GASTAR EXPLORATION INC.

FORM 10-Q
(Quarterly Report)

Filed 11/08/17 for the Period Ending 09/30/17

Address	1331 LAMAR STREET SUITE 650 HOUSTON, TX, 77010
Telephone	7137391800
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Symbol	GST
SIC Code	1311 - Crude Petroleum and Natural Gas
Industry	Oil & Gas Exploration and Production
Sector	Energy
Fiscal Year	12/31

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

FORM 10-Q

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

FOR THE QUARTERLY PERIOD ENDED September 30, 2017

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

FOR THE TRANSITION PERIOD FROM _____TO ______

Commission File Number: 001-35211

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐
Emerging growth company	☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

The total number of outstanding shares of common stock, $0.001 par value per share, as of November 6, 2017 was 218,941,521.

GASTAR EXPLORATION INC.
QUARTERLY REPORT ON FORM 10-Q
FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2017
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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.

Glossary of Terms

AMI	Area of mutual interest, an agreed designated geographic area where co-participants or other industry participants 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
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	One million British thermal units
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
PUD	Proved undeveloped reserves
STACK Play	An acronymic name for a predominantly oil producing play referring to the exploration and development of the Sooner Trend of the Anadarko Basin in Canadian and Kingfisher Counties, Oklahoma. References to the STACK Play is extended to adjacent counties.
U.S.	United States of America

U.S. GAAP	Accounting principles generally accepted in the United States of America
WTI	West Texas Intermediate

PART I. FINANCI AL INFORMATION

Item 1. Financial Statements

GASTAR EXPLORATION INC.
CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2017	December 31, 2016
	(Unaudited)	
	(in thousands, except share and per share data)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 29,229	$ 71,529
Accounts receivable, net of allowance for doubtful accounts of $1,953, respectively	40,353	26,883
Commodity derivative contracts	4,400	6,212
Prepaid expenses	1,167	755
Total current assets	75,149	105,379
PROPERTY, PLANT AND EQUIPMENT:		
Oil and natural gas properties, full cost method of accounting:		
Unproved properties, excluded from amortization	135,945	67,333
Proved properties	1,303,165	1,253,061
Total oil and natural gas properties	1,439,110	1,320,394
Furniture and equipment	3,031	2,622
Total property, plant and equipment	1,442,141	1,323,016
Accumulated depreciation, depletion and amortization	(1,147,774)	(1,131,012)
Total property, plant and equipment, net	294,367	192,004
OTHER ASSETS:		
Restricted cash	370	—
Commodity derivative contracts	416	1,638
Deferred charges, net	—	676
Advances to operators and other assets	100	102
Other	405	405
Total other assets	1,291	2,821
TOTAL ASSETS	$ 370,807	$ 300,204
LIABILITIES AND STOCKHOLDERS' DEFICIT		
CURRENT LIABILITIES:		
Accounts payable	$ 11,411	$ 8,867
Revenue payable	16,428	6,690
Accrued interest	7,271	3,515
Accrued drilling and operating costs	12,100	2,615
Advances from non-operators	1,589	3,504
Commodity derivative contracts	326	338
Commodity derivative premium payable	1,337	1,654
Asset retirement obligation	—	89
Other accrued liabilities	2,791	2,462
Total current liabilities	53,253	29,734
LONG-TERM LIABILITIES:		
Long-term debt	333,593	404,493
Commodity derivative contracts	129	—
Commodity derivative premium payable	34	969
Asset retirement obligation	4,574	5,443
Total long-term liabilities	338,330	410,905
Commitments and contingencies (Note 11)		
STOCKHOLDERS' DEFICIT:		
Preferred stock, par value $0.01 per share, 40,000,000 shares authorized		
8.625% Series A Cumulative Preferred Stock, 10,000,000 shares designated; 4,045,000 shares issued and outstanding at September 30, 2017 and December 31, 2016, respectively, with liquidation preference of $25.00 per share	41	41
10.75% Series B Cumulative Preferred Stock, 10,000,000 shares designated; 2,140,000 shares issued and outstanding at September 30, 2017 and December 31, 2016, respectively, with liquidation preference of $25.00 per share	21	21
Common stock, par value $0.001 per share; 800,000,000 and 550,000,000 shares authorized at September 30, 2017 and December 31, 2016, respectively; 218,946,763 and 150,377,870 shares issued and outstanding at September 30, 2017 and December 31, 2016, respectively	219	150
Additional paid-in capital	817,627	644,306
Accumulated deficit	(838,684)	(784,953)
Total stockholders' deficit	(20,776)	(140,435)
TOTAL LIABILITIES AND STOCKHOLDERS' DEFICIT	$ 370,807	$ 300,204

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands, except share and per share data)			
REVENUES:				
Oil and condensate	$ 12,952	$ 10,306	$ 37,886	$ 30,464
Natural gas	2,519	2,500	7,452	8,394
NGLs	2,757	1,695	7,527	5,100
Total oil, condensate, natural gas and NGLs revenues	18,228	14,501	52,865	43,958
(Loss) gain on commodity derivatives contracts	(2,896)	(1,498)	3,782	(3,991)
Total revenues	15,332	13,003	56,647	39,967
EXPENSES (BENEFIT):				
Production taxes	721	400	1,675	1,469
Lease operating expenses	6,178	5,166	16,396	15,829
Transportation, treating and gathering	436	338	1,187	1,346
Depreciation, depletion and amortization	6,059	5,223	16,762	24,543
Impairment of oil and natural gas properties	—	—	—	48,497
Accretion of asset retirement obligation	62	92	171	286
General and administrative expense	4,067	3,925	12,482	15,872
Litigation settlement benefit	—	(10,100)	—	(10,100)
Total expenses	17,523	5,044	48,673	97,742
(LOSS) INCOME FROM OPERATIONS	(2,191)	7,959	7,974	(57,775)
OTHER INCOME (EXPENSE):				
Interest expense	(10,159)	(8,178)	(29,744)	(26,739)
Loss on early extinguishment of debt	—	—	(12,172)	—
Investment income and other (expense)	51	41	166	(2)
LOSS BEFORE PROVISION FOR INCOME TAXES	(12,299)	(178)	(33,776)	(84,516)
Provision for income taxes	—	—	—	—
NET LOSS	(12,299)	(178)	(33,776)	(84,516)
Dividends on preferred stock	(1,206)	—	(8,443)	(3,618)
Undeclared cumulative dividends on preferred stock	(2,412)	(3,618)	(2,412)	(7,237)
NET LOSS ATTRIBUTABLE TO COMMON STOCKHOLDERS	$ (15,917)	$ (3,796)	$ (44,631)	$ (95,371)
NET LOSS PER SHARE OF COMMON STOCK ATTRIBUTABLE TO COMMON STOCKHOLDERS:				
Basic	$ (0.08)	$ (0.03)	$ (0.23)	$ (0.92)
Diluted	$ (0.08)	$ (0.03)	$ (0.23)	$ (0.92)
WEIGHTED AVERAGE SHARES OF COMMON STOCK OUTSTANDING:				
Basic	209,072,232	129,301,817	190,745,688	104,125,317
Diluted	209,072,232	129,301,817	190,745,688	104,125,317

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 Nine Months Ended September 30,	
	2017	2016
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (33,776)	$ (84,516)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	16,762	24,543
Impairment of oil and natural gas properties	—	48,497
Stock-based compensation	3,990	3,145
Mark to market of commodity derivatives contracts:		
Total (gain) loss on commodity derivatives contracts	(3,782)	3,991
Cash settlements of matured commodity derivatives contracts, net	5,602	10,690
Cash premiums paid for commodity derivatives contracts	—	(565)
Amortization of deferred financing costs and debt discount	8,218	3,812
Accretion of asset retirement obligation	171	286
Settlement of asset retirement obligation	—	(87)
Loss on sale of furniture and equipment	—	97
Loss on early extinguishment of debt	12,172	—
Changes in operating assets and liabilities:		
Accounts receivable	(13,466)	3,861
Prepaid expenses	(412)	362
Accounts payable and accrued liabilities	13,657	7,656
Net cash provided by operating activities	9,136	21,772
CASH FLOWS FROM INVESTING ACTIVITIES:		
Development and purchase of oil and natural gas properties	(81,906)	(43,175)
(Acquisition of) refund for oil and natural gas properties	(54,462)	1,149
Proceeds from sale of oil and natural gas properties	28,798	77,499
Application of proceeds from non-operators	(1,915)	(57)
(Advances to) reimbursements from operators	(22)	211
(Purchase) sale of furniture and equipment	(409)	80
Net cash (used in) provided by investing activities	(109,916)	35,707
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from term loan	250,000	—
Proceeds from convertible notes	200,000	—
Repayment of senior secured notes	(325,000)	—
Repayment of revolving credit facility	(84,630)	(100,370)
Loss on early extinguishment of debt	(7,011)	—
Proceeds from issuance of common stock, net of issuance costs	56,366	44,815
Dividends on preferred stock	(19,298)	(3,618)
Deferred financing charges	(10,991)	(930)
Increase in restricted cash	(370)	—
Tax withholding related to restricted stock and performance based unit award vestings	(586)	(711)
Net cash provided by (used in) financing activities	58,480	(60,814)
NET DECREASE IN CASH AND CASH EQUIVALENTS	(42,300)	(3,335)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	71,529	50,074
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 29,229	$ 46,739

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

1. Description of Business

Gastar Exploration Inc. (the "Company" or "Gastar") is a pure play Mid-Continent independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and NGLs. 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. Gastar holds a concentrated acreage position in the normally pressured oil window of the STACK Play, an area of central Oklahoma which is home to multiple oil and natural gas-rich reservoirs including the Oswego limestone, Meramec and Osage bench formations within the Mississippi Lime, the Woodford shale and Hunton limestone formations.

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, 2016 (the "2016 Form 10-K") filed with the SEC. Please refer to the notes to the consolidated financial statements included in the 2016 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 2016 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 2016 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 valuation of convertible debt, 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.

The results of operations for the three and nine months ended September 30, 2017 are not necessarily indicative of the results that may be expected for the year ending December 31, 2017.

Subsequent Events

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.

Accounts Receivable

Accounts receivable are reported net of the allowance for doubtful accounts. The allowance for doubtful accounts is determined based on a review of the Company's receivables. Receivable accounts are charged off when collection efforts have failed or the account is deemed uncollectible. During 2016, the Company determined that a receivable account from a third-party natural gas and NGLs purchaser would no longer be collectible as a result of the third-party purchaser filing for bankruptcy. A summary of the activity related to the allowance for doubtful accounts is as follows:

	September 30, 2017	December 31, 2016
	(in thousands)	
Allowance for doubtful accounts, beginning of period	$ 1,953	$ —
Expense	—	1,953
Reductions/write-offs	—	—
Allowance for doubtful accounts, end of period	$ 1,953	$ 1,953

Recent Accounting Developments

Business Combinations. In January 2017, the FASB issued updated guidance to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The amendments in this update provide a screen to determine when a set is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. This screen reduces the number of transactions that need to be further evaluated. If the screen is not met, the amendments in this update (1) require that to be considered a business, a set must include, at a minimum, an input and a substantive process that together significantly contribute to the ability to create output and (2) remove the evaluation of whether a market participant could replace missing elements. The amendments in this update affect all reporting entities that must determine whether they have acquired or sold a business and are effective for public business entities for annual reporting periods beginning after December 15, 2017, including interim periods within those periods. The amendments should be applied prospectively on or after the effective date and no disclosures are required at transition. Early application is allowed as follows (1) for transactions for which the acquisition date occurs before the issuance date or effective date of the amendments, only when the transaction has not been reported in financial statements that have been issued or made available for issuance and (2) for transactions in which a subsidiary is deconsolidated or a group of assets is derecognized that occur before the issuance date or effective date of the amendments, only when the transaction has not been reported in financial statements that have been issued or made available for issuance. The application of this guidance to future acquisitions and disposals could have an effect on the Company's financial position or results of operations.

Statement of Cash Flows. In August 2016, the FASB issued updated guidance associated with the classification of certain cash receipts and cash payments on the statement of cash flows. The amended guidance addresses specific cash flow issues with the objective of reducing existing diversity in practice. The amendment provides guidance on the following eight specific cash flow issues: debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies; distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. The amendments in this update apply to all entities required to present a statement of cash flows. The amendments in this update are effective for public business entities for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years. Early adoption is permitted, including adoption in an interim period. If an entity early adopts the amendments in an interim period, any adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity that elects early adoption must adopt all of the amendments in the same period. Amendments should be applied using a retrospective transition method to each period presented. If it is impracticable to apply the amendments retrospectively for some of the issues, the amendments for those issues would be applied prospectively as of the earliest date practicable. The Company is currently evaluating the effect that adopting this guidance will have on its presentation of cash flows and does not believe the effects of adopting this updated guidance will have a material effect on its statement of cash flows nor that it will affect the Company's financial position or results of operations.

Compensation – Stock Compensation. In March 2016, the FASB issued updated guidance as part of its simplification initiative which is intended to simplify several aspects of the accounting for stock-based compensation transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. For public business entities, the amendments in this update are effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Amendments related to the timing of when excess tax benefits are recognized, minimum statutory withholding requirements, forfeitures, and intrinsic value should be applied using a modified retrospective transition method by means of a cumulative-effect adjustment to equity as of the beginning of the period in which the guidance is adopted. Amendments related to the presentation of employee taxes paid on the statement of cash flows when an employer withholds shares to meet the minimum statutory withholding requirement should be applied retrospectively. Amendments requiring recognition of excess tax benefits and tax deficiencies in the income statement and the practical expedient for estimating expected term should be applied prospectively. An entity may elect to apply the amendments related to the presentation of excess tax benefits on the statement of cash flows using either a prospective transition method or a retrospective transition method. The Company adopted this updated guidance for the fiscal year beginning January 1, 2017 and recorded a cumulative adjustment of approximately $657,000 to retained earnings to properly reflect the adjustment to stock compensation expense to reduce the forfeiture rate to 0%.

Leases. In February 2016, the FASB issued updated guidance to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and enhance disclosures regarding key information about leasing arrangements. Under the new guidance, lessees will be req uired to recognize a lease liability and a right-of-use asset for all leases. The new lease guidance also simplified the accounting for sale and leaseback transactions primarily because lessees must recognize lease assets and lease liabilities. The amendme nts in this update are effective beginning on January 1, 2019 and should be applied through a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financ ial statements. Early adoption is permitted. The Company has begun analyzing its lease contracts but has not yet determined what the effects of adopting this updated guidance will be on its consolidated financial statements.

Income Taxes. In November 2015, the FASB issued updated guidance as part of its simplification initiative for the presentation of deferred taxes. Current U.S. GAAP requires an entity to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified statement of financial position where such classification generally does not align with the time period in which the recognized deferred tax amounts are expected to be recovered or settled. To simplify the presentation of deferred income taxes, the amendments in this update require that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position and apply to all entities that present a classified statement of financial position, resulting in the alignment of the presentation of deferred income tax assets and liabilities with International Financial Reporting Standards. International Accounting Standard 1, *Presentation of Financial Statements* . This updated guidance is effective for public business entities for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. The Company has adopted this guidance prospectively and such adoption did not have an 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, which supersedes the revenue recognition requirements in Accounting Standards Codification Topic 605, “Revenue Recognition,” and most industry-specific guidance. 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. In 2015, the FASB delayed the effective date one year, beginning in fiscal year 2018.

The Company has substantially completed its scoping and assessment of impact of the new revenue recognition standard. The Company has evaluated a representative sample of revenue contracts related to its oil, natural gas and NGLs revenues. For these contracts, the Company has reviewed the contract provisions and evaluated the contracts under the new standard to assess the impact on the quantum and timing of revenue recognition and presentation of revenues on adoption of the new guidance. The Company believes that it has identified all material contract types and contractual features that represent the Company’s revenue. Based upon work completed to date, the Company does not currently expect that the adoption of this standard will have a material impact on net profit, although the Company does believe that certain reclassifications between revenue and expenses may be required based upon its assessment of i) where control passes to the customer and ii) whether the Company represents the principal or agent in certain arrangements. In addition, the Company’s disclosures surrounding revenue recognition will be more substantial upon adoption. These conclusions are subject to change and the Company is continuing to evaluate the requirements of this standard as it works towards finalizing its assessment, and as it continues to perform other implementation activities such as establishing new policies, procedures and controls, quantifying the adoption date adjustments and drafting disclosures. The Company is required to apply this new standard beginning January 1, 2018. Two methods of transition are permitted under this standard: the full retrospective method, in which the standard would be applied retrospectively to each prior reporting period presented, subject to certain allowable exceptions; or the modified retrospective method, in which the standard would be applied to all contracts existing as of the date of initial application, with the cumulative effect of applying the standard recognized in retained earnings (the adoption date adjustments). The Company anticipates adopting this standard using the modified retrospective method.

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., specifically the states of Oklahoma, Pennsylvania and West Virginia. On April 8, 2016, the Company sold substantially all of its producing assets and proved reserves and a significant portion of its undeveloped acreage in Pennsylvania and West Virginia comprising the Company's assets in the Appalachian Basin. On January 20, 2017, the Compan y sold its remaining interest in producing wells and undeveloped acreage in West Virginia, effective January 1, 2017, for $200,000 before fees and expenses.

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

	September 30, 2017	December 31, 2016
	(in thousands)	
Unproved properties, excluded from amortization:		
Drilling in progress costs	$ 10,881	$ 1,100
Acreage acquisition costs	113,110	58,857
Capitalized interest	11,954	7,376
Total unproved properties excluded from amortization	$ 135,945	$ 67,333

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 each reporting 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:

	2017			
	Total Year to Date Impairment	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu) (1)		$ 3.00	$ 3.01	$ 2.73
WTI oil price (per Bbl) (1)		$ 49.81	$ 48.95	$ 47.61
Impairment recorded (pre-tax) (in thousands)	$ —	$ —	$ —	$ —

	2016			
	Total Year to Date Impairment	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu) (1)		$ 2.28	$ 2.24	$ 2.40
WTI oil price (per Bbl) (1)		$ 41.68	$ 43.12	$ 46.26
Impairment recorded (pre-tax) (in thousands)	$ 48,497	$ —	$ —	$ 48,497

(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 WTI spot oil prices.

The Company could potentially incur ceiling test impairments in the future should commodities prices decline. However, it is difficult to project future impairment charges in light of numerous variables involved.

The Company's proved reserves estimates and their estimated discounted value and standardized measure will also be impacted by changes in lease operating costs, future development costs, production, exploration and development activities and estimated future income taxes. The ceiling limitation calculation is not intended to be indicative of the fair market value of the Company's proved reserves or future results.

STACK Leasehold Acquisition

On March 22, 2017, the Company completed the acquisition of additional working and net revenue interests in approximately 66 gross (9.5 net) producing wells and 5,670 net acres of additional undeveloped STACK Play leasehold in Kingfisher County, Oklahoma, effective March 1, 2017, for $51.4 million (the “STACK Leasehold Acquisition”). Prior to the completion of the STACK Leasehold Acquisition, the Company held an interest in the majority of acquired producing wells and acreage. The Company accounted for th e STACK Leasehold Acquisition as an asset acquisition.

Development Agreement

On October 14, 2016, the Company executed an agreement with STACK Exploration LLC (the “Investor”) (the “Development Agreement”) to jointly develop up to 60 Gastar operated wells in the STACK Play in Kingfisher County, Oklahoma (the “Drilling Program”). The Drilling Program targeted the Meramec and Osage formations within the Mississippi Lime in a contract area within three townships covering approximately 32,900 gross (21,200 net) undeveloped mineral acres under leases held by the Company. The Company is the operator of all wells jointly developed under the Development Agreement.

Under the Development Agreement, the Investor funded 90% of the Company’s working interest portion of drilling and completion costs to initially earn 80% of the Company’s working interest in each new well (in each case, proportionately reduced by other participating working interests in the well). As a result, the Company paid 10% of its working interest portion of such costs for 20% of its original working interest.

The proposed Drilling Program wells were to be mutually developed in three tranches of 20 wells each. The locations of the first 20 wells, comprised of 18 Meramec formation wells and two Osage formation wells, were mutually agreed upon by the Company and the Investor. Participation in the second tranche of 20 Drilling Program wells was to be at the election of the Investor and the third tranche of 20 wells would require mutual consent. On July 31, 2017, the Investor elected not to participate in the second tranche of wells. With respect to each 20-well tranche, when the Investor has achieved an aggregate 15% internal rate of return for its investment in the tranche, Investor’s interest will be reduced from 80% to 40% of the Company’s original working interest and the Company’s working interest increases from 20% to 60% of its original working interest. When a tranche internal rate of return of 20% is achieved by the Investor, Investor’s working interest decreases to 10% and the Company’s working interest increases to 90% of the working interest originally owned by the Company.

Upon completion of a tranche, the Investor has the right, but not the obligation, for a period of six months to cause the Company to purchase the Investor’s interest in the Drilling Program that is not subject to final reversion (the “WI Tail”) for such tranche (the “Investor Put Right”) for fair market value by applying the methodology to determine a 15% discounted present value as defined by the Development Agreement. If the Investor fails to exercise the Investor Put Right within the six-month period after achieving final reversion, then for a period of six months thereafter, the Company shall have the right, but not the obligation, to purchase the WI Tail from the Investor on the same fair market value approach of the Investor Put Right. If final reversion has not been achieved by the eighth anniversary of the spud date of the first well in a given tranche, Investor will, for a period of six months thereafter, have the right to cause us to buy Investor’s then-current interest in such tranche at an agreed upon valuation. Based on current commodity prices, well cost and production performance of the completed wells in the first tranche, the 15% of internal rate of return is not anticipated to be achieved.

As of September 30, 2017, the Company and the Investor had completed 20 gross (15.8 net; 3.2 net to the Company) wells, all of which were on production, within the first tranche of the Drilling Program.

Canadian County Property Sale

On October 19, 2016, the Company entered into a purchase and sale agreement (the “Red Bluff PSA”) to sell certain non-core leasehold interests in approximately 25,300 net acres of which only 19,100 net acres was ascribed allocated value and interests in 25 gross (11.2 net) wells primarily in northeast Canadian County and also in southeast Kingfisher County, Oklahoma to Red Bluff Resources Operating, LLC (“Red Bluff”) for $71.0 million (of which up to $10.0 million was contingent upon the satisfaction of certain conditions), subject to certain adjustments and with a property sale effective date of August 1, 2016 (“South STACK Play Acreage Sale”). As of September 30, 2017, the sale was completed and the Company had received approximately $69.5 million of sales proceeds from the South STACK Play Acreage Sale. The sale was reflected as a reduction to the full cost pool and no adjustment to the income statement was necessary as it was determined not to be significant.

Appalachian Basin Sale

On February 19, 2016, the Company entered into an agreement to sell substantially all of its producing assets and proved reserves and a significant portion of its undeveloped acreage in the Appalachian Basin for $80.0 million, subject to customary closing adjustments (the “Appalachian Basin Sale”). Pursuant to the agreement, on April 8, 2016, the Company completed the Appalachian Basin Sale for an adjusted sales price of $75.7 million, net of $3.5 million of suspense liability transferred to buyer. The Appalachian Basin Sale was reflected as a reduction to the full cost pool and the Company did not record a gain or loss related to the divestiture as it was not d etermined to be significant to the full cost pool and did not result in a significant change to the depletion rate.

4. Long-Term Debt

The table below provides a reconciliation of the Company's long-term debt balance as presented in the condensed consolidated balance sheets for the periods presented:

	September 30, 2017		December 31, 2016	
	(in thousands)			
Term Loan, principal balance (1)	$	250,000	$	—
Less:				
Unamortized deferred financing costs (2)		(4,909)		—
Unamortized debt discount (2)		(22,958)		—
Term Loan, net	$	222,133	$	—
Notes, principal balance	$	162,500	$	—
Less:				
Unamortized deferred financing costs (2)		(2,765)		—
Unamortized debt discount (2)		(48,275)		—
Notes, net	$	111,460	$	—
Revolving credit facility	$	—	$	84,630
Former senior secured notes	$	—	$	325,000
Less:				
Unamortized deferred financing costs		—		(795)
Unamortized debt discount				(4,342)
Former senior secured notes, net	$	—	$	319,863
Total long-term debt	$	333,593	$	404,493

(1) Pursuant to Amendment No. 2 (as defined below), on October 2, 2017, the Company elected to pay in kind 100% of the interest due for the period June 30, 2017 to October 1, 2017 in the amount of $6.6 million, thus increasing the outstanding principal balance of the Term Loan (as defined below) to $256.6 million at such time.

(2) The unamortized deferred financing costs and debt discount will be amortized over the remaining life of the Term Loan and Notes (as defined below), respectively, based on the effective interest method.

Ares Investment Transactions

On March 3, 2017, certain funds (the "Purchasers") managed indirectly by Ares Management LLC ("Ares") purchased from the Company for cash (i) $125.0 million aggregate principal amount of its Convertible Notes due 2022 ("Notes") sold at par, which Notes, subject to the receipt of approval of the Company's stockholders which was obtained on May 2, 2017, are convertible into common stock, par value $0.001 per share of the Company (the "Common Stock") or, in certain circumstances, cash in lieu of Common Stock or a combination of cash and shares of Common Stock as described below and (ii) 29,408,305 shares of Common Stock for a purchase price of $50.0 million. In addition, an affiliate of Ares concurrently loaned the Company $250.0 million pursuant to the Third Amended and Restated Credit Agreement among the Company (the "Term Loan"), as borrower, the guarantors party thereto, AF V Energy I Holdings, L.P., a fund managed indirectly by Ares, as lender, and Wilmington Trust, National Association, as Administrative Agent as further described below. The proceeds from the sale of the Notes, the Common Stock and the Term Loan were used to fully repay and redeem the Company's prior Revolving Credit Facility (as defined below) and to satisfy and discharge its $325.0 million of 8.625% senior secured notes due May 2018, which were satisfied and discharged on March 3, 2017 by irrevocably calling for redemption and depositing with the indenture trustee cash in the amount of the redemption price of 102.156% of their principal amount plus accrued and unpaid interest to the redemption date of March 24, 2017, and to pay the expenses from the Ares transactions.

In order to provide funding for the STACK Leasehold Acquisition and a portion of the Company's 2017 capital budget, on March 21, 2017, the Purchasers purchased from the Company for cash an additional $75.0 million aggregate principal amount of its Notes sold at par (t he "Additional Notes").

The Notes, including the Additional Notes, were issued with conversion rights that were subject to the approval of holders of issued and outstanding Common Stock (other than the Purchasers), which approval was obtained May 2, 2017 (the "Requisite Stockholder Approval"). Pursuant to the purchase agreement for the Additional Notes, upon receipt of Requisite Stockholder Approval, Purchasers and the Company exchanged $37.5 million principal amount of the Additional Notes for (a) 25,456,521 newly issued shares of Common Stock (the "Repurchase Shares") and (b) 2,000 shares of the Company's Special Voting Preferred Stock, par value $0.01 per share (the "Mandatory Repurchase"). The terms of Mandatory Repurchase, which was effected May 5, 2017, provided for one Repurchase Share issued for each $1.4731 of outstanding principal of the repurchased Notes, which was based on the 10-day volume weighted average trading price ("VWAP") of the Common Stock for the period ended March 17, 2017. The exchange reduced the aggregate principal amount of issued and outstanding Notes from $200.0 million to $162.5 million at June 30, 2017, which principal amount remains outstanding at September 30, 2017.

Term Loan

On March 3, 2017, the Company entered into a credit agreement for the Term Loan. The Term Loan bears interest at a per annum rate equal to 8.5%, payable on a quarterly basis on each March 31, June 30, September 30 and December 31 of each year, commencing March 31, 2017. The Term Loan has a scheduled maturity of March 3, 2022. In addition, the Term Loan is subject to an interest "make-whole" and repayment premium, such that any repayment or prepayment of the loans thereunder prior to the stated maturity date shall be subject to the payment of a repayment premium, and depending on the date of such repayment or prepayment, the applicable interest "make-whole" amount, with the amount of such repayment premium decreasing over the life of the Term Loan.

The Term Loan is guaranteed by the Company's sole domestic subsidiary and will be guaranteed by all of the Company's future domestic subsidiaries formed during the term of the Term Loan. The Term Loan is secured by a first-priority lien on substantially all of the assets of the Company and its subsidiaries, excluding certain assets as customary exceptions.

The Term Loan contains various customary covenants for credit facilities of this type, including, among others, restrictions on granting liens, incurrence of other indebtedness, payments of certain dividends and other restricted payments, engaging in transactions with affiliates, dispositions of assets and other, in each case subject to certain baskets and exceptions, and at September 30, 2017, the Company was in compliance with such covenants.

All outstanding amounts owed become due and payable upon the occurrence of certain usual and customary events of default, including among others (i) failure to make payments; (ii) non-performance of covenants and obligations continuing beyond any applicable grace period; and (iii) the occurrence of a change in control of the Company, as defined in the Term Loan.

The Company accounted for the Term Loan in accordance with guidance relating to " *Debt with Conversion and Other Options* " which indicates that when multiple securities are issued in a single transaction, total proceeds should be allocated based on the relative fair values of each instrument, assuming no instrument is subsequently required to be recorded at fair value. The fair value of the Term Loan at the date of issuance was determined to be at a discounted $224.8 million based on the fair value of similar debt instruments. The $25.2 million debt discount related to the Term Loan and the $5.5 million on issuance costs associated with the Term Loan will be amortized over the life of the Term Loan using the effective interest method. The effective interest rate for the Term Loan is approximately 13%.

On March 20, 2017, the Company, together with the parties thereto, entered into an Amendment No. 1 to the Term Loan which amendment permitted the issuance of the Additional Notes.

On August 2, 2017, the Company, together with the parties thereto, entered into an Amendment No. 2 to Term Loan ("Amendment No. 2"). Amendment No. 2 amended the Term Loan, to among other things, (i) allow for the payment of pay in kind ("PIK") interest on the Term Loan at the applicable PIK percentage and (ii) increased the applicable rate for periods ending after June 30, 2017 from 8.5% per annum to 10.25% per annum. Amendment No. 2 allows the Company to elect to PIK upon proper notice 100% of interest payments due after June 30, 2017 and prior to December 31, 2018 and at the Company's election, PIK between 0% and 50% of any interest payments occurring after December 31, 2018 (other than interest due on the maturity date or the date of any repayment or prepayment). The Term Loan interest rate increased to 10.25% for all interest periods post June 30, 2017 and the PIK interest shall be payable by capitalizing and adding such amounts to the outstanding principal amount of the Term Loan on the applicable interest payment date.

On September 18, 2017, the Company, together with the parties thereto, entered into an Amendment No. 3 to the Term Loan ("Amendment No. 3"). Amendment No. 3 amended t he Term Loan to, among other things, expressly provide that certain assignments of oil and natural gas properties made or to be made by the Company to Red Bluff, pursuant to the Red Bluff PSA, are permitted by the Term Loan and are not subject to the manda tory prepayment provisions applicable to "Asset Sales" under the Term Loan.

A carrying amount of the Term Loan for the period indicated is as follows:

		September 30, 2017
		(in thousands)
Term Loan, principal balance (1)	$	250,000
Less:		
Unamortized deferred financing costs (2)		(4,909)
Unamortized debt discount (2)		(22,958)
Term loan, net	$	222,133

(1) Pursuant to Amendment No. 2, on October 2, 2017, the Company elected to pay in kind 100% of the interest due for the period June 30, 2017 to October 1, 2017 in the amount of $6.6 million, thus increasing the outstanding principal balance of the Term Loan to $256.6 million at such time.

(2) The unamortized deferred financing costs and debt discount will be amortized over the remaining life of the Term Loan based on the effective interest method.

Indenture and Notes

On March 3, 2017, the Company entered into an indenture (the "Indenture") by and among the Company, the subsidiary guarantor named therein, and Wilmington Trust, National Association, as trustee (the "Trustee") and collateral trustee, with respect to the Notes. The principal terms of the Notes are governed by the Indenture. Pursuant to the Indenture, the Notes were issued for cash at par, bear interest at 6.0% per annum and will mature on March 1, 2022, unless earlier repurchased, redeemed or converted in accordance with the terms of the Indenture. Interest is payable on the Notes on each March 1, June 1, September 1 and December 1 of each year, commencing on June 1, 2017.

Pursuant to the Indenture, Requisite Stockholder Approval was required on or before July 3, 2017 to approve the conversion rights of the Notes (including the Additional Notes) to be convertible at the option of the holder into shares of Common Stock based on the terms of the Indenture. Requisite Stockholder Approval was obtained on May 2, 2017 at a special meeting of stockholders.

The interest rate on the Notes was subject to an increase in certain circumstances if the Company fails to comply with certain obligations under a Registration Rights Agreement described in "Note 7 – Capital Stock" below, and on the Notes in the case of certain issuances of Common Stock by the Company at a price below $1.7002 per share (subject to adjustment).

The Notes are secured by a second-priority lien on substantially all of the assets of the Company. If at least a majority of the Notes issued pursuant to the Securities Purchase Agreement dated February 16, 2017 (the "Purchase Agreement") cease to be held by affiliates of Ares as provided in the Indenture, the liens securing the Notes will be released and substantially all of the restrictive covenants in the Indenture will terminate.

The Indenture restricts the ability of the Company and certain of its subsidiaries to, among other things: (i) pay dividends or make other distributions in respect of the Company's capital stock or make other restricted payments; (ii) incur additional indebtedness and issue preferred stock; (iii) make certain dispositions and transfers of assets; (iv) engage in transactions with affiliates; (v) create liens; (vi) engage in certain business activities that are not related to oil and gas; and (vii) impair any security interest. These covenants are subject to a number of exceptions and qualifications.

The Indenture provides that a number of events will constitute an Event of Default (as defined in the Indenture), including, among other things: (i) a failure to pay the Notes when due at maturity, upon redemption or repurchase; (ii) failure to pay interest for 30 days; (iii) the Company's failure to deliver certain notices; (iv) a default in the Company's obligation to convert the Notes; (v) the Company's failure to comply with certain covenants relating to merger, consolidation or sale of assets; (vi) the Company's failure to comply, for 60 days following notice, with any of the other covenants or agreements in the Indenture; (vii) a default, which is not cured within 30 days, by the Company or any Restricted Subsidiaries (as defined in the Indenture) with respect to any mortgages or any indebtedness for money borrowed of at least $15 million; (viii) one or more final judgments against the Company or any of its Restricted Subsidiaries for the payment of at least $15 million; (ix) the Company's failure to make any payments required under that certain development agreement; (x) causing any Guarantee (as defined in the Indenture) to cease to be in full force and effect; (xi) the cessation to be in full force and effect of any of the collateral agreements entered into with respect to the Notes; and (xii) certain events of bankruptcy or in solvency. In the case of an Event of Default arising from certain events of bankruptcy or insolvency with respect to the Company, all outstanding Notes will become due and payable immediately without further action or notice. If any other Event of Default occurs and is continuing, the Trustee or the holders of at least 25% in aggregate principal amount of the then outstanding Notes may declare all the Notes to be due and payable immediately. At September 30, 2017, no Event of Default had occurred.

In accordance with accounting guidance relating to " *Debt with Conversion and Other Options"* which indicates that when multiple securities are issued in a single transaction, total proceeds should be allocated based on the relative fair values of each instrument, assuming no instrument is subsequently required to be recorded at fair value. The Company accounted for the Notes based on their relative fair value to the bundled transaction and subsequently separately accounted for the liability and equity conversion components of the Notes due to the Company's option to settle the conversion obligation in cash. The fair value of the debt portion of the Notes, excluding the conversion feature, at the dates of issuance was estimated to be approximately $147.8 million and was calculated based on the fair value of similar non-convertible debt instruments in conjunction with the relative fair value of the Term Loan issued on the same date. As a result of such valuation, a debt discount of $52.4 million related to the Notes was recorded. Additionally, the value of the conversion option at the dates of issuance was calculated to be $77.6 million based on the residual fair value after application of such to the debt and was recorded as additional paid-in capital on the Company's condensed consolidated balance sheet. Total debt issuance costs related to the Notes were $5.4 million, of which $3.2 million was allocated to the liability component of the Notes and $2.2 million to the equity component of the Notes. The debt discount and the liability component of the debt issuance costs will be amortized over the term of the Notes. The weighted average effective interest rate used to amortize the debt discount and the liability component of the debt issue costs for the Notes is approximately 15% based on the Company's estimated non-convertible borrowing rate as of the date the Notes were initially issued. Since the Company incurred losses for all periods, the impact of the conversion option would be anti-dilutive to the earnings per share and therefore was not included in the calculation.

The carrying amount of the liability component of the Notes for the period indicated is as follows:

		September 30, 2017
		(in thousands)
Notes, principal balance	$	162,500
Less:		
Unamortized deferred financing costs (1)		(2,765)
Unamortized debt discount (1)		(48,275)
Notes, net	$	111,460

(1) The unamortized deferred financing costs and debt discount will be amortized over the remaining life of the Notes based on the effective interest method.

The carrying amount of the equity components of the Notes recorded in additional paid in capital for the period indicated is as follows:

		September 30, 2017
		(in thousands)
Value of conversion option	$	77,626
Debt issuance costs attributable to conversion option	$	(2,164)
Total	$	75,462

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"). The Revolving Credit Facility had a scheduled maturity of November 14, 2017.

On January 10, 2017, the Company, together with the parties thereto, entered into an amendment to the Revolving Credit Facility ("Amendment No. 10"), which amended the Revolving Credit Facility to, among other things, permit the payment of certain cash dividends on its preferred stock, including the dividends declared payable on January 31, 2017, provided that (i) the Company's borrowing base was correspondingly reduced in the amount of any such dividend payment and (ii) the Company paid down its outstanding indebtedness under the Revolving Credit Facility in the amount of any resulting borrowing base deficiency.

Under Amendment No. 10, payme nt of the declared January 2017 dividend and monthly preferred stock cash dividends through May 2017 was permitted contingent upon the satisfaction of certain conditions, including but not limited to, (i) the absence of any defaults or borrowing base defic iency, (ii) for any dividends declared and paid in respect of April 2017 and May 2017, having cash liquidity (including any available borrowings under the Revolving Credit Facility) of more than $30.0 million and (iii) paying any permitted dividends solely from proceeds received by the Company from sales of equity since November 30, 2016 (including through the Company's at-the-market issuance sales agreement with a third-party sales agent to sell, from time to time, shares of the Company's common stock (the "ATM Program"). Under Amendment No. 10, the Company also agreed to pay down indebtedness under its Revolving Credit Facility by at least an additional $8.1 million by April 30, 2017.

On March 3, 2017, the Company used a portion of the net proceeds from the transactions described in this Note 4 under the caption "Ares Investment Transactions" to fully repay all of the $69.2 million borrowings outstanding under the Revolving Credit Facility (which was terminated on such date).

Senior Secured Notes

At December 31, 2016, the Company had $325.0 million aggregate principal amount of 8 5/8% Senior Secured Notes due May 15, 2018 (the "Former Notes") outstanding under an 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. The Notes bore interest at a rate of 8.625% per year, payable semi-annually in arrears on May 15 and November 15 of each year. Effective May 17, 2016, Wells Fargo Bank, National Association resigned as Trustee and Collateral Agent and Wilmington Trust was appointed Trustee and Collateral Agent pursuant to the Indenture.

On March 3, 2017, the redemption price plus interest on all of the Company's outstanding $325.0 million principal of the Former Notes was funded to satisfy and discharge the Former Notes from a portion of the net proceeds from the transactions described in this Note 4 under the caption "Ares Investment Transactions." All of the Former Notes were satisfied and discharged on March 3, 2017 by irrevocably calling for redemption and depositing with the indenture trustee cash in the amount of the redemption price of 102.156% of the principal amount, or principal plus an additional $7.0 million, plus accrued and unpaid interest to the redemption date of March 24, 2017. Additionally, the Company wrote-off $5.2 million of remaining unamortized deferred financing costs related to the Former Notes upon redemption.

5. Fair Value Measurements

Certain of 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 (as defined below) inputs. Should an impairment of unproved properties occur, the value of the impaired properties would be reclassified into proved properties in the full cost pool subject to depletion. As no other fair value measurements are required to be recognized on a non-recurring basis at September 30, 2017, no additional disclosures are provided at September 30, 2017.

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:

- 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 vari ous 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 woul d 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 2017 and 2016 periods.

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 September 30, 2017 and December 31, 2016:

	Fair value as of September 30, 2017			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets:				
Cash and cash equivalents	$ 29,229	$ —	$ —	$ 29,229
Commodity derivative contracts	—	—	4,816	4,816
Liabilities:				
Commodity derivative contracts	—	—	(455)	(455)
Total	$ 29,229	$ —	$ 4,361	$ 33,590

	Fair value as of December 31, 2016			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets:				
Cash and cash equivalents	$ 71,529	$ —	$ —	$ 71,529
Commodity derivative contracts	—	—	7,850	7,850
Liabilities:				
Commodity derivative contracts	—	—	(338)	(338)
Total	$ 71,529	$ —	$ 7,512	$ 79,041

The table below presents a reconciliation of the assets and liabilities classified as Level 3 in the fair value hierarchy for the three and nine months ended S eptember 30, 2017 and 2016. 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 September 30, 2017 and 2016.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)			
Balance at beginning of period	$ 9,436	$ 12,782	$ 7,512	$ 24,418
Total (losses) gains included in earnings	(2,896)	(1,498)	3,782	(3,991)
Purchases	—	—	470	565
Issuances	—	—	—	(165)
Settlements (1)	(2,179)	(2,231)	(7,403)	(11,774)
Balance at end of period	$ 4,361	$ 9,053	$ 4,361	$ 9,053
The amount of total (losses) gains for the period included in earnings attributable to the change in mark to market of commodity derivatives contracts still held at September 30, 2017 and 2016	$ (4,672)	$ (3,134)	$ (1,898)	$ (12,974)

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

At September 30, 2017, the estimated fair value of accounts receivable, accounts and revenue payables approximates their carrying value due to their short-term nature. The estimated fair value of the Notes excluding the conversion feature at September 30, 2017 was $132.7 million calculated based on the fair value of similar non-convertible debt instruments (Level 2) since an observable quoted price of the Notes or a similar asset or liability is not readily available. The estimated fair value of the Term Loan at September 30, 2017 was $214.9 million calculated based on the fair value of similar debt instruments (Level 2) since an observable price of the Term Loan or a similar asset or liability is not readily available.

The Company has consistently applied the valuation techniques discussed above in all periods presented.

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 September 30, 2017 and 2016, the Company reported losses of $4.7 million and $3.1 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 September 30, 2017 and 2016. For the nine months ended September 30, 2017 and 2016, the Company reported losses of $1.9 million and $13.0 million, respectively, in the consolidated statements of operations related to the change in the fair value of its commodity derivative contracts still held at September 30, 2017 and 2016.

As of September 30, 2017, 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)	Total of Notional Volume	Base Fixed Price	Floor (Long)	Short Put	Ceiling (Short)
		(in Bbls)					
October to December 2017	Costless three-way collar	280	25,760	$ —	$ 80.00	$ 65.00	$ 97.25
October 2017	Costless three-way collar	200	6,200	$ —	$ 80.00	$ 60.00	$ 98.70
November 2017	Costless three-way collar	250	7,500	$ —	$ 80.00	$ 60.00	$ 98.70
December 2017	Costless three-way collar	200	6,200	$ —	$ 80.00	$ 60.00	$ 98.70
October to December 2017	Put spread	500	46,000	$ —	$ 82.00	$ 62.00	$ —
October to December 2017	Fixed price swap	400	36,800	$ 54.50	$ —	$ —	$ —
October to December 2017	Fixed price swap	150	13,800	$ 53.80	$ —	$ —	$ —
October to December 2017	Fixed price swap	150	13,800	$ 50.25	$ —	$ —	$ —
October to December 2017	Fixed price swap	500	46,000	$ 50.00	$ —	$ —	$ —
October to December 2017	Fixed price swap	500	46,000	$ 50.00	$ —	$ —	$ —
October to December 2017	Fixed price swap	100	9,200	$ 50.60	$ —	$ —	$ —
October to December 2017	Fixed price swap	100	9,200	$ 50.94	$ —	$ —	$ —
October to December 2017	Fixed price swap	100	9,200	$ 50.50	$ —	$ —	$ —
October to December 2017	Fixed price swap	100	9,200	$ 50.65	$ —	$ —	$ —
October to December 2017	Fixed price swap	100	9,200	$ 50.35	$ —	$ —	$ —
December 2017	Fixed price swap	350	10,850	$ 52.33	$ —	$ —	$ —
October to December 2017	Costless collar	200	18,400	$ —	$ 45.00	$ —	$ 53.50
January to December 2018	Costless three-way collar	500	182,500	$ —	$ 50.00	$ 40.00	$ 61.60
January to March 2018	Costless three-way collar	1,800	162,000	$ —	$ 47.50	$ 37.50	$ 57.85
April to June 2018	Costless three-way collar	1,700	154,700	$ —	$ 47.50	$ 37.50	$ 57.85
July to September 2018	Costless three-way collar	1,600	147,200	$ —	$ 47.50	$ 37.50	$ 57.85
October to December 2018	Costless three-way collar	1,700	156,400	$ —	$ 47.50	$ 37.50	$ 57.85
January to August 2018	Put spread	425	103,275	$ —	$ 80.00	$ 60.00	$ —
January to June 2018	Fixed price swap	600	108,600	$ 51.20	$ —	$ —	$ —
January to June 2018	Fixed price swap	200	182,500	$ 50.11	$ —	$ —	$ —
July to September 2018	Fixed price swap	500	46,000	$ 51.20	$ —	$ —	$ —
October to December 2018	Fixed price swap	600	55,200	$ 51.20	$ —	$ —	$ —
January to September 2019	Costless three-way collar	2,000	546,000	$ —	$ 47.50	$ 37.50	$ 59.70
October to December 2019	Costless three-way collar	1,900	174,800	$ —	$ 47.50	$ 37.50	$ 59.70
January to September 2019	Fixed price swap	700	191,100	$ 50.40	$ —	$ —	$ —
October to December 2019	Fixed price swap	600	55,200	$ 50.40	$ —	$ —	$ —

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

As of September 30, 2017, the following natural gas derivative transactions were outstanding with the associated notional volumes and weighted average underlying hedge prices:

Settlement Period	Derivative Instrument	Average Daily Volume	Total of Notional Volume	Base Fixed Price	Floor (Long)	Short Put	Ceiling (Short)
		(in MMBtus)					
November to December 2017	Costless three-way collar	5,000	305,000	$ —	$ 3.00	$ 2.35	$ 4.00
November to December 2017	Fixed price swap	2,600	158,600	$ 3.40	$ —	$ —	$ —
November to December 2017	Costless Collar	2,600	158,600	$ —	$ 3.00	$ —	$ 3.89
January to December 2018	Costless three-way collar	5,000	1,825,000	$ —	$ 3.00	$ 2.35	$ 4.00
January to March 2018	Costless Collar	5,800	522,000	$ —	$ 3.00	$ —	$ 4.28

As of September 30, 2017, all of the Company's economic derivative hedge positions were with large 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 c ertain put premiums for the production month period October 2017 through December 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 lia bilities as they become payable. The following table provides information regarding the deferred put premium liabilities for the periods indicated:

	September 30, 2017	December 31, 2016
	(in thousands)	
Current commodity derivative put premium payable	$ 1,337	$ 1,654
Long-term commodity derivative put premium payable	34	969
Total unamortized put premium liabilities	$ 1,371	$ 2,623

	For the Three Months Ended September 30, 2017	For the Nine Months Ended September 30, 2017
	(in thousands)	
Put premium liabilities, beginning balance	$ 1,773	$ 2,623
Settlement of put premium liabilities	(402)	(1,722)
Additional put premium liabilities	—	470
Put premium liabilities, ending balance	$ 1,371	$ 1,371

The following table provides information regarding the amortization of the deferred put premium liabilities by year as of September 30, 2017:

	Amortization
	(in thousands)
October to December 2017	$ 402
January to December 2018	969
Total unamortized put premium liabilities	$ 1,371

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)		
		Fair Value	
	Balance Sheet Location	September 30, 2017	December 31, 2016
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Current assets	$ 4,400	$ 6,212
Commodity derivative contracts	Other assets	416	1,638
Commodity derivative contracts	Current liabilities	(326)	(338)
Commodity derivative contracts	Long-term liabilities	(129)	—
Total derivatives not designated as hedging instruments		$ 4,361	$ 7,512

	Location of Loss Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives For the Three Months Ended September 30, 2017	2016
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Loss on commodity derivatives contracts	$ (2,896)	$ (1,498)
Total		$ (2,896)	$ (1,498)

	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives For the Nine Months Ended September 30, 2017	2016
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Gain (loss) on commodity derivatives contracts	$ 3,782	$ (3,991)
Total		$ 3,782	$ (3,991)

7. Capital Stock

Common Stock

On May 7, 2015, the Company entered into the ATM Program 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 shares were issued pursuant to the Company's then-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 year ended December 31, 2016, 18,606,943 shares were sold through the ATM Program for net proceeds of $24.4 million. For the period January 1, 2017 to February 20, 2017, the Company sold 5,447,919 shares through the ATM Program for net proceeds of $8.3 million. The ATM Program expired February 24, 2017.

On March 3, 2017, the Purchasers affiliated with Ares purchased for cash (i) $125.0 million aggregate principal amount of Notes sold at par and (ii) 29,408,305 shares of Common Stock for a purchase price of $50.0 million. The Common Stock sale was priced based on a 30-trading day VWAP of $1.7002 determined on February 15, 2017 the date immediately prior to the signing date of the Purchase Agreement with Purchasers in respect to such sale.

On March 21, 2017, the Company sold to Purchasers affiliated with Ares an additional $75.0 million aggregate principal amount of Notes. Pursuant to the purchase agreement for the Additional Notes, after obtaining the Requisite Stockholder Approval, on May 5, 2017, the Company and the Purchasers exchanged $37.5 million aggregate principal amount of the outstanding Additional Notes for the issuance to Purchasers of the Mandatory Repurchase.

The Notes are convertible into shares of Common Stock as described in more detail in Note 4.

On June 27, 2017, the Company's stockholders approved an amendment to the Company's certificate of incorporation to increase the number of authorized shares of common stock from 550,000,000 to 800,000,000, which amendment became effective on July 24, 2017.

Stockholder Rights Agreements

On January 18, 2016, the Company's board of directors adopted the Rights Agreement dated as of January 18, 2016, between the Company and American Stock Transfer & Trust Company, LLC (the "2016 Rights Agreement") pursuant to which the Company declared a dividend of one right (a "2016 Right") for each of the Company's issued and outstanding shares of common stock. The dividend was paid to stockholders of record on January 28, 2016. Each 2016 Right entitled the holder, subject to the terms of the 2016 Rights Agreement, to purchase one one-thousandth of a share of the Company's Series C Junior Participating Preferred Stock (the "Series C Preferred Stock") at a price of $6.96, subject to certain adjustments. The purpose of the 2016 Rights Agreement was to diminish the risk that the Company 's ability to reduce potential future federal income tax obligations would become subject to limitations by reason of an "ownership change," as defined in Section 382 of the Internal Revenue Code of 1986, as amended (the "Internal Revenue Code"). The 2016 Rights and the 2016 Rights Agreement expired on January 18, 2017.

On January 27, 2017, the Company's board of directors adopted the Rights Agreement dated as of January 27, 2017, between the Company and American Stock Transfer & Trust Company, LLC (the "2017 Rights Agreement") pursuant to which the Company declared a dividend of one right (a "Right") for each of the Company's issued and outstanding shares of common stock. The dividend was paid to stockholders of record on February 10, 2017. Each Right entitled the holder, subject to the terms of the 2017 Rights Agreement, to purchase one one-thousandth of a share of Series C Preferred Stock at a price of $10.74, subject to certain adjustments. The purpose of the 2017 Rights Agreement was to diminish the risk that the Company's ability to reduce potential future federal income tax obligations would become subject to limitations by reason of an "ownership change," as defined in Section 382 of the Internal Revenue Code. On April 6, 2017, the Company amended the 2017 Rights Agreement to accelerate the expiration of the Rights to 5:00 P.M., New York City time on April 6, 2017, which had the effect of terminating the Rights and the 2017 Rights Agreement on that date.

In connection with entering into the recent equity and convertible debt transactions with funds managed indirectly by Ares , the Company determined that the value of the U.S. federal income tax benefits in the form of net operating losses have substantially been diminished by reason of an "ownership change," as defined under Section 382 of the Internal Revenue Code, in 2017. As a result, the Company decided to terminate the Rights.

Preferred Stock

Pursuant to the Company's certificate of incorporation, the Company has 40,000,000 shares of preferred stock authorized with a par value of $0.01 per share. The Company has designated 10,000,000 of such shares to constitute its 8.625% Series A Cumulative Preferred Stock (the "Series A Preferred Stock") and 10,000,000 of such shares to constitute its 10.75% Series B Cumulative Preferred Stock (the "Series B Preferred Stock"). The Series A Preferred Stock and the Series B Preferred Stock each have a liquidation preference of $25.00 per share. The Company has designated 550,000 of such shares as Series C Junior Participating Preferred Stock. On March 22, 2017, the Company designated 2,000 shares of such shares as Special Voting Preferred Stock with a liquidation preference of $0.01 for each such share, which is junior and subordinate to the right of the holders of any shares of any other existing or future series of preferred stock.

Series A Preferred Stock

At September 30, 2017, 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 extent of its stated liquidation preference and any accumulated and unpaid dividends) 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 whether declared or not.

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

The Company paid monthly dividends on the Series A Preferred Stock at a fixed rate of 8.625% per annum of the $25.00 per share liquidation preference through March 2016. Effective March 9, 2016, the Revolving Credit Facility prohibited the payment of cash dividends on the Company's preferred stock commencing April 2016. Pursuant to Amendment No. 10, on January 10, 2017, the Company declared a special cash dividend on the Series A Preferred Stock to pay in full all accumulated and unpaid cash dividends since April 1, 2016 at an annualized 8.625% through the payment date. The Series A Preferred Stock January 2017 dividend of $7.3 million was payable on January 31, 2017 to holders of record at the close of business on January 20, 2017. On August 1, 2017, primarily in response to the decline in oil prices and to preserve liquidity, the Company elected to suspend Series A Preferred Stock dividends commencing August 2017.

Dividends on the Series A Preferred Stock accumulate regardless of whether any such dividends are declared. If the Company fails to pay full cash dividends in four calendar quarters, whether consecutive or non-consecutive, then commencing in the calendar month following the first month in such fourth calendar quarter in which cash dividends are not paid in full, and until accumulated dividends are paid in full for four calendar quarters with the last two calendar quarters' dividends paid in cash, (i) the fixed dividend rate of Series A Preferred Stock each increases by 2.00% per annum, (ii) the Company may be required to issue a dividend of common stock to pay accrued and unpaid dividends, if such dividends are not paid in cash, provided it has sufficient surplus to pay such a dividend under state law, and (iii) the holders of Ser ies A Preferred Stock and Series B Preferred Stock, voting as a single class, will have the right to elect up to two additional directors to the board of directors of the Company. Under certain circumstances, "pay in kind" dividends of additional shares of Series A Preferred Stock may be payable in lieu of cash or common stock dividends.

For the three and nine months ended September 30, 2017, the Company recognized cash dividends of $727,000 and $5.1 million, respectively, and recognized undeclared cumulative dividends of $1.5 million for the three and nine months ended September 30, 2017, respectively, for the Series A Preferred Stock. For the three and nine months ended September 30, 2016, the Company recognized undeclared cumulative dividends of $2.2 million and $4.4 million, respectively, for the Series A Preferred Stock and for the nine months ended September 30, 2016, the Company recognized cash dividends on preferred stock of $2.2 million for the Series A Preferred Stock.

Series B Preferred Stock

At September 30, 2017, 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 extent of its stated liquidation preference and any accumulated and unpaid dividends) 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 paid monthly dividends on the Series B Preferred Stock at a fixed rate of 10.75% per annum of the $25.00 per share liquidation preference through March 2016. Effective March 9, 2016, the Revolving Credit Facility prohibited the payment of cash dividends on the Company's preferred stock commencing April 2016. Pursuant to Amendment No. 10, on January 10, 2017, the Company declared a special cash dividend on the Series B Preferred Stock to pay in full all accumulated and unpaid cash dividends since April 1, 2016 at an annualized 10.75% through the payment date. The Series B Preferred Stock January 2017 dividend in the amount of $4.8 million was payable on January 31, 2017 to holders of record at the close of business on January 20, 2017. On August 1, 2017, primarily in response to the decline in oil prices and to preserve liquidity, the Company elected to suspend Series B Preferred Stock dividends commencing August 2017.

Dividends on the Series B Preferred Stock will accumulate regardless of whether any such dividends are declared. If the Company fails to pay full cash dividends in four calendar quarters, whether consecutive or non-consecutive, then commencing in the calendar month following the first month in such fourth calendar quarter in which cash dividends are not paid in full, and until accumulated dividends are paid in full for four calendar quarters with the last two calendar quarters' dividends paid in cash, (i) the fixed dividend rate of Series B Preferred Stock each increases by 2.00% per annum, (ii) the Company may be required to issue a dividend of common stock to pay accrued and unpaid dividends, if such dividends are not paid in cash, provided it has sufficient surplus to pay such a dividend under state law, and (iii) the holders of Series A Preferred Stock and Series B Preferred Stock, voting as a single class, will have the right to elect up to two additional directors to the board of directors of the Company. Under certain circumstances, "pay in kind" dividends of additional shares of Series B Preferred Stock may be payable in lieu of cash or common stock dividends.

For the three and nine months ended September 30, 2017, the Company recognized cash dividends of $479,000 and $3.4 million, respectively, and recognized undeclared cumulative dividends of $959,000 for the three and nine months ended September 30, 2017, respectively, for the Series B Preferred Stock. For the three and nine months ended September 30, 2016, the Company recognized undeclared cumulative dividends of $1.4 million and $2.9 million, respectively, for the Series B Preferred Stock, and for the nine months ended September 30, 2016, the Company recognized cash dividends on prefe rred stock of $1.4 million for the Series B Preferred Stock.

Series C Preferred Stock

No shares of Series C Preferred Stock have been issued by the Company pursuant to the Stockholder Rights Agreements described above or otherwise.

Special Voting Preferred Stock

On May 4, 2017, the Company issued to Purchasers affiliated with Ares 2,000 shares of Special Voting Preferred Stock in connection with the exchange of $37.5 million principal of outstanding Notes described above in this Note 7 under the caption “Common Stock.”

The Special Voting Preferred Stock may be redeemed in whole any time after the initial holders beneficially own less than 5% of the Common Stock subject to the terms of its certificate of designation (the “Certificate of Designation”). There is no mandatory redemption of the Special Voting Preferred Stock. Holders of the Special Voting Preferred Stock are not entitled to receive any dividends declared and paid by the Company.

The Company’s Special Voting Preferred Stock have no voting rights, other than that the holders of the Special Voting Preferred Stock have the right to elect two members of the Company’s board of directors for so long as the initial holders, any specified subsequent holders (as defined in the Certificate of Designation) and their respective affiliates beneficially own at least 15% of the outstanding Common Stock in the aggregate, and the right to elect one member of the board of directors for so long as the initial holders, subsequent holders and their respective affiliates beneficially own at least 5% but less than 15% of the outstanding Common Stock in the aggregate. The Certificate of Designation contains certain restrictions on transfer of the Special Voting 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 September 30, 2017	**For the Nine Months Ended September 30, 2017**
Other share issuances:		
Shares of restricted common stock granted	5,000,000	8,649,345
Shares of restricted common stock vested	24,338	1,193,263
Shares of restricted common stock surrendered upon vesting/exercise (1)	871	356,450
Shares of restricted common stock forfeited	—	36,747

(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 27, 2017, the Company’s stockholders approved an amendment to the Gastar Exploration Inc. Long-Term Incentive Plan (the “LTIP”), effective May 2, 2017, to, among other things, increase the number of shares of common stock reserved for issuance under the LTIP by 14,000,000 shares of common stock. There were 6,565,088 shares of common stock available for issuance under the LTIP at September 30, 2017.

Due to a shortage in number of shares available under the LTIP at the time of the annual equity grant in January 2017, the Company granted 372,741 restricted stock units and 171,310 restricted stock units to its chief executive officer and chief financial officer, respectively. The restricted stock units were granted in place of restricted common stock and upon approval of stockholders of additional shares to the LTIP, the restricted stock units were converted to restricted common stock that will vest in three equal annual installments beginning on January 30, 2018. Additionally, the Company granted 372,741 performance based rights units and 171,310 performance based rights units to its chief executive officer and chief financial officer, respectively. The performance based rights units were issued in place of performance based units and upon approval of stockholders of additional shares to the LTIP, the performance based rights units were converted to performance based units that will vest in their entirety at the end of a three-year performance period with settlement in common stock between 0% and 200% of the target award based on the Company’s share price appreciation over a three-year performance period relative to a peer index. The performance based rights units have no voting rights.

Shares Reserved

At September 30, 2017, the Company had 164,400 common shares reserved for the exercise of stock options.

8. Interest Expense

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

	For the Three Months Ended September 30, 2017	For the Three Months Ended September 30, 2016	For the Nine Months Ended September 30, 2017	For the Nine Months Ended September 30, 2016
	(in thousands)			
Interest expense:				
Cash and accrued	$ 8,897	$ 8,158	$ 26,103	$ 25,275
Amortization of deferred financing costs and debt discount	3,291	986	8,218	3,812
Capitalized interest	(2,029)	(966)	(4,577)	(2,348)
Total interest expense	$ 10,159	$ 8,178	$ 29,744	$ 26,739

9. Income Taxes

For the three and nine months ended September 30, 2017 and 2016, 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. In connection with the Company’s recent equity and convertible debt transactions during 2017, the Company believes that the utilization of net operating losses in future years could be subjected to limitations by reason of an “ownership change” as defined under Section 382 of the Internal Revenue Code.

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 September 30, 2017	For the Three Months Ended September 30, 2016	For the Nine Months Ended September 30, 2017	For the Nine Months Ended September 30, 2016
	(in thousands, except per share and share data)			
Net loss attributable to common stockholders	$ (15,917)	$ (3,796)	$ (44,631)	$ (95,371)
Weighted average common shares outstanding - basic	209,072,232	129,301,817	190,745,688	104,125,317
Incremental shares from unvested restricted shares	—	—	—	—
Incremental shares from outstanding stock options	—	—	—	—
Incremental shares from outstanding PBUs	—	—	—	—
Weighted average common shares outstanding - diluted	209,072,232	129,301,817	190,745,688	104,125,317
Net loss per share of common stock attributable to common stockholders:				
Basic	$ (0.08)	$ (0.03)	$ (0.23)	$ (0.92)
Diluted	$ (0.08)	$ (0.03)	$ (0.23)	$ (0.92)
Common shares excluded from denominator as anti-dilutive:				
Unvested restricted shares	553,671	170,362	750,499	540,994
Unvested PBUs	1,654,841	1,041,493	713,911	837,199
Convertible notes	73,520,769	—	63,319,752	—
Total	75,729,281	1,211,855	64,784,162	1,378,193

11. Commitments and Contingencies

Litigation

Gastar Exploration Inc. v. Christopher McArthur (Cause No.: 2015-77605) 157th Judicial District Court, Harris County, Texas. On December 29, 2015, Gastar filed suit against Christopher McArthur ("McArthur") in the District Court of Harris County, Texas. The lawsuit arises from a demand letter sent by McArthur to Gastar in which he claimed to be party to an agreement with Gastar that entitled him to be paid $2.75 million for services rendered. In August 2016, McArthur filed an amended answer admitting he had no agreement with the Company. As a result, Gastar believes McArthur's claim has been effectively resolved. Gastar has continued to pursue a counterclaim in this action against McArthur for tortious interference with an existing contract. McArthur has filed a general denial.

Torchlight Energy Resources, Inc., Torchlight Energy, Inc. v. Husky Ventures, Inc., et al., (Cause No. 429-01961-2016) 429th Judicial District Court in Collin County, Texas. Torchlight Energy Resources, Inc. and Torchlight Energy, Inc. (collectively "Torchlight") brought a lawsuit against the Company, two of its executive officers, its chairman of the board of directors and a former director of the Company on May 3, 2016 in Collin County, Texas (the "Torchlight Lawsuit"). The Torchlight Lawsuit arises primarily out of Torchlight's business dealings with Husky Ventures, Inc. ("Husky") in Oklahoma. Husky and several of its employees and affiliates are also defendants in the Torchlight Lawsuit. As part of settlement negotiations between Husky and the Company in a separate lawsuit, Husky informed the Company that it had agreed to repurchase assets from Torchlight that Husky had previously sold to Torchlight (the "Torchlight Assets"). Husky offered to sell those Torchlight Assets to the Company. In the Purchase and Sale Agreement between Torchlight and Husky (the "Purchase and Sale Agreement"), Torchlight expressly acknowledged that the Torchlight Assets were to be sold to the Company and released the Company from any claims arising out of the sale of the Torchlight Assets. Despite this release, Torchlight alleged multiple causes of action against the Company and its officers and directors arising out of the sale of the Torchlight Assets and Torchlight's other business dealings it had with Husky.

On August 17, 2016, Plaintiffs nonsuited, without prejudice, their claims against the former chairman of the board. On May 22, 2017, the court granted the Company's motion for summary judgment and dismissed all of the Plaintiffs' claims against the Company and the Company's other officers and directors in their entirety. The Company has also filed a counterclaim against Torchlight for breach of the release in the Purchase and Sale Agreement which is still pending.

PennMarc Resources II, LP, et al v. Gastar Exploration USA, Inc., et al, (Civil Action No. 17-C-214) Circuit Court of Marshall County, West Virginia. PennMarc Resources II, LP and others filed suit against the Company on October 23, 2017 in the Circuit Court of Marshall County, West Virginia. The plaintiffs are royalty owners under various leases taken by or assigned to the Company. The leases cover property in Marshall County, West Virginia. The leases are among other assets that were assigned to THQ Appalachia, LLC pursuant to a purchase and sale agreement dated February 12, 2016. The plaintiffs allege that the Company breached the leases by making deductions for post-production costs that were not authorized by the terms of the leases. The plaintiffs also allege that the unauthorized deductions were not shown on the monthly royalty statements and the failure to detail the deduction of these costs was a further breach of the leases and fraud. The plaintiffs claim of breach of contract, breach of fiduciary duty and fraudulent concealment. The plaintiffs seek compensatory damages and punitive damages. The Company is still assessing this claim and has not yet filed a response.

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.

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 Nine Months Ended September 30,	
	2017	2016
	(in thousands)	
Cash paid for interest, net of capitalized amounts	$ 17,770	$ 16,140
Non-cash transactions:		
Capital expenditures included in accounts payable and accrued drilling costs	$ 12,176	$ 4,913
Capital expenditures included in accounts receivable	$ 76	$ 409
Asset retirement obligation included in oil and natural gas properties	$ 403	$ 92
Asset retirement obligation sold	$ (1,533)	$ (694)
Application of advances to operators	$ 24	$ (378)
Non-cash financing charges excluded from accounts payable and accrued liabilities	$ 19	$ —
Expenses accrued for issuance of common stock	$ —	$ 2
Undeclared cumulative dividends on preferred stock	$ 2,412	$ 7,237
Conversion of convertible debt to equity	$ 37,500	$ —

13. Subsequent Events

Pursuant to Amendment No. 2, on October 2, 2017, the Company elected to pay in kind 100% of the interest due for the period June 30, 2017 to October 1, 2017 in the amount of $6.6 million, thus increasing the outstanding principal balance of the Term Loan to $256.6 million at such time.

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,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target” or “continue,” the negative of such terms or variations thereon, or 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 condition;
- cash flow and liquidity;
- timing and results of property acquisitions and divestitures;
- business strategy and budgets;
- capital expenditures;
- drilling of wells, including the 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;
- availability of capital; and
- prospect development.

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, including risks of low commodity prices affecting the benefits of the Development Agreement;
- our financial condition, results of operations, revenues, cash flows and expenses;
- the potential need to sell certain assets, restructure our debt or raise additional capital;
- the need to take ceiling test impairments due to lower commodity prices;
- 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 monetize certain assets;
- our ability to raise capital to fund capital expenditures, service our indebtedness or repay or refinance debt upon maturity;
- 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 co-participants to fund any or all of th eir portion of any capital program;
- the ability to find, acquire, 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;
- 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 II, Item 1A. “Risk Factors” and elsewhere in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2017 and June 30, 2017, (iii) Part I, Item 1A. “Risk Factors” and elsewhere in our 2016 Form 10-K, (iv) our subsequent reports and registration statements filed from time to time with the SEC and (v) 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 a pure play Mid-Continent independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and NGLs. 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. We hold a concentrated acreage position in the normally pressured oil window of the STACK Play, an area of central Oklahoma which is home to multiple oil and natural gas-rich reservoirs including Meramec and Osage formations within the Mississippi Lime, the Oswego limestone, the Woodford shale and Hunton limestone formations. On April 8, 2016, we sold substantially all of our producing assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for an adjusted sales price of $75.7 million, net of $3.5 million of suspense liability transferred to buyer, with an effective date of January 1, 2016 (the "Appalachian Basin Sale"). We sold our remaining Appalachian Basin interests on January 20, 2017 (effective January 1, 2017) for approximately $200,000 before fees and expenses.

Our current operational activities are conducted in, and our consolidated revenues are generated from, markets exclusively in the U.S. As of September 30, 2017, our major assets consist of approximately 132,400 gross (91,400 net) acres in Oklahoma (29% undeveloped) of which approximately 99,900 gross (65,200 net) acres are deemed to have multi-STACK Play potential.

The following discussion addresses material changes in our results of operations for the three and nine months ended September 30, 2017 compared to the three and nine months ended September 30, 2016 and material changes in our financial condition since December 31, 2016. 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 2016 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" of our 2016 Form 10-K.

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 the Mid-Continent area, there is no assurance that new drilling opportunities will be identified or that any new drilling opportunities will be successful if drilled.

Mid-Continent Horizontal Oil Play.

We believe that our acreage is prospective in the normally pressured oil window of the STACK Play, an area of central Oklahoma that includes oil and natural gas-rich formations such as the Meramec, Osage and Woodford Shale, ranging in depth from 6,000 to 9,000 feet, and in the shallow Oswego formation as well as the proven Hunton limestone horizontal oil play. We believe that the STACK Play is one of the most economic plays in North America. It is a horizontal drilling play in an area of previously drilled vertical wells with multiple productive reservoirs that are predominantly oil producing. The STACK Play encompasses all or parts of Blaine, Canadian, Garfield, Kingfisher and Major counties in Oklahoma. STACK is an acronym for Sooner Trend Anadarko basin Canadian and Kingfisher counties. At September 30, 2017, we held leases covering approximately 132,400 gross (91,400 net) acres in Garfield, Kingfisher, Logan, Blaine and Oklahoma Counties, Oklahoma within the STACK Play.

Our initial leasing activities in 2012 were primarily focused in northwest Kingfisher County, Oklahoma with an AMI co-participant whom we bought out and assumed operatorship of the acquired wells in December 2015 (the "Husky Acquisition").

On October 14, 2016, we executed a definitive agreement with STACK Exploration LLC (the "Investor") to jointly develop up to 60 Gastar operated wells in the STACK Play in Kingfisher County, Oklahoma (the "Development Agreement"). The drilling program (the "Drilling Program") targeted the Meramec and Osage formations within the Mississippi Lime in a contract area within three townships covering approximately 32,900 gross (21,200 net) undeveloped net mineral acres under leases held by us. We serve as operator of all wells jointly developed under the Development Agreement.

Under the Development Agreement, the Investor funded 90% of our working interest portion of drilling and completion costs to initially earn 80% of our working interest in each new well (in each case, proportionately reduced by other participating working interests in the well). As a result, we paid 10% of our working interest portion of such costs for 20% of our original working interest in the well.

The Drilling Program wells were to be mutually developed in three tranches of 20 wells each. The locations of the first 20 wells, comprised of 18 Meramec formation wells and two Osage formation wells, were mutually agreed upon by us and the Investor. Participation in the second tranche of 20 Drilling Program wells was to be at the election of the Investor and the third tranche of 20 wells was to require mutual consent. As of July 31, 2017, the Investor elected not to participate in a second tranche of wells.

With respect to each 20 well tranche drilled, when the Investor has achieved an aggregate 15% internal rate of return for its investment in the tranche, its interest will be reduced from 80% to 40% of our original w orking interest and our working interest increases from 20% to 60% of our original working interest. When a tranche internal rate of return of 20% is achieved by the Investor, Investor's working interest decreases to 10% and our working interest increases to 90% of the working interest originally owned by us.

After final reversion of each tranche (the "WI Tail"), the Investor has the right, but not the obligation, for a period of six months after final reversion to cause us to purchase the Investor's WI Tail in the Drilling Program for such tranche (the "Investor Put Right") for fair market value by applying the methodology to determine a 15% discounted present value as defined by the Development Agreement. If the Investor fails to exercise the Investor Put Right within the six-month period after achieving final reversion, then for a period of six months thereafter, we shall have the right, but not the obligation, to purchase the WI Tail from the Investor on the same fair market value approach of the Investor Put Right. If final reversion has not been achieved by the eighth anniversary of the spud date of the first well in a given tranche, Investor will, for a period of six months thereafter, have the right to cause us to buy Investor's then-current interest in such tranche at an agreed upon valuation. Based on current commodity prices, well cost and production performance of the wells in the first tranche, the 15% internal rate of return is not anticipated to be achieved.

As of September 30, 2017, we had drilled and completed 20 gross (3.2 net) wells under the first tranche of the Development Agreement, all of which were on production.

On October 19, 2016, we entered into a purchase and sale agreement to sell certain non-core leasehold interests in approximately 25,300 net acres of which only 19,100 net acres was ascribed allocated value and interests in 25 gross (11.2 net) wells primarily in northeast Canadian County and also in southeast Kingfisher County, Oklahoma to Red Bluff Resources Operating, LLC, a Delaware limited liability company, ("Red Bluff") for $71.0 million (of which up to $10.0 million was contingent upon the satisfaction of certain conditions), subject to certain adjustments and with a property sale effective date of August 1, 2016 ("South STACK Play Acreage Sale"). On November 18, 2016, we and Red Bluff executed and delivered two amendments to the sale agreement and entered into a relating closing agreement, which, among other things, allocated $1.4 million of the purchase price to producing properties with the remainder of the purchase price to non-producing properties. As of September 30, 2017, we had completed the sale and received approximately $69.5 million of the South STACK Play Acreage Sale proceeds.

During the three and nine months ended September 30, 2017, Gastar spud four gross (2.9 net) and 10 gross (3.8 net) operated Meramec wells, respectively, and commenced flow back on one gross (0.2 net) and 14 gross (2.2 net) operated Meramec wells, respectively.

During the three and nine months ended September 30, 2017, Gastar spud two gross (1.4 net) and 13 gross (9.8 net) operated Osage wells, respectively, and commenced flow back on four gross (2.8 net) and eight gross (5.8 net) operated Osage wells, respectively. Subsequent to September 30, 2017 through October 31, 2017, Gastar spud two gross (1.2 net) operated Osage wells and commenced flow back on four gross (3.2 net) operated Osage wells.]

During 2017, we have elected to participate in various non-operated wells in the Meramec, Osage and Oswego formations to further delineate our STACK Play acreage position. Of the 2017 non-operated wells that we have elected to participate, currently two gross (0.3 net) non-operated Meramec wells and one gross (0.1 net) non-operated Osage wells have been placed on production. We anticipate that we will continue to receive election notices regarding proposed non-operated STACK wells.

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

Mid-Continent	For the Three Months Ended September 30, 2017	2016	For the Nine Months Ended September 30, 2017	2016
Net Production:				
Oil and condensate (MBbl)	278	242	805	790
Natural gas (MMcf)	962	997	2,746	2,917
NGLs (MBbl)	134	128	379	380
Total net production (MBoe)	572	537	1,642	1,656
Net Daily Production:				
Oil and condensate (MBbl/d)	3.0	2.6	3.0	2.9
Natural gas (MMcf/d)	10.5	10.8	10.1	10.6
NGLs (MBbl/d)	1.5	1.4	1.4	1.4
Total net daily production (MBoe/d)	6.2	5.8	6.0	6.0
Average sales price per unit (1) :				
Oil and condensate (per Bbl)	$ 46.56	$ 42.56	$ 47.03	$ 37.87
Natural gas (per Mcf)	$ 2.62	$ 2.48	$ 2.71	$ 2.06
NGLs (per Bbl)	$ 20.64	$ 13.22	$ 19.87	$ 12.79
Average sales price per Boe (1)	$ 31.86	$ 26.98	$ 32.19	$ 24.63
Selected operating expenses (in thousands):				
Production taxes	$ 721	$ 398	$ 1,691	$ 1,154
Lease operating expenses	$ 6,179	$ 5,044	$ 16,399	$ 15,007
Transportation, treating and gathering	$ 437	$ 337	$ 1,187	$ 730
Selected operating expenses per Boe:				
Production taxes	$ 1.26	$ 0.74	$ 1.03	$ 0.70
Lease operating expenses	$ 10.80	$ 9.40	$ 9.99	$ 9.06
Transportation, treating and gathering	$ 0.76	$ 0.63	$ 0.72	$ 0.44
Production costs (2)	$ 11.56	$ 10.03	$ 10.71	$ 9.50

(1) Excludes the impact of hedging activities.

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

Appalachian Basin.

On April 8, 2016, we sold substantially all of our producing assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for an adjusted price of $75.7 million, net of $3.5 million of suspense liability transferred to buyer. On January 20, 2017, we sold our remaining interest in producing assets and leasehold in the Appalachian Basin, effective January 1, 2017, for $200,000 before fees and expenses.

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.

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

	For the Three Months Ended September 30, 2017	For the Three Months Ended September 30, 2016	For the Nine Months Ended September 30, 2017	For the Nine Months Ended September 30, 2016 (1)
	(In thousands, except per unit amounts)			
Net Production:				
Oil and condensate (MBbl)	278	242	805	837
Natural gas (MMcf)	962	1,009	2,748	5,232
NGLs (MBbl)	134	128	379	616
Total net production (MBoe)	572	539	1,642	2,325
Net Daily production:				
Oil and condensate (MBbl/d)	3.0	2.6	3.0	3.1
Natural gas (MMcf/d)	10.5	11.0	10.1	19.1
NGLs (MBbl/d)	1.5	1.4	1.4	2.2
Total net daily production (MBoe/d)	6.2	5.9	6.0	8.5
Average sales price per unit:				
Oil and condensate per Bbl, excluding impact of hedging activities	$ 46.56	$ 42.55	$ 47.03	$ 36.41
Oil and condensate per Bbl, including impact of hedging activities (2)	$ 51.77	$ 47.19	$ 52.78	$ 43.85
Natural gas per Mcf, excluding impact of hedging activities	$ 2.62	$ 2.48	$ 2.71	$ 1.60
Natural gas per Mcf, including impact of hedging activities (2)	$ 2.69	$ 2.76	$ 2.80	$ 1.86
NGLs per Bbl, excluding impact of hedging activities	$ 20.64	$ 13.22	$ 19.87	$ 8.28
NGLs per Bbl, including impact of hedging activities (2)	$ 22.55	$ 15.01	$ 22.02	$ 10.55
Average sales price per Boe, excluding impact of hedging activities	$ 31.86	$ 26.92	$ 32.19	$ 18.91
Average sales price per Boe, including impact of hedging activities (2)	$ 34.96	$ 29.96	$ 35.65	$ 22.77
Selected operating expenses:				
Production taxes	$ 721	$ 400	$ 1,675	$ 1,469
Lease operating expenses	$ 6,178	$ 5,166	$ 16,396	$ 15,829
Transportation, treating and gathering	$ 436	$ 338	$ 1,187	$ 1,346
Depreciation, depletion and amortization	$ 6,059	$ 5,223	$ 16,762	$ 24,543
Impairment of natural gas and oil properties	$ —	$ —	$ —	$ 48,497
General and administrative expense	$ 4,067	$ 3,925	$ 12,482	$ 15,872
Selected operating expenses per Boe:				
Production taxes	$ 1.26	$ 0.74	$ 1.02	$ 0.63
Lease operating expenses	$ 10.80	$ 9.59	$ 9.98	$ 6.81
Transportation, treating and gathering	$ 0.76	$ 0.63	$ 0.72	$ 0.58
Depreciation, depletion and amortization	$ 10.59	$ 9.70	$ 10.21	$ 10.56
General and administrative expense	$ 7.11	$ 7.29	$ 7.60	$ 6.83
Production costs (3)	$ 11.56	$ 10.11	$ 10.71	$ 7.37

(1) The nine months ended September 30, 2016 includes Appalachian Basin production and pricing and the sale of substantially all of the producing assets and undeveloped leasehold was completed on April 8, 2016.
(2) The impact of hedging includes the gain (loss) on commodity derivative contracts settled during the periods presented.
(3) Production costs include LOE, insurance, gathering and workover expense and exclude ad valorem and severance taxes.

Three Months E nded September 30, 2017 compared to the Three Months Ended September 30, 2016

Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) as reported were $18.2 million for the three months ended September 30, 2017, up 26% from $14.5 million for the three months ended September 30, 2016. The increase in revenues was the result of an 18% increase in weighted average realized equivalent prices coupled with a 6% increase in production. Average daily production on an equivalent basis was 6.2 MBoe/d for the three months ended September 30, 2017 compared to 5.9 MBoe/d for the same period in 2016. Oil, condensate and NGLs production represented approximately 72% of total production for the three months ended September 30, 2017 compared to 69% of total production for the three months ended September 30, 2016.

Oil and condensate revenues represented approximately 71% of our total oil, condensate, natural gas and NGLs revenues for the three months ended September 30, 2017 and 2016. Total liquids revenues (oil, condensate and NGLs) represented approximately 86% of our total oil, condensate, natural gas and NGLs revenues for the three months ended September 30, 2017 and 83% of our total oil, condensate, natural gas and NGLs revenues for the three months ended September 30, 2016.

During the three months ended September 30, 2017, we had commodity derivative contracts covering approximately 48% of our oil and condensate production. The impact of hedging on oil and condensate sales during the three months ended September 30, 2017 was an increase of $1.4 million in oil and condensate revenues and resulted in an increase in total price realized from $46.56 per Bbl to $51.77 per Bbl. The gain on oil and condensate commodity derivatives contracts settled during the period was reduced by $313,000 for deferred put premiums. During the three months ended September 30, 2016, the impact of hedging on oil and condensate sales was an increase of $1.1 million, which resulted in an increase in total price realized from $42.55 per Bbl to $47.19 per Bbl. We allocated 15% of our crude hedges as price protection for our NGLs production for the quarters ended September 30, 2017 and 2016. We have not designated any of these derivatives contracts as hedges as prescribed by accounting rules.

During the three months ended September 30, 2017, we had commodity derivative contracts covering approximately 70% of our natural gas production. The impact of hedging on natural gas sales during the three months ended September 30, 2017 was an increase of $72,000 in natural gas revenues and resulted in an increase in total price realized from $2.62 per Mcf to $2.69 per Mcf. The gain on natural gas commodity derivatives contracts settled during the period was reduced by $34,000 for deferred put premiums. During the three months ended September 30, 2016, the impact of hedging on natural gas sales was an increase of $283,000, which resulted in an increase in total price realized from $2.48 per Mcf to $2.76 per Mcf. We have not designated any of these derivatives contracts as hedges as prescribed by accounting rules.

During the three months ended September 30, 2017, we had commodity derivative contracts covering approximately 18% of our NGLs production. The impact of hedging on NGLs sales during the three months ended September 30, 2017 was an increase of $256,000 in NGLs revenues and resulted in an increase in total price realized from $20.64 per Bbl to $22.55 per Bbl. The gain on NGLs commodity derivatives contracts settled during the period was reduced by $55,000 for deferred put premiums. During the three months ended September 30, 2016, the impact of hedging on NGLs sales was an increase of $230,000 in NGLs revenues which resulted in an increase in total price realized from $13.22 per Bbl to $15.01 per Bbl. We have not designated any of these derivatives contracts as hedges as prescribed by accounting rules.

The change in mark to market value for outstanding commodity derivatives contracts for the three months ended September 30, 2017 was a loss of $4.7 million compared to a loss of $3.1 million for the three months ended September 30, 2016. The change in the mark to market value is primarily the result of changes in hedge contracts and volumes hedged and the future price curve compared to the prior year.

For additional information regarding our oil and condensate hedging positions as of September 30, 2017, see Part I, Item 1. “Financial Statements, Note 6 – Derivative Instruments and Hedging Activity” of this report.

Production taxes. We reported production taxes of $721,000 for the three months ended September 30, 2017 compared to $400,000 for the three months ended September 30, 2016. The increase in production taxes primarily resulted from new Mid-Continent wells, increases in Oklahoma production tax exemption rates on certain horizontal wells and increased revenues resulting from higher prices as well as the expiration of tax exemptions on older drilled wells. Production taxes for the three months ended September 30, 2017 and 2016 were approximately 4.0% and 2.8%, respectively, of oil, condensate, natural gas and NGLs revenues.

Lease operating expenses. We reported LOE of $6.2 million for the three months ended September 30, 2017 compared to $5.2 million for the three months ended September 30, 2016. Our total LOE was $10.80 per Boe for the three months ended September 30, 2017 compared to $9.59 per Boe for the same period in 2016. The increase in LOE is due primarily to a $553,000 ($0.97 per Boe) increase in workover expense and a $512,000 ($0.89 per Boe) increase in controllable LOE.

Transportation, treating and gathering. We reported transportation expenses of $436,000 for the three months ended September 30, 2017 compared to $338,000 for the three months ended September 30, 2 016 due primarily to new wells and changes in Oklahoma marketing contracts from percent of proceeds to more fixed charges basis.

Depreciation, depletion and amortization. We reported depreciation, depletion and amortization ("DD&A") expense of $6.1 million for the three months ended September 30, 2017 up from $5.2 million for the three months ended September 30, 2016. The increase in DD&A expense was the result of a 9% increase in the DD&A rate due to increased costs on wells that resulted in lower reserves coupled with a 6% increase in production. The DD&A rate for the three months ended September 30, 2017 was $10.59 per Boe compared to $9.70 per Boe for the same period in 2016.

General and administrative expense. We reported general and administrative expenses of $4.1 million for the three months ended September 30, 2017 compared to $3.9 million for the three months ended September 30, 2016. Non-cash stock-based compensation expense, which is included in general and administrative expense, was $1.8 million and $810,000 for the three months ended September 30, 2017 and 2016, respectively. Excluding stock-based compensation expense, general and administrative expense decreased $839,000 to $2.3 million for the three months ended September 30, 2017 compared to the three months ended September 30, 2016. This decrease is primarily due to lower legal fees and acquisition costs coupled with a West Virginia franchise tax refund.

Litigation settlement benefit. We reported a litigation settlement benefit of $10.1 million for the three months ended September 30, 2016 for recovery in connection with a legal settlement with our insurers regarding a claim previously denied under our directors and officers liability insurance coverage to recover settlement and legal defense expenses incurred by us in connection with litigation settled in December 2010.

Interest expense. We reported interest expense of $10.2 million for the three months ended September 30, 2017 compared to $8.2 million for the three months ended September 30, 2016. The increase in interest expense is due primarily to changes in and the terms of the new debt instruments.

Dividends on preferred stock. Dividends on preferred stock totaled $1.2 million for the three months ended September 30, 2017 comprised of $727,000 for Series A Preferred Stock and $479,000 for the Series B Preferred Stock. Accumulated undeclared and unpaid dividends totaled $2.4 million for the three months ended September 30, 2017 comprised of $1.5 million for the Series A Preferred Stock and $959,000 for the Series B Preferred Stock compared to $3.6 million for the three months ended September 30, 2016 comprised of $2.2 million for the Series A Preferred Stock and $1.4 million for the Series B Preferred Stock.

Nine Months Ended September 30, 2017 compared to the Nine Months Ended September 30, 2016

Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) as reported were $52.9 million for the nine months ended September 30, 2017, up 20% from $44.0 million for the nine months ended September 30, 2016. The increase in revenues was primarily the result of a 70% increase in weighted average realized equivalent prices partially offset by a 29% decrease in production. The decrease in production was primarily the result of the Appalachian Basin Sale on April 8, 2016. Average daily production on an equivalent basis was 6.0 MBoe/d for the nine months ended September 30, 2017 compared to 8.5 MBoe/d for the same period in 2016, of which Appalachian Basin production was 2.4 MBoe/d. Oil, condensate and NGLs production represented approximately 72% of total production for the nine months ended September 30, 2017 compared to 62% of total production for the nine months ended September 30, 2016. Excluding the impact of the Appalachian Basin production sales on oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging), total oil, condensate, natural gas and NGLs revenues increased $12.1 million, or 30%, for the nine months ended September 30, 2017 from the nine months ended September 30, 2016 as a result of a 31% increase in weighted average realized equivalent prices in the Mid-Continent partially offset by a 1% decrease in average daily equivalent production in the Mid-Continent.

Oil and condensate revenues represented approximately 72% of our total oil, condensate, natural gas and NGLs revenues for the nine months ended September 30, 2017 compared to 69% for the nine months ended September 30, 2016 as reported and 73% for the nine months ended September 30, 2016 excluding the impact of Appalachian Basin production. Total liquids revenues (oil, condensate and NGLs) represented approximately 86% of our total oil, condensate, natural gas and NGLs revenues for the nine months ended September 30, 2017 and 81% of our total oil, condensate, natural gas and NGLs revenues for the nine months ended September 30, 2016 as reported and 85% excluding the impact of Appalachian Basin production.

During the nine months ended September 30, 2017, we had commodity derivative contracts covering approximately 59% of our oil and condensate production. The impact of hedging on oil and condensate sales during the nine months ended September 30, 2017 was an increase of $4.6 million in oil and condensate revenues and resulted in an increase in total price realized from $47.03 per Bbl to $52.78 per Bbl. The gain on oil and condensate commodity derivatives contracts settled during the period was reduced by $1.4 million for deferred put premiums. During the nine months ended September 30, 2016, the impact of hedging on oil and condensate sales was an increase of $6.2 million, which resulted in an increase in total price realized from $36.41 per Bbl to $43.85 per Bbl. We allocated 15% of our crude hedges as price protection for our NGLs production for the nine months ended September 30, 2017 and 2016. We have not designated any of these derivatives contracts as hedges as prescribed by accounting rules.

During the nine months ended September 30, 2017, we had commodity derivative contracts covering approximately 62% of our natural gas production. The impact of hedging on natural gas sales during the nine months ended September 30, 2017 was an increase of $235,000 in natural gas revenues and resulted in an increase in total price realized from $2.71 per Mcf to $2.80 per Mcf. The gain on natural gas commodity derivatives contracts settled during the period was reduced by $101,000 for deferred put premiums. During the nine months ended September 30, 2016, the impact of hedging on natural gas sales was an increase of $1.4 million in natural gas revenues resulting in an increase in total price realized from $1.60 per Mcf to $1.86 per Mcf. We have not designated any of these derivatives contracts as hedges as prescribed by accounting rules.

During the nine months ended September 30, 2017, we had commodity derivative contracts covering approximately 22% of our NGLs production. The impact of hedging on NGLs sales during the nine months ended September 30, 2017 was an increase of $817,000 in NGLs revenues and resulted in an increase in total price realized from $19.87 per Bbl to $22.02 per Bbl. The gain on NGLs commodity derivatives contracts settled during the period was reduced by $243,000 for deferred put premiums. During the nine months ended September 30, 2016, the impact of hedging on NGLs sales was an increase of $1.4 million in NGLs revenues which resulted in an increase in total price realized from $8.28 per Bbl to $10.55 per Bbl. We have not designated any of these derivatives contracts as hedges as prescribed by accounting rules.

The change in mark to market value for outstanding commodity derivatives contracts for the nine months ended September 30, 2017 was a loss of $1.9 million compared to a loss of $13.0 million for the nine months ended September 30, 2016. The change in the mark to market value is primarily the result of changes in hedge contracts and volumes hedged and the future price curve compared to the prior year.

For additional information regarding our oil and condensate hedging positions as of September 30, 2017, 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 nine months ended September 30, 2017 compared to $1.5 million for the nine months ended September 30, 2016. Excluding the Appalachian Basin, production taxes increased $537,000, or 46%, for the nine months ended September 30, 2017 from the nine months ended September 30, 2016 primarily due to new wells, increases in Oklahoma production tax exemption rates on certain horizontal wells, increased revenues resulting from higher prices and the expiration of tax exemptions on older drilled wells. As reported, production taxes for the nine months ended September 30, 2017 and 2016 were approximately 3.2% and 3.3%, respectively, of oil, condensate, natural gas and NGLs revenues. Excluding the Appalachian Basin, production taxes were approximately 2.8% of oil, condensate, natural gas and NGLs revenues for the nine months ended September 30, 2016.

Lease operating expenses. We reported LOE of $16.4 million for the nine months ended September 30, 2017 compared to $15.8 million for the nine months ended September 30, 2016. Our total LOE, as reported, was $9.98 per Boe for the nine months ended September 30, 2017 compared to $6.81 per Boe for the same period in 2016. Excluding the Appalachian Basin, LOE per Boe for the nine months ended September 30, 2016 was $9.06. Excluding the Appalachian Basin, LOE increased $1.4 million, or 9%, for the nine months ended September 30, 2017 from the nine months ended September 30, 2016 due primarily to a $1.2 million increase in workover expense.

Transportation, treating and gathering. We reported transportation expenses of $1.2 million for the nine months ended September 30, 2017 compared to $1.3 million for the nine months ended September 30, 2016. Excluding the Appalachian Basin, transportation expense in the Mid-Continent increased $458,000 for the nine months ended September 30, 2017 compared to the nine months ended September 30, 2016 due to new wells and changes in Oklahoma marketing contracts from percent of proceeds to more fixed charges basis.

Depreciation, depletion and amortization. We reported DD&A expense of $16.8 million for the nine months ended September 30, 2017 down from $24.5 million for the nine months ended September 30, 2016. The decrease in DD&A expense was the result of a 29% decrease in production resulting from the completion of the Appalachian Basin Sale coupled with a lower DD&A rate due to the impairment charge incurred in the first quarter 2016 and the credit to the full cost pool for the net proceeds from the Appalachian Basin Sale and South STACK Play Acreage Sale. The DD&A rate for the nine months ended September 30, 2017 was $10.21 per Boe compared to $10.56 per Boe for the same period in 2016.

General and administrative expense. We reported general and administrative expenses of $12.5 million for the nine months ended September 30, 2017 compared to $15.9 million for the nine months ended September 30, 2016. Non-cash stock-based compensation expense, which is included in general and administrative expense, was $4.0 million and $3.1 million for the nine months ended September 30, 2017 and 2016, respectively. Excluding stock-based compensation expense, general and administrative expense decreased $4.2 million to $8.5 million for the nine months ended September 30, 2017 compared to the nine months ended September 30, 2016. This decrease is primarily due to $2.0 million of bad debt expense recorded in 2016 coupled with lower legal costs, lower acquisition costs related to the Husky Acquisition and reduced personnel costs as a resul t of the sale of our Appalachian Basin assets.

Litigation settlement benefit. We reported a litigation settlement benefit of $10.1 million for the nine months ended September 30, 2016 for recovery in connection with a legal settlement with our insurers regarding a claim previously denied under our directors and officers liability insurance coverage to recover settlement and legal defense expenses incurred by us in connection with litigation settled in December 2010.

Interest expense. We reported interest expense of $29.7 million for the nine months ended September 30, 2017 compared to $26.7 million for the nine months ended September 30, 2016. The increase in interest expense is primarily due to increased borrowings under the Convertible Notes due 2022 (the "Notes") and the Term Loan (as defined below) at higher interest rates coupled with additional amortization of deferred financing costs partially offset by higher capitalized interest.

Loss on early extinguishment of debt. We reported a loss on early extinguishment of debt of $12.2 million for the nine months ended September 30, 2017 comprised of a $7.0 million penalty for the early satisfaction and discharge of our 8 5/8% Senior Secured Notes due May 15, 2018 (the "Former Notes") and the $5.2 million write-off of the remaining deferred financing costs related to the Former Notes and our former revolving credit facility under 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").

Dividends on preferred stock. We reported dividends on preferred stock of $8.4 million for the nine months ended September 30, 2017, comprised of $5.1 million for the Series A Preferred Stock and $3.3 million for the Series B Preferred Stock and $3.6 million for the nine months ended September 30, 2016 comprised of $2.2 million for the Series A Preferred Stock and $1.4 million for the Series B Preferred Stock. Accumulated undeclared and unpaid dividends totaled $2.4 million for the nine months ended September 30, 2017 comprised of $1.5 million for the Series A Preferred Stock and $959,000 for the Series B Preferred Stock compared to undeclared cumulative dividends on preferred stock of $7.2 million for the nine months ended September 30, 2016 comprised of $4.4 million for the Series A Preferred Stock and $2.8 million for the Series B Preferred Stock.

Liquidity and Capital Resources

Overview. Our primary sources of liquidity and capital resources are existing cash balances, internally generated cash flows from operating activities, possible asset sales and capital markets transactions, to the extent available on acceptable terms. We believe that our current cash position and funds from operating cash flows and possible future property sales should be sufficient to meet our cash requirements for the remainder of 2017 and to late 2018. We continually evaluate our capital needs and compare them to our capital resources and ability to raise funds in the financial markets or through the sale of certain non-STACK assets. We have the ability to adjust capital expenditures in response to changes in oil, condensate, natural gas and NGLs prices, drilling results, liquidity and cash flow as we operate the majority of our capital expenditures budget. Current market conditions and restrictions under our new debt may put limitations on our ability to issue new debt or equity securities in the public or private markets.

On March 3, 2017, certain funds (the "Purchasers") managed indirectly by Ares Management LLC ("Ares"), purchased from us for cash (i) $125.0 million aggregate principal amount of our Notes sold at par, which Notes, subject to the receipt of approval of our stockholders, which was obtained on May 2, 2017, are convertible into our common stock, par value $0.001 per share (the "Common Stock") or, in certain circumstances, cash in lieu of Common Stock or a combination thereof as described below and (ii) 29,408,305 shares of Common Stock for a cash purchase price of $50.0 million. In addition, affiliates of Ares concurrently loaned us $250.0 million pursuant to the Term Loan (as described below). On such date, a portion of the net proceeds from these Ares transactions was used to repay all of our outstanding borrowings under our Revolving Credit Facility (which was terminated on such date), and the redemption price plus interest of all of our outstanding $325.0 million principal of the Former Notes was funded to satisfy and discharge the Former Notes, which were satisfied and discharged on March 3, 2017. On March 21, 2017, we issued an additional $75.0 million principal amount of Notes at par to Ares (the "Additional Notes"). Pursuant to the purchase agreement for the Additional Notes, upon the receipt of approval of holders of our issued and outstanding common stock (other than the Purchasers) (the "Requisite Stockholder Approval"), we would repurchase $37.5 million principal amount of the Additional Notes for (a) 25,456,521 shares of our common stock and (b) 2,000 shares of our Special Voting Preferred Stock (the "Mandatory Repurchase"), with the remainder convertible into our common stock or, in certain circumstances, cash in lieu of common stock or a combination thereof. Requisite Stockholder Approval was obtained on May 2, 2017 at a special meeting of common stockholders. The Mandatory Repurchase was completed on May 5, 2017.

For the nine months ended September 30, 2017, we reported cash flows provided by operating activities of $9.1 million. For the nine months ended September 30, 2017, we reported net cash used in investing activities of $109.9 million primarily for the acquisition of oil and natural gas properties of $54.5 million and $81.9 milli on for the development of oil and natural gas properties partially offset by $28.8 million of proceeds from the sale of oil and natural gas properties. For the nine months ended September 30, 2017, we reported net cash provided by financing activities of $58.5 million, consisting primarily of $450.0 million of new borrowings under the Ares transactions and $56.6 million of proceeds from the issuance of common equity partially offset by $409.6 million of repayment of borrowings under our Revolving Credit Fa cility and the full pay-off of the Former Notes, $19.3 million of preferred stock dividends paid, $11.0 million of deferred financing charges and a $7.0 million payment for the early extinguishment of debt. As a result of these activities, our cash and ca sh equivalents balance decreased by $42.3 million, resulting in a cash and cash equivalents balance of $29.2 million at September 30, 2017.

At September 30, 2017, we had a net working capital surplus of approximately $21.9 million. As of November 3, 2017, our cash balance was $20.7 million.

Future capital and other expenditure requirements. Total capital expenditures for 2017 are currently projected to not exceed the previously announced full-year budget of $129.2 million. Remaining capital expenditures for 2017 are estimated to be approximately $34.7 million which contemplates $27.3 million for drilling, completions and infrastructure costs, $4.3 million for leasehold costs and $3.2 million for capitalized general and administrative costs. We plan to fund our remaining 2017 revised capital budget through existing cash balances, recent financing activities, internally generated cash flow from operating activities and possible future property sales proceeds. 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, higher working interest in drilled wells and access to additional capital. We operate the majority of our remaining budgeted 2017 capital expenditures, and thus, we could reduce a significant portion of remaining 2017 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, 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. For 2017, we allocated 15% of our current crude hedges as price protection for a portion of our NGLs production. We have not designated any of these derivative contracts as hedges as prescribed by accounting rules. 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 September 30, 2017, the estimated fair value of all of our commodity derivative instruments was a net asset of $4.4 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 October 2017 through 2019, 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 certain commodity derivative hedging activity, we deferred the payment of certain put premiums for the production month period October 2017 through December 2018. At September 30, 2017, we had a current commodity premium payable of $1.3 million and a long-term commodity premium payable of $34,000. The put premium liabilities become payable monthly as the hedge production month becomes the prompt production month.

As of September 30, 2017, all of our commodity derivative hedge positions were with large 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.

Term Loan Facility . On March 3, 2017, the Company entered into a $250.0 million Term Loan pursuant to the Third Amended and Restated Credit Agreement among the Company, as borrower, the guarantors party thereto, funds managed indirectly by Ares, as lenders, and Wilmington Trust, National Association, as Administrative Agent (the "Term Loan"). The Term Loan was issued at par and bears interest at a per annum rate equal to 8.5%, payable on a quarterly basis on each March 31, June 30, September 30 and December 31 of each year, commencing March 31, 2017, and has a scheduled maturity of March 3, 2022. In addition, the Term Loan is subject to an interest "make-whole" and repayment premium, such that any repayment or prepayment of the loans thereunder prior to the stated maturity date shall be subject to the payment of a repayment premium, and depending on the date of such repayment or prepayment, the applicable interest "make-whole" amount, with the amount of such repayment premium decreasing over the life of the Term Loan.

On March 20, 2017, we, together with the parties thereto, entered into an Amendment No. 1 to the Term Loan which amendment permitted the issuance of the Addit ional Notes.

On August 2, 2017, we entered into Amendment No. 2 allowing us to elect to PIK interest on the Term Loan, upon proper notice, 100% of interest payments due after June 30, 2017 and prior to December 1, 2018 and at our election, PIK between 0% and 50% of any interest payments occurring after December 31, 2018 (other than interest due on the maturity date or the date of any repayment or prepayment). The Term Loan interest rate increased to 10.25% for all interest periods post June 30, 2017 and the PIK interest shall be payable by capitalizing and adding such amounts to the outstanding principal amount of the Term Loan on the applicable interest payment date.

On September 18, 2017, we, together with the parties thereto, entered into Amendment No. 3 to the Term Loan, which among other things, expressly provided that certain assignments of oil and gas properties made or to be made by the Company to Red Bluff, pursuant to the Red Bluff PSA, are permitted by the Term Loan and are not subject to the mandatory prepayment provisions applicable to “Asset Sales” under the Term Loan.

The Term Loan is secured by a first-priority lien on substantially all of the assets of the Company and its sole subsidiary, excluding certain assets as customary exceptions.

The Term Loan contains various customary covenants for credit facilities of this type, including, among others, restrictions on granting liens, incurrence of other indebtedness, payments of certain dividends and other restricted payments, engaging in transactions with affiliates, dispositions of assets and other, in each case subject to certain baskets and exceptions;

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 in the Term Loan.

Pursuant to Amendment No. 2, on October 2, 2017, we elected to pay in kind 100% of the interest due for the period June 30, 2017 to October 1, 2017 in the amount of $6.6 million, thus increasing the outstanding principal balance of the Term Loan to $256.6 million at such time.

Notes. On March 3, 2017 and March 21, 2017, we issued for cash at par $125.0 million and $75.0 million, respectively, principal amounts of the Notes under an Indenture by and among the Company, the subsidiary guarantor named therein, and the Trustee and collateral trustee. The Notes bear interest initially at 6.0% per annum. On May 5, 2017, $37.5 million principal amount of the Notes were exchanged for 25,456,521 newly issued shares of our Common Stock and 2,000 shares of Special Voting Preferred Stock pursuant to the Mandatory Repurchase, reducing the outstanding principal amount of the Notes to $162.5 million. The Notes mature on March 1, 2022, unless earlier repurchased, redeemed or converted in accordance with the terms of the Indenture prior to such date. Interest is payable on the Notes on each March 1, June 1, September 1 and December 1 of each year, commencing June 1, 2017.

The Notes were issued with conversion rights that were subject to receipt of the Requisite Stockholder Approval, which was obtained at a special meeting of stockholders held May 2, 2017. The Notes are convertible at the option of the holder into shares of Common Stock based on an initial conversion price of $2.2103 per share, subject to certain adjustments and the issuance of additional “make-whole” shares under certain circumstances specified in the Indenture. Subject to certain limitations, the Company will have the right to settle its conversion obligations on the Notes in Common Stock, or in cash or a combination thereof. The Company has the right to redeem the Notes (i) on or after March 3, 2019 if the Common Stock trades above 150% of the conversion price for periods specified in the Indenture; and (ii) on or after March 1, 2021 without regard to such condition, in each case at par plus accrued interest.

The Notes are secured by a second-priority lien on substantially all of the assets of the Company. The Indenture restricts the ability of the Company and certain of its subsidiaries to, among other things: (i) pay dividends or make other distributions in respect of the Company’s capital stock or make other restricted payments; (ii) incur additional indebtedness and issue preferred stock; (iii) make certain dispositions and transfers of assets; (iv) engage in transactions with affiliates; (v) create liens; (vi) engage in certain business activities that are not related to oil and gas; and (vii) impair any security interest. These covenants are subject to a number of exceptions and qualifications.

ATM Program. We previously had an at-the-market is suance sales agreement with a third-party sales agent to sell, from time to time, shares of our Common Stock (the "ATM Program") pursuant to which we could 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 determined from time to time. Actual issuances depended 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 sou rces of funding for our company and potential uses of funding available to us. For the period January 1, 2017 to January 20, 2017, we issued an additional 5,447,919 shares of Common Stock under the ATM Program for net proceeds of $8.3 million. The ATM Pr ogram expired on February 24, 2017 and we can no longer issue and sell additional shares of Common Stock under that ATM Program.

Former Revolving Credit Facility. On March 3, 2017, we used a portion of the net proceeds from the Ares transactions described above to fully repay the $69.2 million of outstanding borrowings under our Revolving Credit Facility and terminate the facility.

Former Senior Secured Notes. On March 3, 2017, we used a portion of the net proceeds from the Ares transactions described above to satisfy and discharge the $325.0 million of our outstanding Former Notes, including $7.0 million of prepayment premium and $10.0 million of accrued interest.

Preferred Stock. Effective March 9, 2016, our Revolving Credit Facility prohibited the payment of cash dividends on our preferred stock commencing April 2016. Accordingly, we ceased payment of dividends on our Series A Preferred Stock and Series B Preferred Stock in April 2016. Dividends on the Series A Preferred Stock continued to accumulate regardless of whether any such dividends were declared or not at a fixed rate of 8.625% per annum of the aggregate $101.1 million stated value and liquidation preference. Accumulated and unpaid dividends for the Series A Preferred Stock for the period April 2016 through December 2016 totaled $6.5 million, or $1.6171875 per share, at December 31, 2016. Dividends on the Series B Preferred Stock continued to accumulate at a fixed rate of 10.75% per annum of the aggregate $53.5 million stated value and liquidation preference. Accumulated and unpaid dividends for the Series B Preferred Stock for the period April 2016 through December 2016 totaled $4.3 million, or $2.0156256 per share, at December 31, 2016.

Pursuant to Amendment No. 10 to our Revolving Credit Facility, on January 10, 2017, we declared a special cash dividend on the Series A Preferred Stock and Series B Preferred Stock to pay in full all accumulated and unpaid cash dividends since April 1, 2016 at an annualized 8.625% and 10.75%, respectively, which dividend was paid on January 31, 2017. We have subsequently declared and paid monthly cash dividends on our outstanding Series A Preferred Stock and Series B Preferred Stock through April 30, 2017. Under Amendment No. 10 to the Revolving Credit Facility, payment of the declared Series A and Series B Preferred Stock January 2017 dividend and monthly preferred stock cash dividends through May 2017 were permitted. Under the agreement governing the Term Loan and the indenture governing the Notes, cash dividend payments are permitted through July 31, 2018 contingent upon the absence of any defaults. From and after August 1, 2018, dividend payments on the outstanding Series A and Series B Preferred Stock are permitted subject to the further condition that we are in compliance with a fixed charge coverage ratio of not less than 1.0 to 1.0 from August 1, 2018, to, but excluding May 1, 2019 and of not less than 1.25 to 1.0 from and after May 1, 2019. Dividends on the Series A and Series B Preferred Stock will accumulate regardless of whether any such dividends are declared. The Series A Preferred Stock dividend is a fixed rate of 8.625% per annum of the $25.00 per share liquidation preference, or $2.15625 per share outstanding each year, and on the Series B Preferred Stock a fixed rate of 10.75% per annum of the $25.00 per share liquidation preference, or $2.6875 per share outstanding each year. If the Company fails to pay full cash dividends in four calendar quarters, whether consecutive or non-consecutive, then the fixed rate of Series A and Series B Preferred Stock each increases by 2.00% and the holders, voting as a single class, will have the right to elect up to two directors to our board of directors.

In response to the decline in oil prices and to preserve liquidity, on August 1, 2017, we elected to suspend Series A Preferred Stock and Series B Preferred Stock dividends commencing August 2017.

For the three and nine months ended September 30, 2017, we declared and paid dividends of $727,000 and $5.1 million, respectively, for the Series A Preferred Stock and $479,000 and $3.3 million, respectively, for the Series B Preferred Stock. For the three and nine months ended September 30, 2017, undeclared cumulative dividends totaled $1.5 million, respectively, for the Series A Preferred Stock and $959,000, respectively, for the Series B Preferred Stock.

Off-Balance Sheet Arrangements

As of September 30, 2017, 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
- 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 2016 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 Accounting Policies" of this report.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas, NGLs, and oil prices, and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading.

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 nine months ended September 30, 2017, a 10% change in the prices received for oil, condensate, natural gas and NGLs production would have had an approximate $1.8 million and $5.3 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

Prior to the pay-off of our Revolving Credit Facility in March 2017, we were exposed to changes in interest rates as a result of our Revolving Credit Facility. We did not enter into interest rate hedging arrangements in the past. The amount outstanding under the Term Loan is fixed at interest of 8.5% per annum prior to June 30, 2017 and 10.25% per annum after June 30, 2017 and the amount outstanding under the Notes is at fixed interest of 6.0% per annum.

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 September 30, 2017. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of September 30, 2017, 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 September 30, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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 nine months ended September 30, 2017 does not materially differ from that set out under Part I, Item 1A. "Risk Factors" in our 2016 Form 10-K. You should carefully consider the risk factors and other information discussed in our 2016 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

Issuer Purchases of Equity Securities

The following table sets forth our share repurchase activity for each period presented. Our share repurchase activity 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.

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans	(d) Maximum Number of Shares that May Yet be Purchased Under th Plan
August 1, 2017 – August 31, 2017	871	$0.58	—	n/

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosure

Not applicable.

Item 5. Other Information

On November 7, 2017, John H. Cassels gave the Company notice that he would retire as a director of the Company, effective December 31, 2017. Mr. Cassels' retirement is for personal reasons and not the result of any disagreement or other issues with the Company.

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 immediately below and such exhibits identified therein are incorporated herein by reference into this report.

EXHIBIT INDEX

Exhibit Number	Description
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	Certificate of Amendment of Amended and Restated Certificate of Incorporation of Gastar Exploration Inc. dated July 5, 2016 (incorporated by reference to Exhibit 3.2 of the Quarterly Report on Form 10-Q filed with the SEC on August 4, 2016. File No. 001-35211) .
3.3	First Certificate of Amendment of Amended and Restated Certificate of Incorporation of Gastar Exploration Inc. dated July 24, 2017 (incorporated by reference to Exhibit 3.3 of the Quarterly Report on Form 10-Q filed with the SEC on August 3, 2017. File No. 001-35211).
3.4	Amended and Restated Bylaws of Gastar Exploration Inc. dated November 4, 2015 (incorporated by reference to Exhibit 3.2 of the Quarterly Report on Form 10-Q filed with the SEC on November 5, 2015. File No. 001-35211).
3.5	Certificate of Elimination of Series C Junior Participating Preferred Stock of Gastar Exploration Inc. (incorporated by reference to Exhibit 3.1 of the Current Report on Form 8-K filed with the SEC on April 6, 2017. File No. 001-35211).
10.1	Amendment No. 2 to Third Amended and Restated Credit Agreement, dated as of August 2, 2017, among Gastar Exploration Inc., as borrower, certain subsidiaries of borrower, as guarantors, the lenders party thereto and Wilmington Trust, National Association, as administrative agent (incorporated by reference to Exhibit 10.7 of the Quarterly Report on Form 10-Q filed with the SEC on August 3, 2017. File No. 001-35211).
10.2	Amendment No. 3 to Third Amended and Restated Credit Agreement, executed on September 18, 2017, among Gastar Exploration Inc., as borrower, certain subsidiaries of borrower, as guarantors, the lenders party thereto and Wilmington Trust, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on September 19, 2017. File No. 001-35211).
10.3	Fourth Amendment to Amended and Restated Gastar Exploration Inc. Employee Change of Control Severance Plan, dated September 12, 2017 (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with SEC on September 13, 2017. 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

† 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.

SIGNAT URES

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: November 8, 2017	By:	/ s / J. RUSSELL PORTER **J. Russell Porter** **President and Chief Executive Officer** **(Duly authorized officer and principal executive officer)**
Date: November 8, 2017	By:	/ s / MICHAEL A. GERLICH **Michael A. Gerlich** **Senior Vice President and Chief Financial Officer** **(Duly authorized officer and principal financial and accounting officer)**

Exhibit 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER

PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A) OF THE SECURITIES EXCHANGE ACT OF 1934
PURSUANT TO SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, J. Russell Porter, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Gastar Exploration Inc. (the "Registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter (the Registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: November 8, 2017

/s/ J. RUSSELL PORTER
J. Russell Porter
Principal Executive Officer

Exhibit 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER

PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A) OF THE SECURITIES EXCHANGE ACT OF 1934
PURSUANT TO SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Michael A. Gerlich, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Gastar Exploration Inc. (the “Registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter (the Registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: November 8, 2017

/ s / MICHAEL A. GERLICH
Michael A. Gerlich
Principal Financial Officer

Exhibit 32.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER AND PRINCIPAL FINANCIAL OFFICER

PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, J. Russell Porter, Principal Executive Officer, and I, Michael A, Gerlich, Principal Financial Officer, of Gastar Exploration Inc. (the "Company"), hereby certify that the accompanying Quarterly Report on Form 10-Q for the period ended September 30, 2017 (the "Report"), filed by the Company with the Securities and Exchange Commission on the date hereof complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended.

I further certify that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: November 8, 2017

/ S / J. RUSSELL PORTER
J. Russell Porter
Principal Executive Officer

/ S / MICHAEL A. GERLICH
Michael A. Gerlich
Principal Financial Officer