at $46.67 per Bbl, as compared to $46.14 per Bbl at November 2, 2015.

For the three months ended September 30, 2016, natural gas prices ranged from a high of $3.06 per MMBtu in late September to a low of $2.55 per MMBtu in mid-August, 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 $3.08 per Mcf ($3.08 per Mcf including realized gains from natural gas derivatives) for our natural gas production for the three months ended September 30, 2016, as compared to $2.90 per Mcf ($3.28 per Mcf including aggregate realized gains from natural gas and NGL derivatives) for the three months ended September 30, 2015. 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 September 30, 2016, natural gas prices have been volatile, and at November 1, 2016, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date closed at $2.90 per MMBtu, as compared to $2.26 per MMBtu at November 2, 2015.

The prices we receive for oil, natural gas and natural gas liquids heavily influence our revenue, profitability, cash flow available for capital expenditures, access to capital and future rate of growth. Oil, natural gas and natural gas liquids are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil, natural gas and natural gas liquids have been volatile and these markets will likely continue to be volatile in the future. Declines in oil, natural gas or natural gas liquids prices not only reduce our revenues, but could also reduce the amount of oil, natural gas and natural gas liquids we can produce economically. We are uncertain when, or if, oil, natural gas and natural gas liquids prices may rise from their current levels, and in fact, oil, natural gas and natural gas liquids prices may decrease in future periods.

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. We expect our realized gains from derivatives, if any, to be less for the remainder of 2016, as compared to comparable periods in 2015, especially from our oil derivative contracts.

Like other oil and natural gas producing companies, our properties are subject to natural production declines. By their nature, our oil and natural gas wells experience rapid initial production declines. We attempt to overcome these production declines by drilling to develop and identify additional reserves, by exploring for new sources of reserves and, at times, by acquisitions. During times of severe oil, natural gas and natural gas liquids price declines, however, drilling additional oil or natural gas wells may not be economical, and we may find it necessary to reduce capital expenditures and curtail drilling operations in order to preserve liquidity. A material reduction in capital expenditures and drilling activities could materially impact our production volumes, revenues, reserves, cash flows and availability under our Credit Agreement.

We strive to focus our efforts on increasing oil and natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our ability to find and develop sufficient quantities of oil and natural gas reserves at economical costs is critical to our long-term success. Future finding and development costs are subject to changes in the costs of acquiring, drilling and completing our prospects.

Table of Contents

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, 2015, 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 that is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially “costless” to us. In the case of a costless collar, the put option and the call option have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over a specified time, providing downside price protection.

We record all derivative financial instruments at fair value. The fair value of our derivative financial instruments is determined using industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. At September 30, 2016, Comerica Bank, The Bank of Nova Scotia, BMO Harris Financing, Inc. (Bank of Montreal) and SunTrust Bank (or affiliates thereof) were the counterparties for all of our derivative instruments. We have evaluated the credit standing of the counterparties in determining the fair value of our derivative financial instruments. See Note 8 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for a summary of our open derivative financial instruments at September 30, 2016. 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 Exchange Act) under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the Company’s disclosure controls and procedures were effective as of September 30, 2016 to ensure that (i) information required to be disclosed in the reports the Company files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and that (ii) information required to be disclosed under the Exchange Act is accumulated and communicated to the Company’s management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2016, 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 several lawsuits encountered in the ordinary course of business. While the ultimate outcome and impact to us cannot be predicted with certainty, in the opinion of management, it is remote that these lawsuits will have a material adverse impact on our financial condition, 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 2. Unregistered Sales of Equity Securities and Use of Proceeds

During the quarter ended September 30, 2016, the Company re-acquired shares of common stock from certain employees in order to satisfy the employees' tax liability in connection with the vesting of restricted stock.

| Period | Total Number of Shares Purchased (1) | Average Price Paid Per Share | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | Maximum Number of Shares that May Yet Be Purchased under the Plans or Programs |
|---|---|---|---|---|
| July 1, 2016 to July 31, 2016 | 1,972 | $ 20.68 | — | — |
| August 1, 2016 to August 31, 2016 | 16,883 | 21.61 | — | — |
| September 1, 2016 to September 30, 2016 | 1,283 | 22.99 | — | — |
| Total | 20,138 | $ 21.61 | — | — |

(1) The shares were not re-acquired pursuant to any repurchase plan or program.

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: November 4, 2016 By: | /s/ Joseph Wm. Foran |
| | Joseph Wm. Foran |
| | Chairman and Chief Executive Officer |
| Date: November 4, 2016 By: | /s/ David E. Lancaster |
| | David E. Lancaster |
| | Executive Vice President and Chief Financial Officer |

Table of Contents

EXHIBIT INDEX

| Exhibit Number | Description |
|---|---|
| 3.1 | Certificate of Merger between Matador Resources Company (now known as MRC Energy Company) and Matador Merger Co. (incorporated by reference to Exhibit 3.4 to our Registration Statement on Form S-1 filed on August 12, 2011). |
| 3.2 | Amended and Restated Certificate of Formation of Matador Resources Company (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on February 13, 2012). |
| 3.3 | Certificate of Amendment to the Amended and Restated Certificate of Formation of Matador Resources Company (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2015). |
| 3.4 | Amended and Restated Bylaws of Matador Resources Company, as amended (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on February 25, 2016). |
| 3.5 | Statement of Resolutions for Series A Convertible Preferred Stock (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on March 2, 2015). |
| 10.1 | Eighth Amendment to Third Amended and Restated Credit Agreement, dated as of October 31, 2016, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on November 2, 2016). |
| 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 (furnished 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 (furnished herewith). |
| 99.1 | Audit report of Netherland, Sewell & Associates, Inc. (filed herewith). |
| 101 | The following financial information from Matador Resources Company’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2016 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). |