Gastar Exploration Inc.
Form 10-Q
August 06, 2015
Table of Contents

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

FORM 10-Q

---

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED June 30, 2015
OR
o 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: 001-35211

GASTAR EXPLORATION INC.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	38-3531640 (I.R.S. Employer Identification No.)
1331 Lamar Street, Suite 650 Houston, Texas (Address of principal executive offices)	77010 (Zip Code)

(713) 739-1800
(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.

Yes ý No o

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).

Yes ý No o

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No ý

The total number of outstanding common shares, $0.001 par value per share, as of August 3, 2015 was 80,142,118.

Table of Contents

GASTAR EXPLORATION INC.
QUARTERLY REPORT ON FORM 10-Q
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2015
TABLE OF CONTENTS

Table of Contents

On November 14, 2013, Gastar Exploration Ltd., an Alberta, Canada corporation, changed its jurisdiction of incorporation to the State of Delaware and changed its name to "Gastar Exploration, Inc." On January 31, 2014, Gastar Exploration, Inc. merged with and into Gastar Exploration USA, Inc., its direct subsidiary, as part of a reorganization to eliminate Gastar Exploration, Inc.'s holding company corporate structure. Pursuant to the merger agreement, shares of Gastar Exploration, Inc.'s common stock were converted into an equal number of shares of common stock of Gastar Exploration USA, Inc., and Gastar Exploration USA, Inc. changed its name to "Gastar Exploration Inc." Gastar Exploration Inc. owns and continues to conduct Gastar Exploration, Inc.'s business in substantially the same manner as was being conducted prior to the merger.

Unless otherwise indicated or required by the context, (i) for any date or period prior to the January 31, 2014 merger described above, "Gastar," the "Company," "we," "us," "our" and similar terms refer collectively to Gastar Exploration, Inc.(formerly known as Gastar Exploration Ltd.) and its subsidiaries, including Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.), and for any date or period after January 31, 2014, such terms refer collectively to Gastar Exploration Inc. and its subsidiaries, (ii) "Gastar USA" refers to Gastar Exploration USA, Inc., which until January 31, 2014 was a first-tier subsidiary of Gastar Exploration, Inc. and its primary operating company, (iii) "Parent" refers to Gastar Exploration, Inc., (iv) all dollar amounts appearing in this Form 10-Q are stated in United States dollars ("U.S. dollars") unless otherwise noted and (v) all financial data included in this Form 10-Q have been prepared in accordance with generally accepted accounting principles in the United States of America ("U.S. GAAP").

General information about us can be found on our website at www.gastar.com. The information available on or through our website, or about us on any other website, is neither incorporated into, nor part of, this report. Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings that we make with the U.S. Securities and Exchange Commission ("SEC"), as well as any amendments and exhibits to those reports, will be available free of charge through our website as soon as reasonably practicable after we file or furnish them to the SEC. Information is also available on the SEC website at www.sec.gov for our U.S. filings.

Table of Contents

Glossary of Terms

AMI	Area of mutual interest, an agreed designated geographic area where joint venturers or other industry partners have a right of participation in acquisitions and operations
Bbl	Barrel of oil, condensate or NGLs
Bbl/d	Barrels of oil, condensate or NGLs per day
Bcf	One billion cubic feet of natural gas
Bcfe	One billion cubic feet of natural gas equivalent, calculated by converting liquids volumes on the basis of 1/6th of a barrel of oil, condensate or NGLs per Mcf
Boe	One barrel of oil equivalent determined using the ratio of six thousand cubic feet of natural gas to one barrel of oil, condensate or NGLs
Boe/d	Barrels of oil equivalent per day
Btu	British thermal unit, typically used in measuring natural gas energy content
CRP	Central receipt point
FASB	Financial Accounting Standards Board
Gross acres	Refers to acres in which we own a working interest
Gross wells	Refers to wells in which we have a working interest
MBbl	One thousand barrels of oil, condensate or NGLs
MBbl/d	One thousand barrels of oil, condensate or NGLs per day
MBoe	One thousand barrels of oil equivalent, calculated by converting natural gas volumes on the basis of 6 Mcf of natural gas per barrel
MBoe/d	One thousand barrels of oil equivalent per day
Mcf	One thousand cubic feet of natural gas
Mcf/d	One thousand cubic feet of natural gas per day
Mcfe	One thousand cubic feet of natural gas equivalent, calculated by converting liquids volumes on the basis of 1/6th of a barrel of oil, condensate or NGLs per Mcf
MMBtu/d	One million British thermal units per day
MMcf	One million cubic feet of natural gas

MMcf/d	One million cubic feet of natural gas per day
MMcfe	One million cubic feet of natural gas equivalent, calculated by converting liquids volumes on the basis of 1/6th of a barrel of oil, condensate or NGLs per Mcf
MMcfe/d	One million cubic feet of natural gas equivalent per day
Net acres	Refers to our proportionate interest in acreage resulting from our ownership in gross acreage
Net wells	Refers to gross wells multiplied by our working interest in such wells
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange
PBU	Performance based unit comprising one of our compensation plan awards
psi	Pounds per square inch
U.S.	United States of America
U.S. GAAP	Accounting principles generally accepted in the United States of America

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements
GASTAR EXPLORATION INC.
CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2015 (Unaudited)	December 31, 2014
	(in thousands, except share data)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$9,378	$ 11,008
Accounts receivable, net of allowance for doubtful accounts of $0, respectively	16,431	30,841
Commodity derivative contracts	13,159	19,687
Prepaid expenses	686	2,083
Total current assets	39,654	63,619
PROPERTY, PLANT AND EQUIPMENT:		
Oil and natural gas properties, full cost method of accounting:		
Unproved properties, excluded from amortization	123,162	128,274
Proved properties	1,208,229	1,124,367
Total oil and natural gas properties	1,331,391	1,252,641
Furniture and equipment	3,055	3,010
Total property, plant and equipment	1,334,446	1,255,651
Accumulated depreciation, depletion and amortization	(694,054)	(563,351)
Total property, plant and equipment, net	640,392	692,300
OTHER ASSETS:		
Commodity derivative contracts	9,996	7,815
Deferred charges, net	2,889	2,586
Advances to operators and other assets	795	9,474
Total other assets	13,680	19,875
TOTAL ASSETS	$693,726	$ 775,794
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$13,333	$ 28,843
Revenue payable	6,770	9,122
Accrued interest	3,553	3,528
Accrued drilling and operating costs	6,351	5,977
Advances from non-operators	—	1,820
Commodity derivative contracts	166	—
Commodity derivative premium payable	1,515	2,481
Asset retirement obligation	86	82
Other accrued liabilities	9,251	3,175
Total current liabilities	41,025	55,028
LONG-TERM LIABILITIES:		
Long-term debt	411,545	360,303
Commodity derivative contracts	616	—
Commodity derivative premium payable	4,051	4,702
Asset retirement obligation	5,873	5,475

Total long-term liabilities	422,085	370,480
Commitments and contingencies (Note 11)		
STOCKHOLDERS' EQUITY:		
Preferred stock, 40,000,000 shares authorized		
Series A Preferred stock, par value $0.01 per share; 10,000,000 shares designated; 4,045,000 shares issued and outstanding at June 30, 2015 and December 31, 2014, respectively, with liquidation preference of $25.00 per share	41	41
Series B Preferred stock, par value $0.01 per share; 10,000,000 shares designated; 2,140,000 shares issued and outstanding at June 30, 2015 and December 31, 2014, respectively, with liquidation preference of $25.00 per share	21	21
Common stock, par value $0.001 per share; 275,000,000 shares authorized; 80,144,934 and 78,632,810 shares issued and outstanding at June 30, 2015 and December 31, 2014, respectively	78	78
Additional paid-in capital	569,788	568,440
Accumulated deficit	(339,312)	(218,294)
Total stockholders' equity	230,616	350,286
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$693,726	$ 775,794

5

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

Table of Contents

GASTAR EXPLORATION INC.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	For the Three Months Ended June 30, 2015	For the Three Months Ended June 30, 2014	For the Six Months Ended June 30, 2015	For the Six Months Ended June 30, 2014
	(in thousands, except share and per share data)			
REVENUES:				
Oil and condensate	$17,584	$22,342	$32,937	$39,120
Natural gas	3,950	17,559	10,650	32,978
NGLs	2,184	4,906	4,280	11,550
Total oil, condensate, natural gas and NGLs revenues	23,718	44,807	47,867	83,648
(Loss) gain on commodity derivatives contracts	(1,790)	(8,910)	8,433	(15,424)
Total revenues	21,928	35,897	56,300	68,224
EXPENSES:				
Production taxes	822	2,037	1,662	3,931
Lease operating expenses	7,242	4,877	13,261	8,921
Transportation, treating and gathering	542	2,146	1,039	2,771
Depreciation, depletion and amortization	16,080	10,280	30,551	22,662
Impairment of oil and natural gas properties	100,152	—	100,152	—
Accretion of asset retirement obligation	131	125	256	247
General and administrative expense	4,421	3,893	8,669	8,656
Total expenses	129,390	23,358	155,590	47,188
(LOSS) INCOME FROM OPERATIONS	(107,462)	12,539	(99,290)	21,036
OTHER INCOME (EXPENSE):				
Interest expense	(6,936)	(6,912)	(14,497)	(13,803)
Investment income and other	3	4	6	11
Foreign transaction loss	—	(4)	—	(6)
(LOSS) INCOME BEFORE PROVISION FOR INCOME TAXES	(114,395)	5,627	(113,781)	7,238
Provision for income taxes	—	—	—	—
NET (LOSS) INCOME	(114,395)	5,627	(113,781)	7,238
Dividends on preferred stock	(3,619)	(3,611)	(7,237)	(7,187)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS	$(118,014)	$2,016	$(121,018)	$51
NET (LOSS) INCOME PER SHARE OF COMMON STOCK ATTRIBUTABLE TO COMMON STOCKHOLDERS:				
Basic	$(1.52)	$0.03	$(1.56)	$—
Diluted	$(1.52)	$0.03	$(1.56)	$—
WEIGHTED AVERAGE SHARES OF COMMON STOCK OUTSTANDING:				
Basic	77,611,167	58,702,982	77,364,368	58,462,124
Diluted	77,611,167	61,922,874	77,364,368	61,674,267

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

GASTAR EXPLORATION INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the Six Months Ended June 30,	
	2015	2014
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net (loss) income	$(113,781)	$7,238
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depreciation, depletion and amortization	30,551	22,662
Impairment of oil and natural gas properties	100,152	—
Stock-based compensation	2,773	2,532
Mark to market of commodity derivatives contracts:		
Total (gain) loss on commodity derivatives contracts	(8,433)	15,424
Cash settlements of matured commodity derivatives contracts, net	11,408	(6,061)
Cash premiums paid for commodity derivatives contracts	(45)	(155)
Amortization of deferred financing costs	1,736	1,491
Accretion of asset retirement obligation	256	247
Settlement of asset retirement obligation	(80)	(546)
Changes in operating assets and liabilities:		
Accounts receivable	15,887	(2,827)
Prepaid expenses	1,397	112
Accounts payable and accrued liabilities	(4,806)	9,649
Net cash provided by operating activities	37,015	49,766
CASH FLOWS FROM INVESTING ACTIVITIES:		
Development and purchase of oil and natural gas properties	(84,724)	(55,295)
Advances to operators	(1,225)	(20,657)
Acquisition of oil and natural gas properties - refund	—	4,209
Proceeds from sale of oil and natural gas properties	2,008	3,077
Deposit for sale of oil and natural gas properties	6,620	—
(Payments to) proceeds from non-operators	(1,820)	526
Purchase of furniture and equipment	(45)	(158)
Net cash used in investing activities	(79,186)	(68,298)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from revolving credit facility	55,000	35,000
Repayment of revolving credit facility	(5,000)	(15,000)
Proceeds from issuance of preferred stock, net of issuance costs	—	2,064
Dividends on preferred stock	(7,237)	(7,187)
Deferred financing charges	(797)	(319)
Tax withholding related to restricted stock and performance based unit award vestings	(1,425)	(3,656)
Net cash provided by financing activities	40,541	10,902
NET DECREASE IN CASH AND CASH EQUIVALENTS	(1,630)	(7,630)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	11,008	32,393
CASH AND CASH EQUIVALENTS, END OF PERIOD	$9,378	$24,763

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

8

Table of Contents

GASTAR EXPLORATION INC.
NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Description of Business

Gastar Exploration Inc. (the “Company” or “Gastar,” and before January 31, 2014, “Gastar USA”) is an independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and NGLs in the U.S. Gastar’s principal business activities include the identification, acquisition, and subsequent exploration and development of oil and natural gas properties with an emphasis on unconventional reserves, such as shale resource plays. In Oklahoma, Gastar is developing the primarily oil-bearing reservoirs of the Hunton Limestone horizontal oil play and expects to test other prospective formations on the same acreage, including the Meramec Shale (middle Mississippi Lime) and the Woodford Shale, which Gastar refers to as the STACK Play. In West Virginia, Gastar is developing liquids-rich natural gas in the Marcellus Shale and has drilled and completed its first two successful dry gas Utica Shale/Point Pleasant wells on its acreage.

All references to “Gastar,” the “Company” and similar terms refer collectively to Gastar Exploration Inc. Unless otherwise stated or the context requires otherwise, all references in these notes to “Gastar USA” refer collectively to Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.) and its wholly-owned subsidiaries and all references to “Parent” refer solely to Gastar Exploration, Inc. (formerly known as Gastar Exploration Ltd.).

2. Summary of Significant Accounting Policies

The accounting policies followed by the Company are set forth in the notes to the Company’s audited consolidated financial statements included in its Annual Report on Form 10-K for the year ended December 31, 2014 (the “2014 Form 10-K”) filed with the SEC. Please refer to the notes to the consolidated financial statements included in the 2014 Form 10-K for additional details of the Company’s financial condition, results of operations and cash flows. No material item included in those notes has changed except as a result of normal transactions in the interim or as disclosed within this report.

The unaudited interim condensed consolidated financial statements of the Company included herein are stated in U.S. dollars and were prepared from the records of the Company by management in accordance with U.S. GAAP applicable to interim financial statements and reflect all normal and recurring adjustments, which are, in the opinion of management, necessary to provide a fair presentation of the results of operations and financial position for the interim periods. Such financial statements conform to the presentation reflected in the 2014 Form 10-K. The current interim period reported herein should be read in conjunction with the financial statements and accompanying notes, including Item 8. “Financial Statements and Supplementary Data, Note 2 – Summary of Significant Accounting Policies,” included in the 2014 Form 10-K.

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and 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. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and natural gas reserve quantities and the related present value of estimated future net cash flows.

The unaudited interim condensed consolidated financial statements of the Company include the consolidated accounts of all of its subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation. Certain reclassifications of prior year balances have been made to conform to the current year presentation; these reclassifications have no impact on net income (loss).

The results of operations for the three and six months ended June 30, 2015 are not necessarily indicative of the results that may be expected for the year ending December 31, 2015. In preparing these financial statements, the Company has evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued and has disclosed certain subsequent events in these condensed consolidated financial statements, as appropriate.

Recent Accounting Developments

The following recently issued accounting pronouncement may impact the Company in future periods:

Debt Issuance Costs. In April 2015, the FASB issued updated guidance regarding simplification of the presentation of debt issuance costs. The updated guidance requires debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability instead of being presented as an asset. Debt disclosures will include the face amount of the debt liability and the effective interest rate. The update requires retrospective application and represents a change in accounting principle. The update is effective for fiscal years beginning after December 15, 2015. Early adoption is permitted for financial statements that have not been previously issued. The Company does not expect the adoption of this guidance to have a material impact on its consolidated financial statements.

Table of Contents

Going Concern. In August 2014, the FASB issued updated guidance related to determining whether substantial doubt exists about an entity's ability to continue as a going concern. The amendment provides guidance for determining whether conditions or events give rise to substantial doubt that an entity has the ability to continue as a going concern within one year following issuance of the financial statements, and requires specific disclosures regarding the conditions or events leading to substantial doubt. The updated guidance is effective for annual reporting periods and interim periods within those annual periods beginning after December 15, 2016. Earlier adoption is permitted. The Company does not expect the adoption of this guidance to have a material impact on its consolidated financial statements.

Revenue Recognition. In May 2014, the FASB issued an amendment to previously issued guidance regarding the recognition of revenue. The FASB and the International Accounting Standards Board initiated a joint project to clarify the principles for recognizing revenue and to develop a common standard that would (i) remove inconsistencies and weaknesses in revenue requirements, (ii) provide a more robust framework for addressing revenue issues, (iii) improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets, (iv) provide more useful information to users of financial statements through improved disclosure requirements and (v) simplify the preparation of financial statements by reducing the number of requirements to which an entity must refer. The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this core principle, an entity should apply the following steps: (1) identify the contract(s) with the customer; (2) identify the performance obligations in the contract; (3) determine the transaction price; (4) allocate the transaction price to the performance obligations in the contract; and (5) recognize revenue when (or as) the entity satisfies a performance obligation. This guidance supersedes prior revenue recognition requirements and most industry-specific guidance throughout the FASB Accounting Standards Codification. This guidance is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. In April 2015, the FASB proposed to delay the effective date one year, beginning in fiscal year 2018. The proposal will be subject to the FASB's due process requirement, which includes a period for public comments. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, results of operations or cash flows and does not expect the adoption of this guidance to materially impact its operating results, financial position or cash flows.

3. Property, Plant and Equipment

The amount capitalized as oil and natural gas properties was incurred for the purchase and development of various properties in the U.S., located in the states of Oklahoma, Pennsylvania and West Virginia.

The following table summarizes the components of unproved properties excluded from amortization at the dates indicated:

	June 30, 2015	December 31, 2014
	(in thousands)	
Unproved properties, excluded from amortization:		
Drilling in progress costs	$14,895	$29,193
Acreage acquisition costs	98,278	91,362
Capitalized interest	9,989	7,719
Total unproved properties excluded from amortization	$123,162	$128,274

The full cost method of accounting for oil and natural gas properties requires a quarterly calculation of a limitation on capitalized costs, often referred to as a full cost ceiling calculation. The ceiling is the present value (discounted at 10% per annum) of estimated future cash flow from proved oil, condensate, natural gas and NGLs reserves reduced by future operating expenses, development expenditures, abandonment costs (net of salvage) to the extent not included in oil and natural gas properties pursuant to authoritative guidance and estimated future income taxes thereon. To the extent that the Company's capitalized costs (net of accumulated depletion and deferred taxes) exceed the ceiling at the end of the reported period, the excess must be written off to expense for such period. Once incurred, this impairment of oil and natural gas properties is not reversible at a later date even if oil and natural gas prices increase. The ceiling calculation is determined using a mandatory trailing 12-month unweighted arithmetic average of the first-day-of-the-month commodities pricing and costs in effect at the end of the period, each of which are held constant indefinitely (absent specific contracts with respect to future prices and costs) with respect to valuing future net cash flows from proved reserves for this purpose. The 12-month unweighted arithmetic average of the first-day-of-the-month commodities prices are adjusted for basis and quality differentials in determining the present value of the proved reserves. The table below sets forth relevant pricing assumptions utilized in the quarterly ceiling test computations for the respective periods noted before adjustment for basis and quality differentials:

Table of Contents

	2015 Total Impairment	June 30	March 31
Henry Hub natural gas price (per MMBtu)(1)		$3.39	$3.88
West Texas Intermediate oil price (per Bbl)(1)		$71.68	$82.72
Impairment recorded (pre-tax) (in thousands)	$100,152	$100,152	$—

	2014 Total Impairment	June 30	March 31
Henry Hub natural gas price (per MMBtu)(1)		$4.10	$3.99
West Texas Intermediate oil price (per Bbl)(1)		$100.11	$98.30
Impairment recorded (pre-tax) (in thousands)	$—	$—	$—

(1) For the respective periods, oil and natural gas prices are calculated using the trailing 12-month unweighted arithmetic average of the first-day-of-the-month prices based on Henry Hub spot natural gas prices and West Texas Intermediate spot oil prices.

Future declines in the trailing 12-month average of oil, condensate, natural gas and NGLs prices will likely result in the recognition of significant additional ceiling impairments in 2015.

Mid-Continent Divestiture

On July 6, 2015, the Company sold to an undisclosed private third party certain non-core assets comprised of 38 gross (16.7 net) wells producing approximately net 170 Boe/d (41% oil) for the three months ended March 31, 2015 and approximately 29,500 gross (19,200 net) acres in Kingfisher County, Oklahoma for approximately $46.1 million, reflecting an effective date of April 1, 2015 and customary closing adjustments. Of the total purchase price, $6.6 million was deposited during the second quarter of 2015 and accounted for in other liabilities at June 30, 2015. The sale will be reflected as a reduction to the full cost pool and the Company will not record a gain or loss related to the divestiture as it is not significant to the full cost pool.

Atinum Joint Venture

In September 2010, the Company entered into a joint venture (the “Atinum Joint Venture”) pursuant to which the Company ultimately assigned to an affiliate of Atinum Partners Co., Ltd. (“Atinum”), for total consideration of $70.0 million, a 50% working interest in certain undeveloped acreage and wells. Effective June 30, 2011, an area of mutual interest (“AMI”) was established for additional acreage acquisitions in Ohio, New York, Pennsylvania and West Virginia, excluding the counties of Pendleton, Pocahontas, Preston, Randolph and Tucker, West Virginia. Within this AMI, the Company acts as operator and is obligated to offer any future lease acquisitions within the AMI to Atinum on a 50/50 basis, and Atinum will pay the Company on an annual basis an amount equal to 10% of lease bonuses and third party leasing costs up to $20.0 million and 5% of such costs on activities above $20.0 million.

The Atinum Joint Venture pursued an initial three-year development program that called for the partners to drill a minimum of 60 operated horizontal wells by year-end 2013. Due to natural gas price declines, Atinum and the Company agreed to reduce the minimum wells to be drilled requirements from the originally agreed upon 60 gross wells to 51 gross wells. At June 30, 2015, 74 gross operated horizontal Marcellus Shale wells and two gross operated horizontal Utica Shale/Point Pleasant well were capable of production under the Atinum Joint Venture. The Atinum Joint Venture Agreement expires on November 1, 2015.

4. Long-Term Debt

Second Amended and Restated Revolving Credit Facility

On June 7, 2013, the Company entered into the Second Amended and Restated Credit Agreement among the Company, Wells Fargo Bank, National Association, as Administrative Agent, Collateral Agent, Swing Line Lender and Issuing Lender and the lenders named therein (the “Revolving Credit Facility”). At the Company's election, borrowings bear interest at the reference rate or the Eurodollar rate plus an applicable margin. The reference rate is the greater of (i) the rate of interest publicly announced by the administrative agent, (ii) the federal funds rate plus 50 basis points and (iii) LIBOR plus 1.0%. The applicable interest rate margin varies from 1.0% to 2.0% in the case of borrowings based on the reference rate and from 2.0% to 3.0% in the case of borrowings based on the Eurodollar rate, depending on the utilization percentage in relation to the

Table of Contents

borrowing base and subject to adjustments based on the Company's leverage ratio. An annual commitment fee of 0.5% is payable quarterly on the unutilized balance of the borrowing base. The Revolving Credit Facility has a scheduled maturity of November 14, 2017.

The Revolving Credit Facility will be guaranteed by all of the Company's future domestic subsidiaries formed during the term of the Revolving Credit Facility. Borrowings and related guarantees are secured by a first priority lien on certain domestic oil and natural gas properties currently owned by or later acquired by the Company and its subsidiaries, excluding de minimis value properties as determined by the lender. The Revolving Credit Facility is secured by a first priority pledge of the capital stock of each domestic subsidiary, a first priority interest on all accounts receivable, notes receivable, inventory, contract rights, general intangibles and material property of the issuer and 65% of the stock of any foreign subsidiary of the Company.

The Revolving Credit Facility contains various covenants, including, among others:

- Restrictions on liens, incurrence of other indebtedness without lenders' consent and common stock dividends and other restricted payments;
- Maintenance of a minimum consolidated current ratio as of the end of each quarter of not less than 1.0 to 1.0, as adjusted;
- Maintenance of a maximum ratio of net indebtedness to EBITDA of not greater than 4.0 to 1.0, subject to the modifications in Amendment No. 5 set forth below; and
- Maintenance of an interest coverage ratio on a rolling four quarters basis, as adjusted, of EBITDA to interest expense, as of the end of each quarter, to be less than 2.5 to 1.0, subject to the modifications in Amendment No. 5 set forth below.

All outstanding amounts owed become due and payable upon the occurrence of certain usual and customary events of default, including, among others:

- Failure to make payments;
- Non-performance of covenants and obligations continuing beyond any applicable grace period; and
- The occurrence of a change in control of the Company, as defined under the Revolving Credit Facility.

On March 9, 2015, the Company, together with the parties thereto, entered into a Master Assignment, Agreement and Amendment No. 5 (“Amendment No. 5”) to Second Amended and Restated Credit Agreement. Amendment No. 5 amended the Revolving Credit Facility to, among other things, (i) increase the borrowing base from $145.0 million to $200.0 million, (ii) adjust the total leverage ratio for each fiscal quarter ending on or after March 31, 2015 but prior to September 30, 2016, to 5.25 to 1.00; for the fiscal quarter ending on September 30, 2016, to 5.00 to 1.00; for the fiscal quarter ending on December 31, 2016, to 4.75 to 1.00; for the fiscal quarter ending on March 31, 2017, to 4.25 to 1.00; and for each fiscal quarter ending on or after June 30, 2017, to 4.00 to 1.00, (iii) adjust the interest coverage ratio for each fiscal quarter ending on or after March 31, 2015 but prior to March 31, 2016, to 2.00 to 1.00 and for each fiscal quarter ending on or after March 31, 2016, to 2.50 to 1.00, and (iv) add the senior secured leverage ratio covenant, such ratio not to exceed, (a) for each fiscal quarter ending on or after March 31, 2015 but prior to June 30, 2016, 2.25 to 1.00 and (b) for each fiscal quarter ending on or after June 30, 2016, 2.00 to 1.00 provided that this senior secured leverage ratio shall cease to apply commencing with the first fiscal quarter end occurring after June 30, 2016 for which the total leverage ratio is equal to or less than 4.00 to 1.00.

Borrowing base redeterminations are scheduled semi-annually in May and November of each calendar year. The Company and its lender group may each request one additional unscheduled redetermination during any six-month period between scheduled redeterminations. At June 30, 2015, the Revolving Credit Facility had a borrowing base of $200.0 million, with $95.0 million borrowings outstanding and availability of $105.0 million. The next regularly scheduled redetermination is set for November 2015. Future increases in the borrowing base in excess of the original $50.0 million are limited to 17.5% of the increase in adjusted consolidated net tangible assets as defined in the indenture pursuant to which the Company's senior secured notes are issued (as discussed below in “Senior Secured Notes”).

At June 30, 2015, the Company was in compliance with all financial covenants under the Revolving Credit Facility.

Senior Secured Notes

The Company has $325.0 million aggregate principal amount of 8 5/8% Senior Secured Notes due May 15, 2018 (the "Notes") outstanding under an indenture (the "Indenture") by and among the Company, the Guarantors named therein (the "Guarantors"), Wells Fargo Bank, National Association, as Trustee (in such capacity, the "Trustee") and Collateral Agent (in such capacity, the "Collateral Agent"). The Notes bear interest at a rate of 8.625% per year, payable semi-annually in arrears on May 15 and November 15 of each year. The Notes mature on May 15, 2018.

Table of Contents

In the event of a change of control, as defined in the Indenture, each holder of the Notes will have the right to require the Company to repurchase all or any part of their notes at an offer price in cash equal to 101% of the aggregate principal amount thereof, plus accrued and unpaid interest, if any, to the date of purchase.

The Notes will be guaranteed, jointly and severally, on a senior secured basis by certain future domestic subsidiaries (the "Guarantees"). The Notes and Guarantees will rank senior in right of payment to all of the Company's and the Guarantors' future subordinated indebtedness and equal in right of payment to all of the Company's and the Guarantors' existing and future senior indebtedness. The Notes and Guarantees also will be effectively senior to the Company's unsecured indebtedness and effectively subordinated to the Company's and Guarantors' under the Revolving Credit Facility, any other indebtedness secured by a first-priority lien on the same collateral and any other indebtedness secured by assets other than the collateral, in each case to the extent of the value of the assets securing such obligation.

The Indenture contains covenants that, among other things, limit the Company's ability and the ability of its subsidiaries to:

- Transfer or sell assets or use asset sale proceeds;
- Pay dividends or make distributions, redeem subordinated debt or make other restricted payments;
- Make certain investments; incur or guarantee additional debt or issue preferred equity securities;
- Create or incur certain liens on the Company's assets;
- Incur dividend or other payment restrictions affecting future restricted subsidiaries;
- Merge, consolidate or transfer all or substantially all of the Company's assets;
- Enter into certain transactions with affiliates; and
- Enter into certain sale and leaseback transactions.

These and other covenants that are contained in the Indenture are subject to important limitations and qualifications that are described in the Indenture.

At June 30, 2015, the Notes reflected a balance of $316.5 million, net of unamortized discounts of $8.5 million, on the condensed consolidated balance sheets.

5. Fair Value Measurements

The Company's financial assets and liabilities are measured at fair value on a recurring basis. The Company discloses its recognized non-financial assets and liabilities, such as asset retirement obligations, unproved properties and other property and equipment, at fair value on a non-recurring basis. For non-financial assets and liabilities, the Company is required to disclose information that enables users of its financial statements to assess the inputs used to develop these measurements. The Company assesses its unproved properties for impairment whenever events or circumstances indicate the carrying value of those properties may not be recoverable. The fair value of the unproved properties is measured using an income approach based upon internal estimates of future production levels, current and future prices, drilling and operating costs, discount rates, current drilling plans and favorable and unfavorable drilling activity on the properties being evaluated and/or adjacent properties or estimated market data based on area transactions, which are Level 3 inputs. For the three and six months ended June 30, 2015, management's evaluation of unproved properties resulted in an impairment. Due to continued lower natural gas prices for dry gas and no current plans to drill or extend leases in Marcellus East, the Company reclassified $26,000 and $60,000, respectively, of unproved properties to proved properties for the three and six months ended June 30, 2015 related to acreage in Marcellus East. For the three and six months ended June 30, 2014, management's evaluation of unproved properties resulted in an impairment of $234,000 and $428,000, respectively, related to Marcellus East. As no other fair value measurements are required to be recognized on a non-recurring basis at June 30, 2015, no additional disclosures are provided at June 30, 2015.

As defined in the guidance, fair value is the amount 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 (an exit price). To estimate fair value, the Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (“Level 1”) and the lowest priority to unobservable inputs (“Level 3”). The three levels of the fair value hierarchy are as follows:

Table of Contents

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities. The Company’s cash equivalents consist of short-term, highly liquid investments, which have maturities of 90 days or less, including sweep investments and money market funds.
- Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.
- Level 3 inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources. These inputs may be used with internally developed methodologies or third party broker quotes that result in management’s best estimate of fair value. The Company’s valuation models consider various inputs including (a) quoted forward prices for commodities, (b) time value, (c) volatility factors and (d) current market and contractual prices for the underlying instruments. Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Level 3 instruments are commodity costless collars, index swaps, basis and fixed price swaps and put and call options to hedge natural gas, oil and NGLs price risk. At each balance sheet date, the Company performs an analysis of all applicable instruments and includes in Level 3 all of those whose fair value is based on significant unobservable inputs. The fair values derived from counterparties and third-party brokers are verified by the Company using publicly available values for relevant NYMEX futures contracts and exchange traded contracts for each derivative settlement location. Although such counterparty and third-party broker quotes are used to assess the fair value of its commodity derivative instruments, the Company does not have access to the specific assumptions used in its counterparties valuation models. Consequently, additional disclosures regarding significant Level 3 unobservable inputs were not provided and the Company does not currently have sufficient corroborating market evidence to support classifying these contracts as Level 2 instruments.

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values below incorporates various factors, including the impact of the counterparty’s non-performance risk with respect to the Company’s financial assets and the Company’s non-performance risk with respect to the Company’s financial liabilities. The Company has not elected to offset the fair value amounts recognized for multiple derivative instruments executed with the same counterparty, but reports them gross on its consolidated balance sheets.

Transfers between levels are recognized at the end of the reporting period. There were no transfers between levels during the 2015 and 2014 periods.

Table of Contents

The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2015 and December 31, 2014:

	Fair value as of June 30, 2015			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets:				
Cash and cash equivalents	$9,378	$—	$—	$9,378
Commodity derivative contracts	—	—	23,155	23,155
Liabilities:				
Commodity derivative contracts	—	—	(782)	(782)
Total	$9,378	$—	$22,373	$31,751

	Fair value as of December 31, 2014			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets:				
Cash and cash equivalents	$11,008	$—	$—	$11,008
Commodity derivative contracts	—	—	27,502	27,502
Liabilities:				
Commodity derivative contracts	—	—	—	—
Total	$11,008	$—	$27,502	$38,510

The table below presents a reconciliation of the assets and liabilities classified as Level 3 in the fair value hierarchy for the three and six months ended June 30, 2015 and 2014. Level 3 instruments presented in the table consist of net derivatives that, in management's opinion, reflect the assumptions a marketplace participant would have used at June 30, 2015 and 2014.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Balance at beginning of period	$31,823	$620	$27,502	$3,764
Total (losses) gains included in earnings	(1,790)	(8,910)	8,433	(15,424)
Purchases	45	268	911	339
Issuances	(1,127)	—	(1,313)	—
Settlements[(1)]	(6,578)	3,394	(13,160)	6,693
Balance at end of period	$22,373	$(4,628)	$22,373	$(4,628)
The amount of total losses for the period included in earnings attributable to the change in mark to market of commodity derivatives contracts still held at June 30, 2015 and 2014	$(7,777)	$(5,418)	$(3,525)	$(8,573)

(1) Included in gain (loss) on commodity derivatives contracts on the condensed consolidated statements of operations.

At June 30, 2015, the estimated fair value of accounts receivable, prepaid expenses, accounts and revenue payables and accrued liabilities approximates their carrying value due to their short-term nature. The estimated fair value of the Company's long-term debt at June 30, 2015 was $399.8 million based on quoted market prices of the Notes (Level 1) and the respective carrying value of the Revolving Credit Facility because the interest rate approximates the current market rate (Level 2).

The Company has consistently applied the valuation techniques discussed above in all periods presented.
The fair value guidance, as amended, establishes that every derivative instrument is to be recorded on the balance sheet as either an asset or liability measured at fair value. See Note 6, "Derivative Instruments and Hedging Activity."

Table of Contents

6. Derivative Instruments and Hedging Activity

The Company maintains a commodity price risk management strategy that uses derivative instruments to minimize significant, unanticipated earnings fluctuations that may arise from volatility in commodity prices. The Company uses costless collars, index, basis and fixed price swaps and put and call options to hedge oil, condensate, natural gas and NGLs price risk.

All derivative contracts are carried at their fair value on the balance sheet and all changes in value are recorded in the condensed consolidated statements of operations in (loss) gain on commodity derivatives contracts. For the three months ended June 30, 2015 and 2014, the Company reported losses of $7.8 million and $5.4 million, respectively, in the condensed consolidated statements of operations related to the change in the fair value of its commodity derivative contracts still held at June 30, 2015 and 2014. For the six months ended June 30, 2015 and 2014, the Company reported losses of $3.5 million and $8.6 million, respectively, in the condensed consolidated statements of operations related to the change in the fair value of its commodity derivative contracts still held at June 30, 2015 and 2014.

As of June 30, 2015, the following crude derivative transactions were outstanding with the associated notional volumes and weighted average underlying hedge prices:

Settlement Period	Derivative Instrument	Average Daily Volume(1) (in Bbls)	Total of Notional Volume	Floor (Long)	Short Put	Ceiling (Short)
2015	Costless three-way collar	400	73,600	$85.00	$70.00	$96.50
2015	Costless three-way collar	325	59,800	$85.00	$65.00	$97.80
2015	Costless three-way collar	50	9,200	$85.00	$65.00	$96.25
2015	Costless collar	750	130,000	$52.50	$—	$62.05
2015	Costless collar	300	55,200	$52.50	$—	$68.10
2015	Fixed price swap	600	110,400	$72.54	$—	$—
2015	Fixed price swap	250	46,000	$74.20	$—	$—
2016	Costless three-way collar	275	100,600	$85.00	$65.00	$95.10
2016	Costless three-way collar	330	120,780	$80.00	$65.00	$97.35
2016	Costless three-way collar	450	164,700	$57.50	$42.50	$80.00
2016	Put spread	550	201,300	$85.00	$65.00	$—
2016	Put spread	300	109,800	$85.50	$65.50	$—
2017	Costless three-way collar	280	102,200	$80.00	$65.00	$97.25
2017	Costless three-way collar	242	88,150	$80.00	$60.00	$98.70
2017	Costless three-way collar	200	73,000	$60.00	$42.50	$85.00
2017	Put spread	500	182,500	$82.00	$62.00	$—
2017	Costless three-way collar	200	73,000	$57.50	$42.50	$76.13
2018(2)	Put spread	425	103,275	$80.00	$60.00	$—

(1) Crude volumes hedged include oil, condensate and certain components of our NGLs production.

(2) For the period January to August 2018.

As of June 30, 2015, the following natural gas derivative transactions were outstanding with the associated notional volumes and weighted average underlying hedge prices:

Table of Contents

Settlement Period	Derivative Instrument	Average Daily Volume (in MMBtus)	Total of Notional Volume	Base Fixed Price	Floor (Long)	Short Put	Call (Long)	Ceiling (Short)
2015	Fixed price swap	400	73,600	$4.00	$—	$—	$—	$—
2015	Fixed price swap	2,500	460,000	$4.06	$—	$—	$—	$—
2015	Protective spread	2,600	478,400	$4.00	$—	$3.25	$—	$—
2015	Fixed price swap	5,000	920,000	$3.49	$—	$—	$—	$—
2015	Fixed price swap	2,000	368,000	$3.53	$—	$3.25	$—	$—
2015	Producer three-way collar	2,500	460,000	$—	$3.70	$3.00	$—	$4.09
2015	Producer three-way collar	5,000	920,000	$—	$3.77	$3.00	$—	$4.11
2015(1)	Producer three-way collar	2,000	246,000	$—	$3.00	$2.25	$—	$3.34
2015(1)	Fixed price swap	10,000	1,230,000	$2.94	$—	$—	$—	$—
2015(2)	Producer three-way collar	2,500	152,500	$—	$3.00	$2.25	$—	$3.65
2015	Basis swap(3)	2,500	460,000	$(1.12)	$—	$—	$—	$—
2015	Basis swap(3)	2,500	460,000	$(1.11)	$—	$—	$—	$—
2015	Basis swap(3)	2,500	460,000	$(1.14)	$—	$—	$—	$—
2016(4)	Producer three-way collar	2,500	762,500	$—	$3.00	$2.25	$—	$3.65
2016	Protective spread	2,000	732,000	$4.11	$—	$3.25	$—	$—
2016	Producer three-way collar	2,000	732,000	$—	$4.00	$3.25	$—	$4.58
2016	Producer three-way collar	5,000	1,830,000	$—	$3.40	$2.65	$—	$4.10
2016	Basis swap(5)	2,500	915,000	$(1.10)	$—	$—	$—	$—
2017	Short call	10,000	3,650,000	$—	$—	$—	$—	$4.75

(1) For the period July to October 2015.
(2) For the period November to December 2015.
(3) Represents basis swaps at the sales point of Dominion South.
(4) For the period January to October 2016.
(5) Represents basis swaps at the sales point of TetcoM2.

As of June 30, 2015, the following NGLs derivative transactions were outstanding with the associated notional volumes and weighted average underlying hedge prices:

Settlement Period	Derivative Instrument	Average Daily Volume (in Bbls)	Total of Notional Volume	Base Fixed Price
2015	Fixed price swap	250	46,000	$45.61
2015	Fixed price swap	500	92,000	$20.79
2016	Fixed price swap	500	183,000	$20.79

As of June 30, 2015, all of the Company's economic derivative hedge positions were with a multinational energy company or large financial institutions, which are not known to the Company to be in default on their derivative positions. The Company is exposed to credit risk to the extent of non-performance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate non-performance by such counterparties. None of the Company's derivative instruments contain credit-risk related contingent features.

In conjunction with certain derivative hedging activity, the Company deferred the payment of certain put premiums for the production month period July 2015 through August 2018. The put premium liabilities become payable monthly as the hedge production month becomes the prompt production month. The Company amortizes the deferred put premium liabilities as they become payable. The following table provides information regarding the deferred put premium liabilities for the periods indicated:

17

Table of Contents

	June 30, 2015	December 31, 2014
	(in thousands)	
Current commodity derivative put premium payable	$1,515	$2,481
Long-term commodity derivative put premium payable	4,051	4,702
Total unamortized put premium liabilities	$5,566	$7,183

	For the Three Months Ended June 30, 2015	For the Six Months Ended June 30, 2015
	(in thousands)	
Put premium liabilities, beginning balance	$7,281	$7,183
Amortization of put premium liabilities	(1,715)	(2,297)
Additional put premium liabilities	—	680
Put premium liabilities, ending balance	$5,566	$5,566

The following table provides information regarding the amortization of the deferred put premium liabilities by year as of June 30, 2015:

	Amortization
	(in thousands)
January to December 2016	$3,050
January to December 2017	1,684
January to August 2018	832
Total unamortized put premium liabilities	$5,566

Additional Disclosures about Derivative Instruments and Hedging Activities

The tables below provide information on the location and amounts of derivative fair values in the condensed consolidated statement of financial position and derivative gains and losses in the condensed consolidated statement of operations for derivative instruments that are not designated as hedging instruments:

	Fair Values of Derivative Instruments Derivative Assets (Liabilities)		
	Balance Sheet Location	Fair Value June 30, 2015	December 31, 2014
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Current assets	$13,159	$19,687
Commodity derivative contracts	Other assets	9,996	7,815
Commodity derivative contracts	Current liabilities	(166)	—
Commodity derivative contracts	Long-term liabilities	(616)	—
Total derivatives not designated as hedging instruments		$22,373	$27,502

Table of Contents

	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives For the Three Months Ended June 30,	
		2015	2014
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Loss on commodity derivatives contracts	$(1,790)	$(8,910)
Total		$(1,790)	$(8,910)

	Location of (Gain) Loss Recognized in Income on Derivatives	Amount of Loss Recognized in Income on Derivatives For the Six Months Ended June 30,	
		2015	2014
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Gain (loss) on commodity derivatives contracts	$8,433	$(15,424)
Total		$8,433	$(15,424)

7. Capital Stock

Common Stock

On May 7, 2015, the Company entered into an at-the-market issuance sales agreement with MLV & Co. LLC (the "Sales Agent") to sell, from time to time through the Sales Agent, shares of the Company's common stock (the "ATM Program"). The shares will be issued pursuant to the Company's existing effective shelf registration statement on Form S-3, as amended (Registration No. 333-193832). The Company registered shares having an aggregate offering price of up to $50.0 million. During the three months ended June 30, 2015, no shares were sold through the ATM program.

Preferred Stock

The Company currently has 40,000,000 shares of preferred stock authorized for issuance under its certificate of incorporation. The Company has designated 10,000,000 shares to constitute its 8.625% Series A Preferred Stock (the "Series A Preferred Stock") and 10,000,000 shares to constitute its 10.75% Series B Preferred Stock (the "Series B Preferred Stock"). The Series A Preferred Stock and the Series B Preferred Stock each have a par value of $0.01 per share and a liquidation preference of $25.00 per share.

Series A Preferred Stock

At June 30, 2015, there were 4,045,000 shares of the Series A Preferred Stock issued and outstanding with a $25.00 per share liquidation preference.

The Series A Preferred Stock ranks senior to the Company's common stock and on parity with the Series B Preferred Stock with respect to the payment of dividends and distribution of assets upon liquidation, dissolution or winding up.

The Series A Preferred Stock is subordinated to all of the Company's existing and future debt and all future capital stock designated as senior to the Series A Preferred Stock.
The Series A Preferred Stock cannot be converted into common stock, but may be redeemed, at the Company's option for $25.00 per share plus any accrued and unpaid dividends.
There is no mandatory redemption of the Series A Preferred Stock.
The Company pays cumulative dividends on the Series A Preferred Stock at a fixed rate of 8.625% per annum of the $25.00 per share liquidation preference. For the three and six months ended June 30, 2015, the Company recognized dividend expense of $2.2 million and $4.4 million, respectively, for the Series A Preferred Stock.

Table of Contents

Series B Preferred Stock

At June 30, 2015, there were 2,140,000 shares of the Series B Preferred Stock issued and outstanding with a $25.00 per share liquidation preference.

The Series B Preferred Stock ranks senior to the Company’s common stock and on parity with the Series A Preferred Stock with respect to the payment of dividends and distribution of assets upon liquidation, dissolution or winding up. The Series B Preferred Stock are subordinated to all of the Company’s existing and future debt and all future capital stock designated as senior to the Series B Preferred Stock.

Except upon a change in ownership or control, as defined in the Series B Preferred Stock certificate of designations of rights and preferences, the Series B Preferred Stock may not be redeemed before November 15, 2018, at or after which time it may be redeemed at the Company’s option for $25.00 per share in cash. Following a change in ownership or control, the Company will have the option to redeem the Series B Preferred Stock within 90 days of the occurrence of the change in control, in whole but not in part for $25.00 per share in cash, plus accrued and unpaid dividends (whether or not declared), up to, but not including the redemption date. If the Company does not exercise its option to redeem the Series B Preferred Stock upon a change of ownership or control, the holders of the Series B Preferred Stock have the option to convert the shares of Series B Preferred Stock into the Company's common stock based upon on an average common stock trading price then in effect but limited to an aggregate of 11.5207 shares of the Company’s common stock per share of Series B Preferred Stock, subject to certain adjustments. If the Company exercises any of its redemption rights relating to shares of Series B Preferred Stock, the holders of Series B Preferred Stock will not have the conversion right described above with respect to the shares of Series B Preferred Stock called for redemption.

There is no mandatory redemption of the Series B Preferred Stock.

The Company pays cumulative dividends on the Series B Preferred Stock at a fixed rate of 10.75% per annum of the $25.00 per share liquidation preference. For the three and six months ended June 30, 2015, the Company recognized dividend expense of $1.4 million and $2.9 million, respectively, for the Series B Preferred Stock.

Other Share Issuances

The following table provides information regarding the issuances and forfeitures of common stock pursuant to the Company's long-term incentive plan for the periods indicated:

	For the Three Months Ended June 30, 2015	For the Six Months Ended June 30, 2015
Other share issuances:		
Shares of restricted common stock granted	—	1,421,224
Shares of restricted common stock vested	—	1,274,872
Shares of common stock issued pursuant to PBUs vested, net of forfeitures	—	497,636
Shares of restricted common stock surrendered upon vesting/exercise[1]	—	382,238
Shares of restricted common stock forfeited	841	24,498

(1) Represents shares of common stock forfeited in connection with the payment of estimated withholding taxes on shares of restricted common stock that vested during the period.

On June 12, 2014, the Company's stockholders approved an amendment and restatement to the Gastar Exploration Inc. Long-Term Incentive Plan (the “LTIP”), effective April 24, 2014, to, among other things, increase the number of shares of common stock reserved for issuance under the LTIP by 3,000,000 shares of common stock. There were 2,850,275 shares of common stock available for issuance under the LTIP at June 30, 2015.

Shares Reserved

At June 30, 2015, the Company had 866,600 common shares reserved for the exercise of stock options.

Table of Contents

8. Interest Expense

The following table summarizes the components of interest expense for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Interest expense:				
Cash and accrued	$7,241	$7,208	$15,169	$14,342
Amortization of deferred financing costs(1)	915	758	1,736	1,491
Capitalized interest	(1,220)	(1,054)	(2,408)	(2,030)
Total interest expense	$6,936	$6,912	$14,497	$13,803

(1) The three months ended June 30, 2015 and 2014 includes $629,000 and $570,000, respectively, of debt discount accretion related to the Notes. The six months ended June 30, 2015 and 2014 includes $1.2 million and $1.1 million, respectively, of debt discount accretion related to the Notes.

9. Income Taxes

For the three and six months ended June 30, 2015 and 2014, respectively, the Company did not recognize a current income tax benefit or provision as the Company has a full valuation allowance against assets created by net operating losses generated. The Company believes it more likely than not that the assets will not be utilized.

10. Earnings per Share

In accordance with the provisions of current authoritative guidance, basic earnings or loss per share is computed on the basis of the weighted average number of common shares outstanding during the periods. Diluted earnings or loss per share is computed based upon the weighted average number of common shares outstanding plus the assumed issuance of common shares for all potentially dilutive securities.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands, except per share and share data)			
Net (loss) income attributable to common stockholders	$(118,014)	$2,016	$(121,018)	$51
Weighted average common shares outstanding - basic	77,611,167	58,702,982	77,364,368	58,462,124
Incremental shares from unvested restricted shares	—	2,514,542	—	2,563,673
Incremental shares from outstanding stock options	—	112,232	—	106,499
Incremental shares from outstanding PBUs	—	593,118	—	541,971
Weighted average common shares outstanding - diluted	77,611,167	61,922,874	77,364,368	61,674,267
Net (loss) income per share of common stock attributable to common stockholders:				
Basic	$(1.52)	$0.03	$(1.56)	$—
Diluted	$(1.52)	$0.03	$(1.56)	$—
Common shares excluded from denominator as anti-dilutive:				
Unvested restricted shares	8,970	—	93,733	—
Stock options	—	—	—	—
Unvested PBUs	44,213	—	94,488	—
Total	53,183	—	188,221	—

Table of Contents

11. Commitments and Contingencies

Litigation

Gastar Exploration Ltd vs. U.S. Specialty Ins. Co. and Axis Ins. Co. (Cause No.2010-11236) District Court of Harris County, Texas 190th Judicial District. On February 19, 2010, the Company filed a lawsuit claiming that the Company was due reimbursement of qualifying claims related to the settlement and associated legal defense costs under the Company's directors and officers liability insurance policies related to the ClassicStar Mare Lease Litigation settled on December 17, 2010 for $21.2 million. The combined coverage limits under the directors and officers liability coverage is $20.0 million. The District Court granted the underwriters' summary judgment request by a ruling dated January 4, 2012. The Company appealed the District Court ruling and on July 15, 2013, the Fourteenth Court of Appeals of Texas reversed the summary judgment ruling granted against the Company on the basis of the policies' prior-and-pending litigation endorsement and remanded the case for further proceedings in the District Court. The insurers filed a motion for reconsideration in the Fourteenth Court of Appeals, which that court denied. The insurers then sought discretionary review from the Texas Supreme Court, which that court denied on February 27, 2015. The insurers then filed in the Texas Supreme Court a motion for rehearing of their denied petition for review, which the court has denied. The case has now been remanded to the District Court. The District Court proceedings will include, but not be limited to, a determination of the portion of the Company's settlement of the ClassicStar Mare Lease Litigation that is covered by the insuring agreements. On July 28, 2015, the parties submitted briefs in support of their respective positions regarding the issues left to be resolved in the case and the requisite amount of time for such proceedings. The parties are currently scheduled for a hearing with the court on August 10, 2015, at which time it is anticipated the court will enter a docket control order establishing a time frame for the remainder of the issues to be litigated.

Husky Ventures, Inc. vs. J. Russell Porter, Michael A. Gerlich, Michael McCown, Keith R. Blair, Henry J. Hansen and John M. Selser Sr. (Case No. CIV-15-637-R) United States District Court for the Western District of Oklahoma. On June 9, 2015, Husky Ventures, Inc. filed this action against five of the Company’s senior officers and our non-executive chairman of the board alleging that each of the defendants committed fraud by grossly understating the costs of certain oil and gas interests the Company acquired that were outside a Mid-Continent AMI between Husky and the Company while inflating the costs of interests simultaneously acquired within the AMI. Husky alleges this resulted in the defendants improperly shifting a disproportionate amount of acquisition costs away from the Company and to Husky. Husky seeks to recover actual damages alleged to be in excess of $2.0 million, as well as punitive damages and attorneys’ fees. This case is currently stayed until the earlier of a settlement or a ruling on the Company’s request for a preliminary injunction in another action involving Husky filed in the same court in which the Company intervened and is seeking to replace Husky as operator of several wells within the AMI. The Company is advancing defense costs to the defendants in this case and, depending upon the outcome, the Company may be obligated to indemnify each of the defendants in this action for any loss or damages incurred by the defendants.

The Company has been expensing legal costs on these proceedings as they are incurred.

The Company is party to various legal proceedings arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and the liability the Company may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued for with respect to such matters. Net of available insurance and performance of contractual defense and indemnity obligations, where applicable, management does not believe any such matters will have a material adverse effect on the Company’s financial position, results of operations or cash flows.

Table of Contents

12. Statement of Cash Flows – Supplemental Information

The following is a summary of the supplemental cash paid and non-cash transactions for the periods indicated:

	For the Six Months Ended June 30,	
	2015	2014
	(in thousands)	
Cash paid for interest, net of capitalized amounts	$12,735	$14,469
Non-cash transactions:		
Capital expenditures excluded from accounts payable and accrued drilling costs	$(7,477)	$655
Capital expenditures included in accounts receivable	$—	$4,077
Capital expenditures excluded from prepaid expenses	$—	$51
Asset retirement obligation included in oil and natural gas properties	$227	$45
Application of advances to operators	$9,904	$19,926
Other	$—	$(3)

23

Table of Contents

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report contains “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements other than statements of historical fact included or incorporated by reference in this report are forward-looking statements, including, without limitation, all statements regarding future plans, business objectives, strategies, expected future financial position or performance, future covenant compliance, expected future operational position or performance, budgets and projected costs, future competitive position or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as “may,” “will,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “a “believe,” “estimate,” “predict,” “potential,” “pursue,” “target” or “continue,” the negative of such terms or variations thereon, other comparable terminology.

The forward-looking statements contained in this report are largely based on our expectations and beliefs concerning future developments and their potential effect on us, which reflect certain estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions, operating trends, and other factors. Forward-looking statements may include statements that relate to, among other things, our:

- financial position;
- business strategy and budgets;
- capital expenditures;
- drilling of wells, including the anticipated scheduling and results of such operations;
- oil, natural gas and NGLs reserves;
- timing and amount of future production of oil, condensate, natural gas and NGLs;
- operating costs and other expenses;
- cash flow and liquidity;
- compliance with covenants under our indenture and credit agreements;
- availability of capital;
- prospect development; and
- property acquisitions and sales.

Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. As such, management’s assumptions about future events may prove to be inaccurate. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf. Management cautions all readers that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events and circumstances they describe will occur. Factors that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements herein include, but are not limited to:

- the supply and demand for oil, condensate, natural gas and NGLs;
- continued low or further declining prices for oil, condensate, natural gas and NGLs;
- worldwide political and economic conditions and conditions in the energy market;
- the extent to which we are able to realize the anticipated benefits from acquired assets;
- our ability to raise capital to fund capital expenditures or repay or refinance debt upon maturity;
- our ability to meet financial covenants under our indenture or credit agreements or the ability to obtain amendments or waivers to effect such compliance;
- the ability and willingness of our current or potential counterparties, third-party operators or vendors to enter into transactions with us and/or to fulfill their obligations to us;
- failure of our joint interest partners to fund any or all of their portion of any capital program;
- the ability to find, acquire, market, develop and produce new oil and natural gas properties;
- uncertainties about the estimated quantities of oil and natural gas reserves and in the projection of future rates of production and timing of development expenditures of proved reserves;
- strength and financial resources of competitors;

Table of Contents

- availability and cost of material and equipment, such as drilling rigs and transportation pipelines;
- availability and cost of processing and transportation;
- changes or advances in technology;
- the risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry wells, operating hazards inherent to the oil and natural gas business and down hole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells or pipeline mishaps;
- environmental risks;
- possible new legislative initiatives and regulatory changes potentially adversely impacting our business and industry, including, but not limited to, national healthcare, hydraulic fracturing, state and federal corporate income taxes, retroactive royalty or production tax regimes, changes in environmental regulations, environmental risks and liability under federal, state and local environmental laws and regulations;
- effects of the application of applicable laws and regulations, including changes in such regulations or the interpretation thereof;
- potential losses from pending or possible future claims, litigation or enforcement actions;
- potential defects in title to our properties or lease termination due to lack of activity or other disputes with mineral lease and royalty owners, whether regarding calculation and payment of royalties or otherwise;
- the weather, including the occurrence of any adverse weather conditions and/or natural disasters affecting our business;
- our ability to find and retain skilled personnel; and
- any other factors that impact or could impact the exploration of natural gas or oil resources, including, but not limited to, the geology of a resource, the total amount and costs to develop recoverable reserves, legal title, regulatory, natural gas administration, marketing and operational factors relating to the extraction of oil and natural gas.

For a more detailed description of the risks and uncertainties that we face and other factors that could affect our financial performance or cause our actual results to differ materially from our projected results please see (i) Part II, Item 1A. “Risk Factors” and elsewhere in this report, (ii) Part I, Item 1A. “Risk Factors” and elsewhere in our 2014 Form 10-K, (iii) our subsequent reports and registration statements filed from time to time with the SEC and (iv) other announcements we make from time to time.
You should not unduly rely on these forward-looking statements in this report, as they speak only as of the date of this report. Except as required by law, we undertake no obligation to publicly update, revise or release any revisions to these forward-looking statements after the date on which they are made to reflect new information, events or circumstances occurring after the date of this report or to reflect the occurrence of unanticipated events.

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

Overview

We are an independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and NGLs in the U.S. Our principal business activities include the identification, acquisition, and subsequent exploration and development of oil and natural gas properties with an emphasis on unconventional reserves, such as shale resource plays. In Oklahoma, we are developing the primarily oil-bearing reservoirs of the Hunton Limestone horizontal oil play and expect to test other prospective formations on the same acreage, including the Meramec Shale (middle Mississippi Lime) and the Woodford Shale , which we refer to as the STACK Play. In West Virginia, we are developing liquids-rich natural gas in the Marcellus Shale and have drilled and completed our first two successful dry gas Utica Shale/Point Pleasant wells on our acreage.
Our current operational activities are conducted in, and our consolidated revenues are generated from, markets exclusively in the U.S. As of June 30, 2015, our major assets consist of approximately 234,600 gross (123,100 net) acres in Oklahoma and approximately 66,700 gross (46,700 net) acres in the Marcellus Shale in West Virginia and southwestern Pennsylvania, of which approximately 25,000 gross (10,600 net) acres have Utica Shale/Point Pleasant potential, of which approximately 4,300 gross (1,900 net) acres are pending lease finalization. Subsequent to June 30,

2015 and as a result of the July 6, 2015 sale of

25

Table of Contents

approximately 29,500 gross (19,200 net) acres in Kingfisher County, Oklahoma, our Mid-Continent assets consist of approximately 205,100 gross (103,900 net) acres in Oklahoma.

The following discussion addresses material changes in our results of operations for the three and six months ended June 30, 2015 compared to the three and six months ended June 30, 2014 and material changes in our financial condition since December 31, 2014. This discussion should be read in conjunction with our condensed consolidated financial statements and the notes thereto included in Part I, Item 1. "Financial Statements" of this report, as well as our 2014 Form 10-K, which includes important disclosures regarding our critical accounting policies as part of Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Oil and Natural Gas Activities

The following provides an overview of our major oil and natural gas projects. While actively pursuing specific exploration and development activities in each of the following areas, there is no assurance that new drilling opportunities will be identified or that any new drilling opportunities will be successful if drilled. We are also concentrating our drilling activities in the Mid-Continent during 2015 in light of the substantial downturn in oil, natural gas and NGLs prices that has occurred since November 2014. The dramatic pricing downturns that we are experiencing may cause us to make further changes in our drilling plans.

Mid-Continent Horizontal Oil Play.

The Hunton Limestone is a limestone formation stretching over approximately 2.7 million acres mainly in Oklahoma, but also in the neighboring states of Texas, New Mexico and Arkansas. Hunton Limestone development has been attractive due to the high quality oil production and the associated production of high BTU content natural gas in the area. At June 30, 2015, we held leases covering approximately 234,600 gross (123,100 net) acres in Major, Garfield, Canadian, Kingfisher, Logan, Blaine and Oklahoma Counties, Oklahoma within the Hunton Limestone horizontal oil play.

On July 6, 2015, we sold to an undisclosed private third party certain non-core assets comprised of 38 gross (16.7 net) wells producing approximately net 170 Boe/d (41% oil) for the three months ended March 31, 2015 and approximately 29,500 gross (19,200 net) acres in Kingfisher County, Oklahoma for approximately $46.1 million, of which $6.6 million was deposited during the second quarter of 2015 and accounted for in other liabilities at June 30, 2015. The sale will be reflected as a reduction to the full cost pool and we will not record a gain or loss related to the divestiture as it is not significant to the full cost pool.

In our initial AMI with our Mid-Continent partner, we currently pay 50% of lease acquisition costs for a 50% working interest. We pay 54.25% of the lease acquisition costs in the two additional prospect areas for a 50% working interest. In the initial prospect area, we are currently responsible for paying only the drilling and completion costs associated with our 50% working interest (our approximate net revenue interest is 39.0%). In all subsequent prospect areas, we pay 54.25% of gross drilling and completion costs to earn a 50% working interest. Our AMI partner acts as operator and handles all drilling, completion and production activities, and we handle leasing and permitting activities in certain areas of the AMI. For 2015, our focus is to drill in areas that we believe will result in the most significant proved reserve recognition to capital dollars spent and renew acreage in areas that our past drilling has proven to provide attractive returns and production rates and substantial reserve additions. We may elect to sell in the future any acreage that is determined to provide less attractive returns, productions and reserve additions or is outside of our drilling focus to reduce net capital expenditures.

Table of Contents

As of June 30, 2015 and currently as of the date of this report, we had initial production and drilling operations at various stages on the following wells in our original AMI in the Hunton Limestone formation:

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Peak Production Rates[(1)] (Boe/d)	Cumulative Production Averages[(2)] Boe/d	% Oil	Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
LB 1-1H	47.6%	4,400	791	242	65%	January 23, 2015	$4.4
Hubbard 1-23H[(3)]	57.0%	4,600	N/A	22	95%	February 19, 2015	$6.1
Boss Hogg 1-14H	50.0%	4,400	129	61	68%	February 21, 2015	$7.4
Bo 1-23H	43.8%	4,900	547	307	47%	February 28, 2015	$5.0
The River 1-22H	39.7%	4,400	1,250	943	34%	March 14, 2015	$4.6
Bigfoot 1-9H	47.4%	4,800	161	112	58%	March 17, 2015	$5.1
Falcon 1-5H	51.5%	4,700	1,202	547	84%	April 1, 2015	$4.5
Dorothy 1-12H	49.5%	5,000	N/A	17	78%	April 10, 2015	$4.5
Polar Bear 1-20H	47.7%	4,400	403	180	87%	May 5, 2015	$5.0
Unruh 1-34H[(4)]	49.0%	4,900	N/A	N/A	N/A	Awaiting completion	$7.1

(1) Represents highest daily gross Boe rate.
(2) Represents gross cumulative production divided by actual producing days through July 19, 2015.
(3) After payout working interest is 49.9%.
(4) Approximate gross costs to drill and complete includes costs to re-drill the well due to an initial horizontal casing collapse.

In addition to the wells above, we also participated on a non-operated basis in wells outside of the AMI operated by our AMI partner. As of June 30, 2015 and currently as of the date of this report, we had initial production and drilling operations at various stages on the following non-operated wells outside the original AMI in the Hunton Limestone formation:

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Peak Production Rates[(1)] (BOE/d)	Cumulative Production Averages[(2)] BOE/d	% Oil	Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
Wolf 1-9H	16.7%	3,600	391	216	58%	January 3, 2015	$5.5

(1) Represents highest daily gross Boe rate.

(2) Represents gross cumulative production divided by actual producing days through July 19, 2015.

We are currently involved as an intervener in litigation involving our AMI partner which was filed in the United States District Court for the Western District of Oklahoma. We have sought a preliminary injunction and declaratory relief to enforce our contractual position under our joint operating agreements and our appointment as operator of a number of our oil and gas wells in the AMI that are currently operated by our AMI partner. Following our intervention in this lawsuit, our AMI partner filed a lawsuit against several of our officers and a director on an unrelated matter, as described in Part I, Item 1. "Financial Statements, Note 11 - Commitments and Contingencies" of this report.

Table of Contents

As of June 30, 2015 and currently as of the date of this report, we had production and drilling operations at various stages on the following operated wells on our acquired West Edmond Hunton Lime Unit ("WEHLU") acreage in the lower Hunton Limestone formation:

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Peak Production Rates[1] (BOE/d)	Cumulative Production Averages[2]		Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
				BOE/d	% Oil		
Upper Hunton Completions							
Warsaw 33-2H	98.3%	4,900	615	260	63%	February 13, 2015	$4.0
Blair Farms 31-1H	98.3%	6,500	509	353	83%	May 7, 2015	$5.0
Easton 22-4H	98.3%	6,500	604	357	89%	May 20, 2015	$3.1
Jetson 8-2H	98.3%	5,900	N/A	N/A	N/A	Awaiting completion	$3.5
Arcadia Farms 15-2H	98.3%	6,800	N/A	N/A	N/A	Drilling	$3.4
O' Donnell 5-1H	98.3%	6,800	N/A	N/A	N/A	Drilling	$3.4
Lower Hunton Completions							
Warsaw 33-3H	98.3%	5,800	663	250	62%	February 14, 2015	$6.4
Easton 22-3H	98.3%	6,500	N/A	335	83%	May 24, 2015	$5.0
Davis 9-2H	98.3%	6,800	N/A	N/A	N/A	Awaiting flowback	$4.5
Davis 9-4H	98.3%	7,400	N/A	N/A	N/A	Awaiting flowback	$4.6
Jetson 8-1H	98.3%	5,000	N/A	N/A	N/A	Awaiting completion	$5.6
Arcadia Farms 15-1CH	98.3%	6,800	N/A	N/A	N/A	Drilling	$5.0
O'Donnell 5-2CH	98.3%	7,500	N/A	N/A	N/A	Drilling	$5.0
Warsaw 33-1(3)	98.3%	N/A	59	27	47%	March 13, 2015	$3.8

(1) Represents highest daily gross Boe rate.
(2) Represents gross cumulative production divided by actual producing days through July 19, 2015.
(3) The Warsaw 33-1 is a commingled vertical pilot well completed in the upper, middle and lower Hunton zones.

We continue to target our horizontal laterals in the Hunton Limestone formation and increase the number of fracturing stages in the horizontal lateral as warranted by log analysis. We are continuing to monitor well flow back results on recently drilled and completed wells and remain encouraged by the overall well results to date.

Table of Contents

The following table provides production and operational information about the Mid-Continent for the periods indicated:

Mid-Continent	For the Three Months Ended June 30, 2015	2014	For the Six Months Ended June 30, 2015	2014
Net Production:				
Oil and condensate (MBbl)	304	167	601	303
Natural gas (MMcf)	889	631	1,686	1,289
NGLs (MBbl)	113	103	209	150
Total net production (MBoe)	565	374	1,091	667
Net Daily Production:				
Oil and condensate (MBbl/d)	3.3	1.8	3.3	1.7
Natural gas (MMcf/d)	9.8	6.9	9.3	7.1
NGLs (MBbl/d)	1.2	1.1	1.2	0.8
Total net daily production (MBoe/d)	6.2	4.1	6.0	3.7
Average sales price per unit(1):				
Oil and condensate (per Bbl)	$53.86	$101.81	$50.40	$100.11
Natural gas (per Mcf)	$2.47	$3.85	$2.81	$4.78
NGLs (per Bbl)	$14.98	$34.01	$14.69	$37.26
Average sales price per Boe(1)	$35.86	$61.13	$34.92	$63.00
Selected operating expenses (in thousands):				
Production taxes	$489	$745	$840	$1,360
Lease operating expenses(2)	$5,666	$3,793	$10,692	$6,632
Transportation, treating and gathering	$3	$12	$7	$22
Selected operating expenses per Boe:				
Production taxes	$0.87	$1.99	$0.77	$2.04
Lease operating expenses(2)	$10.04	$10.13	$9.80	$9.94
Transportation, treating and gathering	$0.01	$0.03	$0.01	$0.03
Production costs(3)	$10.04	$10.17	$9.80	$9.97

(1) Excludes the impact of hedging activities.

(2) Lease operating expenses for the three and six months ended June 30, 2015 include $1.4 million and $2.8 million, respectively, of workover expense for one-time production enhancing workovers completed on certain WEHLU wells. Excluding workover expense, lease operating expense per Boe for the three and six months ended June 30, 2015 would have been $7.59 per Boe and $7.27 per Boe, respectively, compared to $10.00 per Boe and $9.87 per Boe for the three and six months ended June 30, 2014, respectively.

(3) Production costs include lease operating expense, insurance, gathering and workover expense and excludes ad valorem and severance taxes.

Appalachian Basin.

Marcellus Shale. The Marcellus Shale is Devonian aged shale that underlies much of the Appalachian region of Pennsylvania, New York, Ohio, West Virginia and adjacent states. The depth of the Marcellus Shale and its low permeability make the Marcellus Shale an unconventional exploration target in the Appalachian Basin. Advancements in horizontal drilling and stimulation have produced promising results in the Marcellus Shale. These developments have resulted in increased leasing and drilling activity in the area. As of June 30, 2015, our acreage position in the play was approximately 66,700 gross (46,700 net) acres. We refer to the approximately 28,800 gross (12,400 net) acres reflecting our interest in our Marcellus Shale assets in West Virginia and Pennsylvania subject to the Atinum Joint Venture described below as our Marcellus West acreage. We refer to the approximately 37,900 gross (34,400 net) acres in Preston, Tucker, Pocahontas, Randolph and Pendleton Counties, West Virginia as our Marcellus East acreage. The entirety of our acreage is believed to be in the core, over-pressured area of the Marcellus play. We continue to opportunistically swap acreage with adjacent operators in order to optimize our acreage and maximize horizontal lateral lengths.

Table of Contents

On September 21, 2010, we entered into the Atinum Joint Venture pursuant to which we ultimately assigned to Atinum, for $70.0 million in total consideration, a 50% working interest in certain undeveloped acreage and shallow producing wells. Atinum has the right to participate in any future leasehold acquisitions made by us within Ohio, New York, Pennsylvania and West Virginia, excluding the counties of Pendleton, Pocahontas, Preston, Randolph and Tucker, West Virginia, on terms identical to those governing the existing Atinum Joint Venture. We are the operator and are obligated to offer any future lease acquisitions to Atinum on a 50/50 basis. Atinum will pay us on an annual basis an amount equal to 10% of lease bonuses and third party leasing costs, up to $20.0 million, and 5% of such costs on activities above $20.0 million.

The Atinum Joint Venture pursued an initial three-year development program that called for the partners to drill a minimum of 60 operated horizontal wells by year-end 2013. Due to natural gas price declines, we and Atinum agreed to reduce the minimum wells to be drilled requirements from 60 gross wells to 51 gross wells. At June 30, 2015, 74 gross (37.0 net) operated Marcellus Shale horizontal wells were capable of production. All of our Marcellus Shale well operations to date were drilled under the Atinum Joint Venture. The Atinum Joint Venture agreement expires on November 1, 2015.

Due to the current price environment in the Appalachian Basin, we have suspended our drilling operations in the Appalachian Basin until product prices improve. As of June 30, 2015, we had no drilling operations in progress on our Marcellus Shale acreage in Marshall County, West Virginia.

The following table provides production and operational information for the Marcellus Shale for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Marcellus Shale	2015	2014	2015	2014
Net Production:				
Oil and condensate (MBbl)	65	40	135	107
Natural gas (MMcf)	2,071	2,049	4,228	4,463
NGLs (MBbl)	185	105	307	213
Total net production (MBoe)	595	487	1,147	1,064
Net Daily Production:				
Oil and condensate (MBbl/d)	0.7	0.4	0.7	0.6
Natural gas (MMcf/d)	22.8	22.5	23.4	24.7
NGLs (MBbl/d)	2.0	1.2	1.7	1.2
Total net daily production (MBoe/d)	6.5	5.4	6.3	5.9
Average sales price per unit (1)(2):				
Oil and condensate (per Bbl)	$18.82	$134.02	$19.57	$82.31
Natural gas (per Mcf)	$0.64	$7.38	$1.18	$6.01
NGLs (per Bbl)	$2.69	$13.49	$3.93	$28.00
Average sales price per Boe (1)(2)	$5.12	$45.04	$7.69	$39.10
Selected operating expenses (in thousands):				
Production taxes(3)	$275	$1,293	$717	$2,571
Lease operating expenses(3)	$1,550	$1,084	$2,539	$2,288
Transportation, treating and gathering(3)	$450	$2,134	$910	$2,749
Selected operating expenses per Boe:				
Production taxes(3)	$0.46	$2.66	$0.63	$2.42
Lease operating expenses(3)	$2.61	$2.23	$2.21	$2.15
Transportation, treating and gathering(3)	$0.76	$4.38	$0.79	$2.58
Production costs (4)	$2.73	$6.20	$2.36	$4.33

(1) Excludes the impact of hedging activities.

(2)

The three and six months ended June 30, 2014 include the benefit of a one-time revenue adjustment related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, average sales prices would have been as follows:

Table of Contents

	For the Three Months Ended June 30, 2014	For the Six Months Ended June 30, 2014
Marcellus Shale		
Average sales price per unit:		
Oil and condensate (per Bbl)	$ 55.59	$ 52.97
Natural gas (per Mcf)	$ 3.42	$ 4.19
NGLs (per Bbl)	$ 19.93	$ 31.17
Average sales price per Boe	$ 23.26	$ 29.14

(3) The three and six months ended June 30, 2014 include a one-time adjustment to production taxes, lease operating expenses and transportation, treating and gathering related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, production taxes, lease operating expenses and transportation, treating and gathering per Boe would have been as follows:

	For the Three Months Ended June 30, 2014	For the Six Months Ended June 30, 2014
Marcellus Shale		
Selected operating expenses per Boe:		
Production taxes	$ 1.46	$ 1.87
Lease operating expenses	$ 2.61	$ 2.32
Transportation, treating and gathering	$ 1.13	$ 1.09

(4) Production costs include lease operating expenses, insurance, gathering and workover expense and excludes ad valorem and severance taxes. Excluding the arbitration settlement adjustment impact, production costs for the three and six months ended June 30, 2014 would have been as follows:

	For the Three Months Ended June 30, 2014	For the Six Months Ended June 30, 2014
Marcellus Shale		
Selected operating expenses per Boe:		
Production costs	$ 3.33	$ 3.02

Utica Shale/Point Pleasant. The Utica Shale is Ordovician aged shale that underlies much of the Appalachian region of Pennsylvania, Ohio and West Virginia. The depth of the Utica Shale and its low permeability make it an unconventional exploration target in the Appalachian Basin. Advancements in horizontal drilling and hydraulic fracture stimulation have produced promising results in the Utica Shale, some in close proximity to our existing Marcellus West acreage. Based on our successful completion of two Utica Shale wells, log analysis of offsetting wells and recent Utica Shale completions by other nearby operators, we believe that our Marcellus West acreage should be prospective for high-pressure, high-deliverability dry natural gas development in the Utica Shale/Point Pleasant formation. We drilled the Simms U-5H to a total vertical depth of 11,500 feet and drilled an approximate 4,400-foot lateral and completed it with a 25-stage fracture stimulation. The Simms U-5H was producing at a last five-day average rate of 5.4 MMcf/d of natural gas and had total cumulative production of 3.0 Bcf as of July 20, 2015. Our working interest in the Simms U-5H is 50.0% (43.2% net revenue interest). We drilled the Blake U-7H to a total vertical depth of 11,100 feet and drilled an approximate 6,600-foot lateral and completed it with a 34-stage fracture stimulation. The Blake U-7H was producing at a last five-day average rate of 17.6 MMcf/d of natural gas and had total cumulative production of 1.2 Bcf as of July 20, 2015. Our working interest in the Blake U-7H is 50.0% (41.1% net revenue interest). The estimated cost to drill and complete the Blake U-7H was approximately $15.1 million. All of our Utica Shale/Point Pleasant well operations to date were drilled under the Atinum Joint Venture. The Atinum Joint Venture agreement expires on November 1, 2015.

Table of Contents

The following table provides production and operational information for Appalachia for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Utica Shale	2015	2014	2015	2014
Net Production:				
Natural gas (MMcf)	615	—	955	—
Total net production (MBoe)	102	—	159	—
Net Daily Production:				
Natural gas (MMcf/d)	6.8	—	5.3	—
Total net daily production (MBoe/d)	1.1	—	0.9	—
Average sales price per unit [1]:				
Natural gas (per Mcf)	$0.69	$—	$0.99	$—
Average sales price per Boe [1]	$4.14	$—	$5.93	$—
Selected operating expenses (in thousands):				
Production taxes	$58	$—	$104	$—
Lease operating expenses	$26	$—	$31	$—
Transportation, treating and gathering	$89	$—	$123	$—
Selected operating expenses per Boe:				
Production taxes	$0.57	$—	$0.65	$—
Lease operating expenses	$0.25	$—	$0.20	$—
Transportation, treating and gathering	$0.87	$—	$0.78	$—
Production costs [2]	$1.12	$—	$0.97	$—

(1) Excludes the impact of hedging activities.

(2) Production costs include lease operating expenses, insurance, gathering and workover expense and excludes ad valorem and severance taxes.

Results of Operations

The following is a comparative discussion of the results of operations for the periods indicated. It should be read in conjunction with the condensed consolidated financial statements and the related notes to the condensed consolidated financial statements found elsewhere in this report.

Table of Contents

The following table provides information about production volumes, average prices of oil and natural gas and operating expenses for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
	(In thousands, except per unit amounts)			
Net Production:				
Oil and condensate (MBbl)	369	207	736	410
Natural gas (MMcf)	3,575	2,680	6,870	5,752
NGLs (MBbl)	297	208	516	363
Total net production (MBoe)	1,262	861	2,397	1,732
Net Daily production:				
Oil and condensate (MBbl/d)	4.1	2.3	4.1	2.3
Natural gas (MMcf/d)	39.3	29.5	38.0	31.8
NGLs (MBbl/d)	3.3	2.3	2.9	2.0
Total net daily production (MBoe/d)	13.9	9.5	13.2	9.6
Average sales price per unit(1):				
Oil and condensate per Bbl, excluding impact of hedging activities	$47.68	$108.06	$44.76	$95.45
Oil and condensate per Bbl, including impact of hedging activities (2)	$52.20	$102.52	$49.86	$91.15
Natural gas per Mcf, excluding impact of hedging activities	$1.10	$6.55	$1.55	$5.73
Natural gas per Mcf, including impact of hedging activities (2)	$1.68	$6.06	$2.11	$5.14
NGLs per Bbl, excluding impact of hedging activities	$7.34	$23.62	$8.29	$31.82
NGLs per Bbl, including impact of hedging activities (2)	$14.97	$18.66	$16.72	$27.20
Average sales price per Boe, excluding impact of hedging activities	$18.79	$52.03	$19.97	$48.31
Average sales price per Boe, including impact of hedging activities (2)	$23.54	$47.98	$24.96	$44.35
Selected operating expenses:				
Production taxes(3)	$822	$2,037	$1,662	$3,931
Lease operating expenses(3)	$7,242	$4,877	$13,261	$8,921
Transportation, treating and gathering(3)	$542	$2,146	$1,039	$2,771
Depreciation, depletion and amortization	$16,080	$10,280	$30,551	$22,662
Impairment of natural gas and oil properties	$100,152	$—	$100,152	—
General and administrative expense	$4,421	$3,893	$8,669	$8,656
Selected operating expenses per Boe:				
Production taxes(3)	$0.65	$2.37	$0.69	$2.27
Lease operating expenses(3)(4)	$5.74	$5.66	$5.53	$5.15
Transportation, treating and gathering(3)	$0.43	$2.49	$0.43	$1.60
Depreciation, depletion and amortization	$12.74	$11.94	$12.75	$13.09
General and administrative expense	$3.50	$4.52	$3.62	$5.00
Production costs(5)	$5.87	$7.92	$5.66	$6.51

Table of Contents

(1)The three and six months ended June 30, 2014 include the benefit of a one-time revenue adjustment related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, average sales prices would have been as follows:

	For the Three Months Ended June 30, 2014	For the Six Months Ended June 30, 2014
Average sales price per unit:		
Oil and condensate per Bbl, excluding impact of hedging activities	$92.84	$87.77
Oil and condensate per Bbl, including impact of hedging activities (2)	$87.30	$83.47
Natural gas per Mcf, excluding impact of hedging activities	$3.52	$4.32
Natural gas per Mcf, including impact of hedging activities (2)	$3.03	$3.73
NGLs per Bbl, excluding impact of hedging activities	$26.88	$33.69
NGLs per Bbl, including impact of hedging activities (2)	$21.92	$29.07
Average sales price per Boe, excluding impact of hedging activities	$39.72	$42.19
Average sales price per Boe, including impact of hedging activities (2)	$35.67	$38.23

(2) The impact of hedging includes the gain (loss) on commodity derivative contracts settled during the periods presented.

(3)The three and six months ended June 30, 2014 include a one-time adjustment to production taxes, lease operating expenses and transportation, treating and gathering related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, production taxes, lease operating expenses and transportation, treating and gathering per Boe would have been as follows:

	For the Three Months Ended June 30, 2014	For the Six Months Ended June 30, 2014
Selected operating expenses per Boe:		
Production taxes	$1.69	$1.93
Lease operating expenses	$5.88	$5.26
Transportation, treating and gathering	$0.65	$0.69

(4) Lease operating expenses for the three and six months ended June 30, 2015 include $1.4 million and $2.8 million, respectively, of workover expense for one-time production enhancing workovers completed on certain WEHLU wells. Excluding workover expense, lease operating expense per Boe for the three and six months ended June 30, 2015 would have been $4.64 per Boe and $4.38 per Boe, respectively, compared to $5.60 per Boe and $5.12 per Boe for the three and six months ended June 30, 2014, respectively.

(5)Production costs include lease operating expenses, insurance, gathering and workover expense and excludes ad valorem and severance taxes. Excluding the arbitration settlement adjustment impact, production costs for the three and six months ended June 30, 2014 would have been as follows:

	For the Three Months Ended June 30, 2014	For the Six Months Ended June 30, 2014
Selected operating expenses per Boe:		
Production costs	$6.30	$5.70

Three Months Ended June 30, 2015 compared to the Three Months Ended June 30, 2014

Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) were $23.7 million for the three months ended June 30, 2015, down 47% from $44.8 million for the three months ended June 30, 2014. The decrease in revenues was the result of a 64% decrease in weighted average realized prices offset by a 47% increase in production. In addition to overall adverse commodity price conditions, we continue to be impacted by significant negative gas basis differentials in Appalachia and weakened NGLs pricing. Excluding the $10.6 million benefit of a one-time revenue adjustment related to an arbitration settlement for the three months ended June 30, 2014, weighted average Boe realized prices decreased 53% for the three months ended June 30, 2015 compared to the three months ended June 30, 2014. Average daily production on an equivalent basis was 13.9 MBoe/d for the three months ended June 30, 2015 compared to 9.5 MBoe/d for the same period in 2014. Oil, condensate and NGLs production represented approximately 53% of total production for the three months ended June 30, 2015 compared to 48% of total production for the three months ended June 30, 2014. The one-time arbitration settlement did not have any impact on second quarter 2014 production volumes.

Table of Contents

Oil and condensate revenues represented approximately 74% of our total oil, condensate, natural gas and NGLs revenues for the three months ended June 30, 2015 compared to 50% for the three months ended June 30, 2014. Total liquids revenues (oil, condensate and NGLs) represented approximately 83% of our total oil, condensate, natural gas and NGLs revenues for the three months ended June 30, 2015 compared to 61% for the three months ended June 30, 2014. Excluding a one-time adjustment related to an arbitration settlement, liquids revenues represented approximately 72% of our total oil, condensate, natural gas and NGLs revenues for the three months ended June 30, 2014. We continue to focus our drilling activity in the Mid-Continent oil play due to continued weakened natural gas and NGLs prices in the Appalachian Basin. Our average realized sales prices per Boe in the Appalachian Basin, excluding the impact of hedging activities and the one-time adjustment related to an arbitration settlement in 2014, were $4.98 per Boe for the second quarter of 2015 compared to $23.26 per Boe for the second quarter of 2014 and to $10.34 per Boe for the first quarter of 2015. Appalachian Basin prices have continued to decline subsequent to June 30, 2015. We expect our liquids revenues to continue to grow and be a significant percentage of total oil, condensate, natural gas and NGLs revenues during the remainder of 2015.

During the three months ended June 30, 2015, we had commodity derivative contracts covering approximately 31% of our oil and condensate production. The impact of hedging on oil and condensate sales during the three months ended June 30, 2015 was an increase of $1.7 million in oil and condensate revenues and resulted in an increase in total price realized from $47.68 per Bbl to $52.20 per Bbl. The gain on oil and condensate commodity derivatives contracts settled during the period includes a loss of $10,000 for amortization of prepaid premiums and a loss of $294,000 related to deferred put premiums. During the three months ended June 30, 2014, the impact of hedging on oil and condensate sales was a decrease of $1.1 million in oil and condensate revenues, which resulted in a decrease in total price realized from $108.06 per Bbl to $102.52 per Bbl. Excluding the benefit of the one-time revenue adjustment related to an arbitration settlement, the total price realized for oil and condensate including the loss on oil and condensate commodity derivatives contracts settled during the quarter ended June 30, 2014 would have decreased from $92.84 per Bbl to $87.30 per Bbl. For both periods, we designated 50% of our current crude hedges as price protection for our NGLs production.

During the three months ended June 30, 2015, we had commodity derivative contracts covering approximately 70% of our natural gas production, which resulted in a gain on natural gas commodity derivatives contracts settled during the quarter of $2.0 million and resulted in an increase in total price realized from $1.10 per Mcf to $1.68 per Mcf. The gain on natural gas commodity derivative contracts settled during the period includes a gain of $19,000 for amortization of prepaid premiums. Excluding the non-cash amortization, the impact of hedging on natural gas sales was an increase in revenues of $2.0 million of NYMEX hedge gains and $57,000 of basis hedge gains. During the three months ended June 30, 2014, the impact of hedging on natural gas sales was a decrease of $1.3 million in natural gas revenues resulting in a decrease in total price realized from $6.55 per Mcf to $6.06 per Mcf. Excluding the benefit of the one-time revenue adjustment related to an arbitration settlement, the total price realized for natural gas including the loss on natural gas commodity derivatives contracts settled during the quarter ended June 30, 2014 would have decreased from $3.52 per Mcf to $3.03 per Mcf.

During the three months ended June 30, 2015, we had commodity derivative contracts covering approximately 47% of our NGLs production. The impact of hedging on NGLs sales during the three months ended June 30, 2015 was an increase of $2.3 million in NGLs revenues and resulted in an increase in total price realized from $7.34 per Bbl to $14.97 per Bbl. The gain on NGLs commodity derivatives contracts settled during the period includes a loss of $10,000 for amortization of prepaid premiums and a loss of $294,000 related to deferred put premiums. During the three months ended June 30, 2014, the impact of hedging on NGLs sales was a decrease of $1.0 million in NGLs revenues which resulted in a decrease in total price realized from $23.62 per Bbl to $18.66 per Bbl. Excluding the impact of the one-time revenue adjustment related to an arbitration settlement, the total price realized for NGLs including the loss on NGLs commodity derivatives contracts settled during the quarter ended June 30, 2014 would have decreased from $26.88 per Bbl to $21.92 per Bbl.

The change in mark to market value for outstanding commodity derivatives contracts for the three months ended June 30, 2015 was a loss of $7.8 million compared to a loss of $5.4 million for the three months ended June 30, 2014. The change in the mark to market value is primarily the result of lower future commodity price curves and the

changes in hedge contracts during the period compared to the prior year.
For additional information regarding our oil and condensate hedging positions as of June 30, 2015, see Part I, Item 1. "Financial Statements, Note 6 – Derivative Instruments and Hedging Activity" of this report.
Production taxes. We reported production taxes of $822,000 for the three months ended June 30, 2015 compared to $2.0 million for the three months ended June 30, 2014. Production taxes reported for the three months ended June 30, 2014 include $584,000 of additional production taxes attributed to a one-time revenue adjustment resulting from an arbitration settlement. The remaining decrease in production taxes primarily resulted from lower commodity prices related to our Marcellus Shale properties. Production taxes for the three months ended June 30, 2015 and 2014 were approximately 3.5% and 4.5%, respectively, of oil, condensate, natural gas and NGLs revenues. The decrease in the production tax as a percentage of revenues is primarily the result of an increase in Mid-Continent revenues that benefit from an initial four-year production tax abatement reducing the rate from 7% to 1% on new horizontal wells drilled. Effective July 1, 2015, the production tax abatement on new

Table of Contents

horizontal wells drilled was reduced to an initial three-year production abatement period and the rate was reduced from 7% to 2%.

Lease operating expenses. We reported lease operating expenses ("LOE") of $7.2 million for the three months ended June 30, 2015 compared to $4.9 million for the three months ended June 30, 2014. Our total LOE was $5.74 per Boe for the three months ended June 30, 2015 compared to $5.66 per Boe for the same period in 2014. Excluding $185,000 of a one-time reduction to LOE related to an arbitration settlement, our total LOE would have been $5.88 per Boe for the quarter ended June 30, 2014. The increase in our LOE was primarily due to a $1.3 million increase in one-time workover expense for production enhancing workovers completed on certain WEHLU wells, a $449,000 increase in insurance expense and an increase in costs as a result of higher production volumes. Excluding workover expense and the 2014 arbitration settlement impact, LOE per Boe for the three months ended June 30, 2015 was $4.64 compared to $5.82 for the three months ended June 30, 2014.

Transportation, treating and gathering. We reported transportation expenses of $542,000 for the three months ended June 30, 2015 compared to $2.1 million for the three months ended June 30, 2014. Transportation, treating and gathering expense reported for the three months ended June 30, 2014 includes $1.6 million of expenses attributed to a one-time adjustment related to an arbitration settlement. Excluding the one-time adjustment, prior year second quarter transportation expenses would have been $562,000.

Depreciation, depletion and amortization. We reported depreciation, depletion and amortization ("DD&A") expense of $16.1 million for the three months ended June 30, 2015 up from $10.3 million for the three months ended June 30, 2014. The increase in DD&A expense was the result of a 47% increase in production and a 7% increase in the DD&A rate per Boe. The DD&A rate for the three months ended June 30, 2015 was $12.74 per Boe compared to $11.94 per Boe for the same period in 2014. The increase in the rate is primarily due to lower proved reserve volumes as a result of the lower economic limits or undeveloped reserves rendered non-economic due to lower oil and natural gas product prices.

Impairment of oil and natural gas properties. We reported an impairment of oil and natural gas properties of $100.2 million for the three months ended June 30, 2015. The impairment is the result of a 17% decline in the 12-month average natural gas price and a 28% decline in the 12-month average oil price used in the calculation of the full cost ceiling test at June 30, 2015 compared to June 30, 2014. See our discussion below under "- Results of Operations - Six Months Ended June 30, 2015 compared to the Six Months Ended June 30, 2014 - Impairment of oil and natural gas properties" for a discussion of the likelihood of future impairment charges in 2015 and the impact of recent price declines on such impairments.

General and administrative expense. We reported general and administrative expenses of $4.4 million for the three months ended June 30, 2015 compared to $3.9 million for the three months ended June 30, 2014. Non-cash stock-based compensation expense, which is included in general and administrative expense, was $1.2 million for the three months ended June 30, 2015 and $1.0 million for the three months ended June 30, 2014. Excluding stock-based compensation expense, general and administrative expense increased $280,000 to $3.2 million for the three months ended June 30, 2015 compared to the three months ended June 30, 2014. This increase is primarily due to higher legal costs.

Dividends on preferred stock. We reported dividends on preferred stock of $3.6 million for the three months ended June 30, 2015 and 2014. The Series A Preferred Stock had a stated value and liquidation preference of approximately $101.1 million at June 30, 2015 and 2014, respectively, and carries a cumulative dividend rate of 8.625% per annum. Dividends on the Series A Preferred Stock were $2.2 million for the three months ended June 30, 2015 and 2014, respectively. The Series B Preferred Stock had a stated value and liquidation preference of $53.5 million at June 30, 2015 and 2014 and carries a cumulative dividend rate of 10.75% per annum. Dividends on the Series B Preferred Stock were $1.4 million for the three months ended June 30, 2015 and 2014, respectively. Based on the number of shares of Series A Preferred Stock and Series B Preferred Stock outstanding at June 30, 2015, our future stated preferred dividend expense is approximately $3.6 million per quarter, which is subject to being declared and paid monthly.

Six Months Ended June 30, 2015 compared to the Six Months Ended June 30, 2014

Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) were $47.9 million for the six months ended June 30, 2015, down 43% from $83.6 million for the six months ended June 30, 2014. The decrease in revenues was the result of a 59% decrease in weighted average realized prices offset by a 38% increase in production. In addition to overall adverse commodity price conditions, we continue to be impacted by significant negative gas basis differentials in Appalachia and weakened NGLs pricing due to excess supply. Excluding the benefit of a one-time revenue adjustment of $10.6 million related to an arbitration settlement for the six months ended June 30, 2014, weighted average Boe realized prices decreased 53% for the six months ended June 30, 2015 compared to the six months ended June 30, 2014. Average daily production on an equivalent basis was 13.2 MBoe/d for the six months ended June 30, 2015 compared to 9.6 MBoe/d for the same period in 2014. Oil, condensate and NGLs production represented approximately 52% of total production for the six months ended June 30, 2015 compared to 45% of total production for the six months ended June 30, 2014. The one-time arbitration settlement did not have any impact on year-to-date June 30, 2014 production volumes.

Table of Contents

Oil and condensate revenues represented approximately 69% of our total oil, condensate, natural gas and NGLs revenues for the six months ended June 30, 2015 compared to 47% for the six months ended June 30, 2014. Total liquids revenues (oil, condensate and NGLs) represented approximately 78% of our total oil, condensate, natural gas and NGLs revenues for the six month period ended June 30, 2015 compared to 61% for the six month period ended June 30, 2014. Excluding a one-time adjustment related to an arbitration settlement, liquids revenues represented approximately 66% of our total oil, condensate, natural gas and NGLs revenues for the six month period ended June 30, 2014. We continue to focus our drilling activity in the Mid-Continent oil play due to continued weakened natural gas and NGLs prices in the Appalachian Basin. Our average realized sales prices per Boe in the Appalachian Basin, excluding the impact of hedging activities and the one-time adjustment related to an arbitration settlement in 2014, were $7.48 per Boe for the six months ended June 30, 2015 compared to $29.14 per Boe for the six months ended June 30, 2014. Appalachian Basin prices have continued to decline subsequent to June 30, 2015. We expect our liquids revenues to continue to grow and be a significant percentage of total oil, condensate, natural gas and NGLs revenues during the remainder of 2015.

During the six months ended June 30, 2015, we had commodity derivative contracts covering approximately 27% of our oil and condensate production. The impact of hedging on oil and condensate sales during the six months ended June 30, 2015 was an increase of $3.7 million in oil and condensate revenues and resulted in an increase in total price realized from $44.76 per Bbl to $49.86 per Bbl. The gain on oil and condensate commodity derivatives contracts settled during the period includes a loss of $21,000 for amortization of prepaid premiums and a loss of $585,000 related to deferred put premiums. During the six months ended June 30, 2014, the impact of hedging on oil and condensate sales was a decrease of $1.8 million in oil and condensate revenues, which resulted in a decrease in total price realized from $95.45 per Bbl to $91.15 per Bbl. Excluding the benefit of a one-time revenue adjustment related to an arbitration settlement during the six months ended June 30, 2014, the total price realized for oil and condensate including the loss on oil and condensate commodity derivatives contracts settled during the six months ended June 30, 2014 would have decreased from $87.77 per Bbl to $83.47 per Bbl. For both periods, we designated 50% of our current crude hedges as price protection for our NGLs production.

During the six months ended June 30, 2015, we had commodity derivative contracts covering approximately 63% of our natural gas production, which resulted in a gain on natural gas commodity derivatives contracts settled during the six months ended June 30, 2015 of $3.9 million and resulted in an increase in total price realized from $1.55 per Mcf to $2.11 per Mcf. The gain on natural gas commodity derivative contracts settled during the period includes a gain of $11,000 for amortization of prepaid premiums. Excluding the non-cash amortization, the impact of hedging on natural gas sales was an increase in revenues of $3.8 million of NYMEX hedge gains and $67,000 of basis hedge gains. During the six months ended June 30, 2014, the impact of hedging on natural gas sales was a decrease of $3.4 million in natural gas revenues resulting in a decrease in total price realized from $5.73 per Mcf to $5.14 per Mcf. Excluding the benefit of the one-time revenue adjustment related to an arbitration settlement during the six months ended June 30, 2014, the total price realized for natural gas including the loss on natural gas commodity derivatives contracts settled during the six months ended June 30, 2014 would have decreased from $4.32 per Mcf to $3.73 per Mcf.

During the six months ended June 30, 2015, we had commodity derivative contracts covering approximately 43% of our NGLs production. The impact of hedging on NGLs sales during the six months ended June 30, 2015 was an increase of $4.4 million in NGLs revenues and resulted in an increase in total price realized from $8.29 per Bbl to $16.72 per Bbl. The gain on NGLs commodity derivatives contracts settled during the period includes a loss of $21,000 for amortization of prepaid premiums and a loss of $585,000 related to deferred put premiums. During the six months ended June 30, 2014, the impact of hedging on NGLs sales was a decrease of $1.7 million in NGLs revenues which resulted in a decrease in total price realized from $31.82 per Bbl to $27.20 per Bbl. Excluding the impact of the one-time revenue adjustment related to an arbitration settlement during the six months ended June 30, 2014, the total price realized for NGLs including the loss on NGLs commodity derivatives contracts settled during the six months ended June 30, 2014 would have decreased from $33.69 per Bbl to $29.07 per Bbl.

Losses related to the change in mark to market value for outstanding commodity derivatives contracts for the six months ended June 30, 2015 were $3.5 million compared to losses of $8.6 million for the six months ended June 30, 2014. The decrease in the mark to market loss is primarily the result of lower commodity prices and the changes in hedge contracts during the period.

For additional information regarding our oil and condensate hedging positions as of June 30, 2015, see Part I, Item 1. "Financial Statements, Note 6 – Derivative Instruments and Hedging Activity" of this report.

Production taxes. We reported production taxes of $1.7 million for the six months ended June 30, 2015 compared to $3.9 million for the six months ended June 30, 2014. Production taxes reported for the six months ended June 30, 2014 include $584,000 of additional production taxes attributed to a one-time revenue adjustment resulting from an arbitration settlement. Excluding the 2014 adjustment, the decrease in production taxes primarily resulted from lower commodity prices related to our Marcellus Shale properties. Production taxes for the six months ended June 30, 2015 and 2014 were approximately 3.5% and 4.7%, respectively, of oil, condensate, natural gas and NGLs revenues. The decrease in the production tax as a percentage of

Table of Contents

revenues is primarily the result of an increase in Mid-Continent revenues that benefit from an initial four-year production tax abatement reducing the rate from 7% to 1% on new horizontal wells drilled. Effective July 1, 2015, the production tax abatement on new horizontal wells drilled was reduced to an initial three-year production abatement period and the rate was reduced from 7% to 2%.

Lease operating expenses. We reported LOE of $13.3 million for the six months ended June 30, 2015 compared to $8.9 million for the six months ended June 30, 2014. Our total LOE was $5.53 per Boe for the six months ended June 30, 2015 compared to $5.15 per Boe for the same period in 2014. Excluding $185,000 of a one-time reduction to LOE related to an arbitration settlement during the six months ended June 30, 2014, our total LOE would have been $5.26 per Boe for the six months ended June 30, 2014. The increase in our LOE was primarily due to a $2.7 million increase in one-time workover expense for production enhancing workovers completed on certain WEHLU wells, a $703,000 increase in controllable LOE resulting from new wells and higher overall costs associated with producing oil versus natural gas, an increase in ad valorem taxes of $318,000 and a $425,000 increase in insurance costs. Excluding workover expense, LOE per Boe for the six months ended June 30, 2015 would have been $4.38 compared to $5.12 for the six months ended June 30, 2014.

Transportation, treating and gathering. We reported transportation expenses of $1.0 million for the six months ended June 30, 2015 compared to $2.8 million for the six months ended June 30, 2014. Transportation, treating and gathering expense reported for the six months ended June 30, 2014 includes $1.6 million of expense attributed to a one-time adjustment related to an arbitration settlement. Excluding the one-time adjustment, year to date June 30, 2014 transportation expense would have been $1.2 million.

Depreciation, depletion and amortization. We reported DD&A expense of $30.6 million for the six months ended June 30, 2015 up from $22.7 million for the six months ended June 30, 2014. The increase in DD&A expense was the result of a 38% increase in production partially offset by a 3% decrease in the DD&A rate per Boe. The DD&A rate for the six months ended June 30, 2015 was $12.75 per Boe compared to $13.09 per Boe for the same period in 2014. The decrease in the rate is primarily due to higher proved reserves at June 30, 2015 compared to June 30, 2014.

Impairment of oil and natural gas properties. We reported an impairment of oil and natural gas properties of $100.2 million for the three and six months ended June 30, 2015. The impairment is the result of a 17% decline in the 12-month average natural gas price and a 28% decline in the 12-month average oil price used in the calculation of our full cost ceiling test at June 30, 2015 compared to June 30, 2014. Sustained lower oil and natural gas prices experienced in the second half of 2014 and the current year will continue to impact our proved reserves and related PV-10 adversely as the prices used for such estimates under SEC rules are based on the trailing 12-month unweighted average commodities prices. Lower prices used in estimating proved reserves can result in a reduction in volumes and present value due to economic limits or render undeveloped reserves non-economic, which in turn, without significant additions to proved reserves, make it likely that we will incur significant additional future ceiling impairment charges against our oil and natural gas properties under full cost accounting in 2015. In light of the significantly lower oil and natural gas prices experienced in late 2014 and in the current year and because the ceiling impairment calculation requires a trailing 12-month unweighted average of commodities prices, we expect to have an additional significant ceiling test impairment during the third quarter of 2015. Assuming commodities prices do not increase dramatically in the last three months of this year, it is likely that we could incur an additional ceiling test impairment in the fourth quarter of 2015. The effects of lower quarter-over-quarter prices will result in ongoing impairments until prices stabilize over a 12-month period. At June 30, 2015, our ceiling test impairment calculation was based on SEC pricing of $3.39 per MMBtu of Henry Hub spot natural gas and $71.68 per barrel of West Texas Intermediate spot oil which compares to current trailing 12-month unweighted average commodity prices subsequent to quarter end $3.25 per MMBtu of Henry Hub spot natural gas and $67.65 per barrel of West Texas Intermediate spot oil.

General and administrative expense. We reported general and administrative expenses of $8.7 million for the six months ended June 30, 2015 and 2014, respectively. Non-cash stock-based compensation expense, which is included in general and administrative expense, increased $241,000 to $2.8 million for the six months ended June 30, 2015 compared to the six months ended June 30, 2014. Excluding stock-based compensation expense, general and administrative expense decreased $228,000 to $5.9 million for the six months ended June 30, 2015 compared to the six months ended June 30, 2014. This decrease is primarily due to lower legal fees.

Interest expense. We reported interest expense of $14.5 million for the six months ended June 30, 2015 compared to $13.8 million for the six months ended June 30, 2014. The increase in interest expense is primarily due to additional borrowings under the revolving credit facility.

Dividends on preferred stock. We reported dividends on preferred stock of $7.2 million for the six months ended June 30, 2015 and 2014, respectively. The Series A Preferred Stock had a stated value and liquidation preference of approximately $101.1 million at June 30, 2015 and 2014, respectively, and carries a cumulative dividend rate of 8.625% per annum. Dividends on the Series A Preferred Stock were $4.4 million and $4.3 million for the six months ended June 30, 2015 and 2014, respectively. The Series B Preferred Stock, issued during November 2013, had a stated value and liquidation preference of

Table of Contents

$53.5 million at June 30, 2015 and 2014, respectively, and carries a cumulative dividend rate of 10.75% per annum. Dividends on the Series B Preferred Stock were $2.9 million for the six months ended June 30, 2015 and 2014. Based on the number of shares of Series A Preferred Stock and Series B Preferred Stock outstanding at June 30, 2015, our future stated preferred dividend expense is approximately $3.6 million per quarter, which is subject to being declared and paid monthly.

Liquidity and Capital Resources

Overview. Our primary sources of liquidity and capital resources are internally generated cash flows from operating activities, availability under the Revolving Credit Facility, access to capital markets, to the extent available, and potential asset sales. We believe that the funds from operating cash flows, available borrowings under our Revolving Credit Facility and proceeds from capital markets transactions and asset sales should be sufficient to meet our cash requirements for at least the next 12 months. We continually evaluate our capital needs and compare them to our capital resources and ability to raise funds in the financial markets. We adjust capital expenditures in response to changes in oil, condensate, natural gas and NGLs prices, drilling results and cash flow.

For the six months ended June 30, 2015, we reported cash flows provided by operating activities of $37.0 million. For the six months ended June 30, 2015, we reported net cash used in investing activities of $79.2 million primarily for the development of oil and natural gas properties of $84.7 million offset by $6.6 million received as a deposit in connection with our Mid-Continent divestiture. For the six months ended June 30, 2015, we reported net cash provided by financing activities of $40.5 million, consisting primarily of $50.0 million of net borrowings under our Revolving Credit Facility partially offset by $7.2 million of preferred stock dividends paid and $1.4 million of tax withholding related to restricted stock and PBU vestings during the period. As a result of these activities, our cash and cash equivalents balance decreased by $1.6 million, resulting in a cash and cash equivalents balance of $9.4 million at June 30, 2015.

At June 30, 2015, we had a net working capital deficit of approximately $1.4 million. At June 30, 2015, availability under our Revolving Credit Facility was $105.0 million.

Future capital and other expenditure requirements. Capital expenditures for the remainder of 2015, excluding acquisitions, are currently projected to be approximately $41.0 million, resulting in a total capital expenditures budget of approximately $120.0 million for 2015. In the Appalachian Basin and Mid-Continent, we expect to spend $6.3 million and $31.4 million, respectively, for drilling, completion, infrastructure, lease acquisition and seismic costs. In addition, we have allocated $3.3 million for capitalized interest and other costs. We plan to fund our remaining 2015 capital budget through existing cash balances, internally generated cash flow from operating activities, borrowings under the Revolving Credit Facility and possible capital markets transactions and divestitures of assets, or some combination thereof.

We are closely monitoring the recent volatility in the commodity markets, in particular the recent drop in oil and NGLs prices and the continued widening of basis differentials in Appalachia, and we are developing capital plans responsive to changes that are occurring in the commodity and capital markets. Our capital expenditures and the scope of our drilling activities may change as a result of several factors, including, but not limited to, changes in oil, condensate, natural gas and NGLs prices, costs of drilling and completion and leasehold acquisitions, drilling results, and changes in the borrowing base under the Revolving Credit Facility. We operate approximately 100% of our remaining budgeted 2015 capital expenditures, and thus, if necessary, we could reduce a significant portion of our remaining 2015 planned capital expenditures, if necessary, to better match available capital resources.

Operating cash flow and commodity hedging activities. Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for oil, condensate, natural gas and NGLs. Prices for these commodities are determined primarily by prevailing market conditions including national and worldwide economic activity, weather, infrastructure capacity to reach markets, supply levels and other variable factors. These factors are beyond our control and are difficult to predict.

To mitigate some of the potential negative impact on cash flows caused by changes in oil, condensate, natural gas and NGLs prices, we have entered into financial commodity costless collars, index swaps, basis and fixed price swaps and put and call options to hedge oil, condensate, natural gas and NGLs price risk. The crude oil fixed price swaps provide price protection for our future oil sales and butane, isobutene and pentanes components of our NGLs production as these heavy components of NGLs have pricing that correlates closely with oil pricing. We have designated 50% of our current crude hedges as price protection for a portion of our NGLs production. For additional information regarding our hedging activities, see Part I, Item 1. “Financial Statements, Note 6 – Derivative Instruments and Hedging Activity” of this report.

At June 30, 2015, the estimated fair value of all of our commodity derivative instruments was a net asset of $22.4 million, comprised of current and non-current assets and liabilities. By removing the price volatility from a portion of our oil, condensate, natural gas and NGLs sales for 2015 through 2018, we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flows for those periods. While mitigating negative effects of falling commodity prices, certain derivative contracts also limit the benefits we could receive from increases in commodity prices. In conjunction with

Table of Contents

certain commodity derivative hedging activity, we deferred the payment of certain put premiums for the production month period July 2015 through August 2018. At June 30, 2015, we had a current commodity premium payable of $1.5 million and a long-term commodity premium payable of $4.1 million. The put premium liabilities become payable monthly as the hedge production month becomes the prompt production month.

As of June 30, 2015, all of our commodity derivative hedge positions were with a multinational energy company or large financial institutions, each of which is not known to us to be in default on their derivative positions. We are exposed to credit risk to the extent of non-performance by the counterparties in the derivative contracts discussed above; however, we do not anticipate non-performance by such counterparties.

ATM Program. We have an at-the-market equity offering program (the “ATM Program”) pursuant to which we may issue and sell shares of our common stock having an aggregate offering price up to $50.0 million in amounts and at times as we determine from time to time. Actual issuances, if any, will depend on a variety of factors to be determined by us, including, among others, market conditions, the trading price of our common stock, our determinations of the appropriate sources of funding for our company and potential uses of funding available to us. During the three months ended June 30, 2015, we did not issue any shares of common stock under the ATM Program.

Revolving Credit Facility. Our Revolving Credit Facility provides for a maximum amount of $500.0 million, subject to a borrowing base, which, at June 30, 2015, was $200.0 million. At June 30, 2015, we had $95.0 million of borrowings outstanding under our Revolving Credit Facility. As of August 3, 2015, we had $60.0 million of borrowings outstanding under our Revolving Credit Facility.

At June 30, 2015, we were in compliance with all financial covenants under the Revolving Credit Facility. For a more detailed description of the terms of our Revolving Credit Facility, see Part I, Item 1. “Financial Statements, Note 4 – Long-Term Debt” of this report.

Senior Secured Notes. We have $325.0 million of senior secured notes outstanding, which are due May 15, 2018. For a more detailed description of the terms of our Notes, see Part I, Item 1. “Financial Statements, Note 4 - Long-Term Debt - Senior Secured Notes” of this report. At June 30, 2015, we were in compliance with all covenants under the indenture governing the Notes.

Series A Preferred Stock. We pay cumulative dividends on the Series A Preferred Stock at a fixed rate of 8.625% per annum of the aggregate $101.1 million stated value and liquidation preference. For the three and six months ended June 30, 2015, we recognized dividend expense of $2.2 million and $4.4 million, respectively, for the Series A Preferred Stock.

Series B Preferred Stock. We pay cumulative dividends on the Series B Preferred Stock at a fixed rate of 10.75% per annum of the aggregate $53.5 million stated value and liquidation preference. For the three and six months ended June 30, 2015, we recognized dividend expense of $1.4 million and $2.9 million, respectively, for the Series B Preferred Stock.

Off-Balance Sheet Arrangements

As of June 30, 2015, we had no off-balance sheet arrangements. We have no plans to enter into any off-balance sheet arrangements in the foreseeable future.

Commitments and Contingencies

As is common within the industry, we have entered into various commitments and operating agreements related to the exploration and development of and production from proved oil and natural gas properties. It is management’s belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

We are party to various litigation matters and administrative claims arising out of the normal course of business. Although the ultimate outcome of each of these matters cannot be absolutely determined and the liability the Company may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters, management does not believe any such matters will have a material adverse effect on our financial position, results of operations or cash flows. A discussion of current legal proceedings is set forth in Part I, Item 1. “Financial Statements, Note 11 – Commitments and Contingencies” of this report.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses, contingent assets and liabilities and the related disclosures in the accompanying condensed consolidated financial statements. Changes in these estimates and assumptions could materially affect our financial position, results of operations or cash flows. Management considers an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and

Table of Contents

- Changes in the estimate or different estimates could have a material impact on our consolidated results of operations or financial condition.

Significant accounting policies that we employ and information about the nature of our most critical accounting estimates, our assumptions or approach used and the effects of hypothetical changes in the material assumptions used to develop each estimate are presented in Part I, Item I. “Financial Statements, Note 2 – Summary of Significant Accounting Policies” of this report and in Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates” included in our 2014 Form 10-K.

Recent Accounting Developments

For a discussion of recent accounting developments, see Part I, Item 1. “Financial Statements, Note 2 – Summary of Significant Policies” of this report.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Our major commodity price risk exposure is to the prices received for our oil, condensate, natural gas and NGLs production. Our results of operations and operating cash flows are affected by changes in market prices. Realized commodity prices received for our production are the spot prices applicable to oil, condensate, natural gas and NGLs in the region produced. Prices received for oil, condensate, natural gas and NGLs are volatile, unpredictable and beyond our control. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. For the three and six months ended June 30, 2015, a 10% change in the prices received for oil, condensate, natural gas and NGLs production would have had an approximate $2.4 million and $4.8 million, impact on our revenues prior to hedge transactions to mitigate our commodity pricing risk, respectively. See Part I, Item 1. “Financial Statements, Note 6 – Derivative Instruments and Hedging Activity” of this report for additional information regarding our hedging activities.

Interest Rate Risk

We are exposed to changes in interest rates as a result of our Revolving Credit Facility. At June 30, 2015, we had $95.0 million of borrowings outstanding under our Revolving Credit Facility. We have not entered into interest rate hedging arrangements in the past, and have no current plans to do so. Due to the potential for fluctuating balances in the amount outstanding under our Revolving Credit Facility, we do not believe such arrangements to be cost effective. The amount outstanding under the Notes is at fixed interest of 8.625% per annum. We currently do not use interest rate derivatives to mitigate our exposure to the volatility in interest rates, including under the Revolving Credit Facility, as this risk is minimal.

Item 4. Controls and Procedures

Management’s Evaluation on the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (“Exchange Act”), as of June 30, 2015. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of June 30, 2015, our disclosure controls and procedures were effective in providing reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended June 30, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

41

Table of Contents

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

A discussion of current legal proceedings is set forth in Part I, Item 1. “Financial Statements, Note 11 – Commitments and Contingencies” of this report.

Item 1A. Risk Factors

Information about material risks related to our business, financial condition and results of operations for the three and six months ended June 30, 2015 does not materially differ from that set out under Part I, Item 1A. “Risk Factors” in our 2014 Form 10-K. You should carefully consider the risk factors and other information discussed in our 2014 Form 10-K, as well as the information provided in this report. These risks are not the only risks facing our Company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, operating results and cash flows.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosure

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

The exhibits required to be filed or furnished pursuant to the requirements of Item 601 of Regulation S-K are set forth in the Exhibit Index accompanying this Form 10-Q and are incorporated herein by reference.

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.

	GASTAR EXPLORATION INC.
Date: August 6, 2015	By: /S/ J. RUSSELL PORTER J. Russell Porter President and Chief Executive Officer (Duly authorized officer and principal executive officer)
Date: August 6, 2015	By: /S/ MICHAEL A. GERLICH Michael A. Gerlich Senior Vice President and Chief Financial Officer (Duly authorized officer and principal financial and accounting officer)

Table of Contents

EXHIBIT INDEX

Exhibit Number	Description
2.1	Amended and Restated Plan of Arrangement Under Section 193 of the Business Corporations Act (Alberta), effective as of November 14, 2013 (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on November 15, 2013. File No. 001-32714).
2.2	Agreement and Plan of Merger, dated as of January 31, 2014, among Gastar Exploration, Inc. and Gastar Exploration USA, Inc. (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on January 31, 2014. File No. 000-55138).
2.3**	Purchase and Sale Agreement, dated May 1, 2015, by and between Gastar Exploration Inc. and Oklahoma Energy Acquisitions, LP. (incorporated by reference to Exhibit 2.3 of the Quarterly Report on Form 10-Q filed with the SEC on May 7, 2015).
2.4†	First Amendment of Purchase and Sale Agreement, dated June 22, 2015, by and between Gastar Exploration Inc. and Oklahoma Energy Acquisitions, LP.
3.1	Amended and Restated Certificate of Incorporation of Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.) (incorporated by reference to Exhibit 3.1 of the Current Report on Form 8-K filed with the SEC on October 28, 2013. File No. 001-35211).
3.2	Second Amended and Restated Bylaws of Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.) (incorporated by reference to Exhibit 3.2 of the Current Report on Form 8-K filed with the SEC on October 28, 2013. File No. 001-35211).
3.3	Certificate of Merger of Gastar Exploration, Inc. into Gastar Exploration USA, Inc. (incorporated by reference to Exhibit 3.1 of the Current Report on Form 8-K filed with the SEC on January 31, 2014. File No. 000-55138).
3.4	Certificate of Designation of Rights and Preferences of 8.625% Series A Cumulative Preferred Stock (incorporated by reference to Exhibit 3.3 of Gastar Exploration USA, Inc.'s Form 8-A filed on June 20, 2011. File No. 001-35211).
3.5	Certificate of Designation of Rights and Preferences of 10.75% Series B Cumulative Preferred Stock (incorporated by reference to Exhibit 3.4 of the Form 8-A filed with the SEC on November 1, 2013. File No. 001-35211).
31.1†	Certification of Principal Executive Officer of Gastar Exploration Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2†	

	Certification of Principal Financial Officer of Gastar Exploration Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1††	Certification of Principal Executive Officer and Principal Financial Officer of Gastar Exploration Inc. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS†	XBRL Instance Document
101.SCH†	XBRL Taxonomy Extension Schema Document
101.CAL†	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF†	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB†	XBRL Taxonomy Extension Label Linkbase Document
101.PRE†	XBRL Taxonomy Extension Presentation Linkbase Document

Table of Contents

---

† Filed herewith.

†† By SEC rules and regulations, deemed not filed for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, nor shall it be deemed incorporated by reference into any filing under the Securities Act, or the Exchange Act.

* Management plan or compensatory plan or arrangement.

** Pursuant to Item 601(b)(2) of Regulation S-K, the schedules and similar attachments to Exhibit 2.3 have not been filed herewith. The registrant agrees to furnish supplementally a copy of any omitted schedule to the Securities and Exchange Commission upon request.

45