MITCHAM INDUSTRIES INC
Form SC 13G/A
February 14, 2013

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

SCHEDULE 13G

Under the Securities Exchange Act of 1934

(Amendment No. 1)*

Mitcham Industries, Inc.

(Name of Issuer)

Common Stock

(Title of Class of Securities)

606501104

(CUSIP Number)

December 31, 2012

(Date of Event Which Requires Filing of this Statement)

Check the appropriate box to designate the rule pursuant to which this Schedule is filed:

[X] Rule 13d-1(b)

[ ] Rule 13d-1(c)

[ ] Rule 13d-1(d)

* The remainder of this cover page shall be filled out for a reporting person's initial filing on this form with respect to the subject class of securities, and for any subsequent amendment containing information which would alter the disclosures provided in a prior cover page.

The information required in the remainder of this cover page shall not be deemed to be "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934 (the "Act") or otherwise subject to the liabilities of that section of the Act, but shall be subject to all other provisions of the Act (however, see the Notes.)

CUSIP No. 606501104

1. NAMES OF REPORTING PERSONS
I.R.S. IDENTIFICATION NO. OF ABOVE PERSONS (ENTITIES ONLY)

Wellington Management Company, LLP
04-2683227

2. CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

(a) [ ]
(b) [ ]

3. SEC USE ONLY

4. CITIZENSHIP OR PLACE OF ORGANIZATION

Massachusetts

NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH	5. SOLE VOTING POWER	0
	6. SHARED VOTING POWER	990,070
	7. SOLE DISPOSITIVE POWER	0
	8. SHARED DISPOSITIVE POWER	1,375,148

9. AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON

1,375,148

10. CHECK IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES

[ ]

11. PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9)

10.71%

12. TYPE OF REPORTING PERSON

IA

Item 1.

(a) Name of Issuer
Mitcham Industries, Inc.

(b) Address of Issuer's Principal Executive Offices
8141 Highway 75 South
Huntsville, TX 77342

Item 2.

(a) Name of Person Filing
Wellington Management Company, LLP ("Wellington Management")

(b) Address of Principal Business Office or, if None, Residence
280 Congress Street
Boston, MA 02210

(c) Citizenship
Massachusetts

(d) Title of Class of Securities
Common Stock

(e) CUSIP Number
606501104

Item 3. If This Statement is Filed Pursuant to Rule 13d-1(b), or 13d-2(b) or (c), Check Whether the Person Filing is a:

(a) [ ] Broker or dealer registered under Section 15 of the Act (15 U.S.C. 78o).

(b) [ ] Bank as defined in Section 3(a)(6) of the Act (15 U.S.C. 78c).

(c) [ ] Insurance Company as defined in Section 3(a)(19) of the Act (15 U.S.C. 78c).

(d) [ ] Investment Company registered under Section 8 of the Investment Company Act of 1940 (15 U.S.C. 80a-8).

(e) [X] An investment adviser in accordance with Rule 240.13d-1(b)(1)(ii)(E);

(f) [ ] An employee benefit plan or endowment fund in accordance with Rule 240.13d-1(b)(1)(ii)(F);

(g) [ ] A parent holding company or control person in accordance with Rule 240.13d-1(b)(1)(ii)(G);

(h) [ ] A savings association as defined in Section 3(b) of the Federal Deposit Insurance Act (12 U.S.C. 1813);

(i) [ ] A church plan that is excluded from the definition of an investment company under Section 3(c)(14) of the Investment Company Act of 1940 (15 U.S.C. 80a-3);

(j) [ ] Group, in accordance with Rule 240.13d-1(b)(1)(ii)(J).

If this statement is filed pursuant to Rule 13d-1(c), check this box [ ]

Item 4. Ownership.

Provide the following information regarding the aggregate number and percentage of the class of securities of the issuer identified in Item 1.

(a) Amount Beneficially Owned:

Wellington Management, in its capacity as investment adviser, may be deemed to beneficially own 1,375,148 shares of the Issuer which are held of record by clients of Wellington Management.

(b) Percent of Class:

10.71%

(c) Number of shares as to which such person has:

(i)	sole power to vote or to direct the vote	0
(ii)	shared power to vote or to direct the vote	990,070
(iii)	sole power to dispose or to direct the disposition of	0
(iv)	shared power to dispose or to direct the disposition of	1,375,148

Item 5. Ownership of Five Percent or Less of Class.

If this statement is being filed to report the fact that as of the date hereof the reporting person has ceased to be the beneficial owner of more than five percent of the class of securities, check the following: [ ]

Item 6. Ownership of More than Five Percent on Behalf of Another Person.

The securities as to which this Schedule is filed by Wellington Management, in its capacity as investment adviser, are owned of record by clients of Wellington Management. Those clients have the right to receive, or the power to direct the receipt of, dividends from, or the proceeds from the sale of, such securities. No such client is known to have such right or power with respect to more than five percent of this class of securities, except as follows:

Wellington Trust Company, NA

Item 7. Identification and Classification of the Subsidiary Which Acquired the Security Being Reported on by the Parent Holding Company.

Not Applicable.

Item 8. Identification and Classification of Members of the Group.

Not Applicable.

Item 9. Notice of Dissolution of Group.

Not Applicable.

Item 10. Certification.

By signing below I certify that, to the best of my knowledge and belief, the securities referred to above were acquired and are held in the ordinary course of business and were not acquired and are not held for the purpose of or with the effect of changing or influencing the control of the issuer of the securities and were not acquired and are not held in connection with or as a participant in any transaction having that purpose or effect.

SIGNATURE

After reasonable inquiry and to the best of my knowledge and belief, I certify that the information set forth in this statement is true, complete and correct.

By: /s/ Steven M. Hoffman

Name: Steven M. Hoffman

Title: Vice President

Date: February 14, 2013

left:0pt;padding-Right:0.75pt;padding-Top:0.75pt;padding-Bottom:0pt;width:1%; border-bottom:solid 0.75pt #000000;white-space:nowrap;">

(6,793

)

813

(19,953

)

7,506

Balance at end of period

$

27,296

$

2,878

$

27,296

$

2,878

The amount of total gains (losses) for the period included in earnings attributable to the change in mark to market of commodity derivatives contracts still held at September 30, 2015 and 2014

$

4,511

$

7,623

$

986

$

(950

)

(1) Included in gain (loss) on commodity derivatives contracts on the condensed consolidated statements of operations.
At September 30, 2015, the estimated fair value of accounts receivable, prepaid expenses, accounts and revenue payables and accrued liabilities approximates their carrying value due to their short-term nature. The estimated fair value of the Company's long-term debt at September 30, 2015 was $269.3 million based on quoted market prices of the Notes (Level 1) and the respective carrying value of the Revolving Credit Facility because the interest rate approximates the current market rate (Level 2).

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

The fair value guidance, as amended, establishes that every derivative instrument is to be recorded on the balance sheet as either an asset or liability measured at fair value. See Note 6, "Derivative Instruments and Hedging Activity."

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, 2015 and 2014, the Company reported gains of $4.5 million and $7.6 million, respectively, in the condensed consolidated statements of operations related to the change in the fair value of its commodity derivative contracts still held at September 30, 2015 and 2014. For the nine months ended September 30, 2015 and 2014, the Company reported a gain of $1.0 million and a loss of $1.0 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, 2015 and 2014.

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

Settlement Period	Derivative Instrument	Average Daily Volume(1) (in Bbls)	Total of Notional Volume	Floor (Long)	Short Put	Ceiling (Short)
2015	Costless three-way collar	400	48,800	$85.00	$70.00	$96.50
2015	Costless three-way collar	312	38,100	$85.00	$65.00	$97.80
2015	Costless three-way collar	50	6,100	$85.00	$65.00	$96.25
2015	Costless collar	750	91,500	$52.50	$—	$62.05
2015	Costless collar	300	36,600	$52.50	$—	$68.10
2015	Costless collar	700	85,400	$45.00	$—	$55.25
2015	Fixed price swap	600	73,200	$72.54	$—	$—
2015	Fixed price swap	250	30,500	$74.20	$—	$—
2016	Costless three-way collar	275	100,600	$85.00	$65.00	$95.10
2016	Costless three-way collar	330	120,780	$80.00	$65.00	$97.35
2016	Costless three-way collar	450	164,700	$57.50	$42.50	$80.00
2016	Put spread	550	201,300	$85.00	$65.00	$—
2016	Put spread	300	109,800	$85.50	$65.50	$—
2017	Costless three-way collar	280	102,200	$80.00	$65.00	$97.25
2017	Costless three-way collar	242	88,150	$80.00	$60.00	$98.70
2017	Costless three-way collar	200	73,000	$60.00	$42.50	$85.00
2017	Put spread	500	182,500	$82.00	$62.00	$—
2017	Costless three-way collar	200	73,000	$57.50	$42.50	$76.13
2018(2)	Put spread	425	103,275	$80.00	$60.00	$—

(1) Crude volumes hedged include oil, condensate and certain components of our NGLs production.
(2) For the period January to August 2018.

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As of September 30, 2015, 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 (in MMBtus)	Total of Notional Volume	Base Fixed Price	Floor (Long)	Short Put	Call (Long)	Ceiling (Short)
2015	Fixed price swap	400	48,800	$4.00	$ —	$—	$ —	$ —
2015	Fixed price swap	2,500	305,000	$4.06	$ —	$—	$ —	$ —
2015	Protective spread	2,600	317,200	$4.00	$ —	$3.25	$ —	$ —
2015	Fixed price swap	5,000	610,000	$3.49	$ —	$—	$ —	$ —
2015	Fixed price swap	2,000	244,000	$3.53	$ —	$—	$ —	$ —
2015	Producer three-way collar	2,500	305,000	$—	$ 3.70	$3.00	$ —	$ 4.09
2015	Producer three-way collar	5,000	610,000	$—	$ 3.77	$3.00	$ —	$ 4.11
2015[1]	Producer three-way collar	2,000	122,000	$—	$ 3.00	$2.25	$ —	$ 3.34
2015[1]	Fixed price swap	10,000	610,000	$2.94	$ —	$—	$ —	$ —
2015[2]	Producer three-way collar	2,500	152,500	$—	$ 3.00	$2.25	$ —	$ 3.65
2015	Basis swap[3]	2,500	305,000	$(1.12)	$ —	$—	$ —	$ —
2015	Basis swap[3]	2,500	305,000	$(1.11)	$ —	$—	$ —	$ —
2015	Basis swap[3]	2,500	305,000	$(1.14)	$ —	$—	$ —	$ —
2016[4]	Producer three-way collar	2,500	762,500	$—	$ 3.00	$2.25	$ —	$ 3.65
2016	Protective spread	2,000	732,000	$4.11	$ —	$3.25	$ —	$ —
2016	Producer three-way collar	2,000	732,000	$—	$ 4.00	$3.25	$ —	$ 4.58
2016	Producer three-way collar	5,000	1,830,000	$—	$ 3.40	$2.65	$ —	$ 4.10
2016	Basis swap[5]	2,500	915,000	$(1.10)	$ —	$—	$ —	$ —
2016	Basis swap[5]	2,500	915,000	$(1.02)	$ —	$—	$ —	$ —
2016	Basis swap[5]	2,500	915,000	$(1.00)	$ —	$—	$ —	$ —
2016[6]	Producer three-way collar	7,500	682,500	$—	$ 3.00	$2.50	$ —	$ 4.00
2016[7]	Producer three-way collar	5,000	1,375,000	$—	$ 3.00	$2.35	$ —	$ 4.00
2017	Short call	10,000	3,650,000	$—	$ —	$—	$ —	$ 4.75
2017	Basis swap[5]	2,500	912,500	$(1.02)	$ —	$—	$ —	$ —
2017	Basis swap[5]	2,500	912,500	$(1.00)	$ —	$—	$ —	$ —
2017	Producer three-way collar	5,000	1,825,000	$—	$ 3.00	$2.35	$ —	$ 4.00
2018	Basis swap[5]	2,500	912,500	$(1.02)	$ —	$—	$ —	$ —
2018	Basis swap[5]	2,500	912,500	$(1.00)	$ —	$—	$ —	$ —
2018	Producer three-way collar	5,000	1,825,000	$—	$ 3.00	$2.35	$ —	$ 4.00

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

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

Settlement Period	Derivative Instrument	Average Daily Volume (in Bbls)	Total of Notional Volume	Base Fixed Price
2015	Fixed price swap	250	30,500	$45.61
2015	Fixed price swap	500	61,000	$20.79
2016	Fixed price swap	500	183,000	$20.79

As of September 30, 2015, all of the Company's economic derivative hedge positions were with a multinational energy company or large financial institutions, which are not known to the Company to be in default on their derivative positions. The Company is exposed to credit risk to the extent of non-performance by the counterparties in the derivative contracts discussed above;

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however, the Company does not anticipate non-performance by such counterparties. None of the Company's derivative instruments contain credit-risk related contingent features.

In conjunction with certain derivative hedging activity, the Company deferred the payment of certain put premiums for the production month period October 2015 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 liabilities as they become payable. The following table provides information regarding the deferred put premium liabilities for the periods indicated:

	September 30, 2015	December 31, 2014
	(in thousands)	
Current commodity derivative put premium payable	$2,393	$ 2,481
Long-term commodity derivative put premium payable	3,588	4,702
Total unamortized put premium liabilities	$5,981	$ 7,183

	For the Three Months Ended September 30, 2015	For the Nine Months Ended September 30, 2015
	(in thousands)	
Put premium liabilities, beginning balance	$5,566	$ 7,183
Amortization of put premium liabilities	—	(2,297)
Additional put premium liabilities	415	1,095
Put premium liabilities, ending balance	$5,981	$ 5,981

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

	Amortization (in thousands)
January to December 2016	$ 3,194
January to December 2017	1,819
January to August 2018	968
Total unamortized put premium liabilities	$ 5,981

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, 2015	December 31, 2014
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Current assets	$16,895	$ 19,687
Commodity derivative contracts	Other assets	10,710	7,815
Commodity derivative contracts	Long-term liabilities	(309)	—
Total derivatives not designated as hedging instruments		$27,296	$ 27,502

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	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives For the Three Months Ended September 30, 2015	2014
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Gain on commodity derivatives contracts	$11,301	$6,663
Total		$11,301	$6,663

	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, 2015	2014
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Gain (loss) on commodity derivatives contracts	$19,734	$(8,761)
Total		$19,734	$(8,761)

7. Capital Stock
Common Stock

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

Preferred Stock

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

Series A Preferred Stock

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

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

The Series A Preferred Stock cannot be converted into common stock, but may be redeemed, at the Company’s option for $25.00 per share plus any accrued and unpaid dividends.

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

The Company pays cumulative dividends on the Series A Preferred Stock at a fixed rate of 8.625% per annum of the $25.00 per share liquidation preference. For the three and nine months ended September 30, 2015, the Company recognized dividend expense of $2.2 million and $6.5 million, respectively, for the Series A Preferred Stock.

Series B Preferred Stock

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

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

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

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

The Company pays cumulative dividends on the Series B Preferred Stock at a fixed rate of 10.75% per annum of the $25.00 per share liquidation preference. For the three and nine months ended September 30, 2015, the Company recognized dividend expense of $1.4 million and $4.3 million, respectively, for the Series B Preferred Stock.

Other Share Issuances

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

	For the Three Months Ended September 30, 2015	For the Nine Months Ended September 30, 2015
Other share issuances:		
Shares of restricted common stock granted	5,380	1,426,604
Shares of restricted common stock vested	31,282	1,306,154
Shares of common stock issued pursuant to PBUs vested,	—	497,636

net of forfeitures		
Shares of restricted common stock surrendered upon vesting/exercise[1]	3,167	385,405
Shares of restricted common stock forfeited	—	24,498

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

On June 12, 2014, the Company's stockholders approved an amendment and restatement to the Gastar Exploration Inc. Long-Term Incentive Plan (the "LTIP"), effective April 24, 2014, to, among other things, increase the number of shares of common stock reserved for issuance under the LTIP by 3,000,000 shares of common stock. There were 2,848,062 shares of common stock available for issuance under the LTIP at September 30, 2015.

Shares Reserved

At September 30, 2015, the Company had 866,600 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, 2015	2014	For the Nine Months Ended September 30, 2015	2014
	(in thousands)			
Interest expense:				
Cash and accrued	$7,703	$7,297	$22,872	$21,639
Amortization of deferred financing costs(1)	916	779	2,652	2,270
Capitalized interest	(686)	(1,085)	(3,094)	(3,115)
Total interest expense	$7,933	$6,991	$22,430	$20,794

(1) The three months ended September 30, 2015 and 2014 includes $644,000 and $584,000, respectively, of debt discount accretion related to the Notes. The nine months ended September 30, 2015 and 2014 includes $1.9 million and $1.7 million, respectively, of debt discount accretion related to the Notes.

9. Income Taxes

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

10. Earnings per Share

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

	For the Three Months Ended September 30,	For the Nine Months Ended September 30,

	2015	2014	2015	2014
	(in thousands, except per share and share data)			
Net (loss) income attributable to common stockholders	$(191,819)	$9,807	$(312,837)	$9,858
Weighted average common shares outstanding - basic	77,628,120	60,006,903	77,453,251	58,982,709
Incremental shares from unvested restricted shares	—	2,614,215	—	2,587,345
Incremental shares from outstanding stock options	—	115,421	—	109,755
Incremental shares from outstanding PBUs	—	662,907	—	626,671
Weighted average common shares outstanding - diluted	77,628,120	63,399,446	77,453,251	62,306,480
Net (loss) income per share of common stock attributable to common stockholders:				
Basic	$(2.47)	$0.16	$(4.04)	$0.17
Diluted	$(2.47)	$0.15	$(4.04)	$0.16
Common shares excluded from denominator as anti-dilutive:				
Unvested restricted shares	239,161	14,877	146,253	45,203
Stock options	—	—	—	—
Unvested PBUs	503,271	—	84,179	—
Total	742,432	14,877	230,432	45,203

11. Commitments and Contingencies
Litigation

Gastar Exploration Ltd vs. U.S. Specialty Ins. Co. and Axis Ins. Co. (Cause No.2010-11236) District Court of Harris County, Texas 190th Judicial District. On February 19, 2010, the Company filed a lawsuit claiming that the Company was due reimbursement of qualifying claims related to the settlement and associated legal defense costs under the Company's directors and officers liability insurance policies related to the ClassicStar Mare Lease Litigation settled on December 17, 2010 for $21.2 million. The combined coverage limits under the directors and officers liability coverage is $20.0 million. The District Court granted the underwriters' summary judgment request by a ruling dated January 4, 2012. The Company appealed the District Court ruling and on July 15, 2013, the Fourteenth Court of Appeals of Texas reversed the summary judgment ruling granted against the Company on the basis of the policies' prior-and-pending litigation endorsement and remanded the case for further proceedings in the District Court. The insurers filed a motion for reconsideration in the Fourteenth Court of Appeals, which that court denied. The insurers then sought discretionary review from the Texas Supreme Court, which that court denied on February 27, 2015. The insurers then filed in the Texas Supreme Court a motion for rehearing of their denied petition for review, which the court has denied. The case has now been remanded to the District Court. The District Court proceedings will include, but not be limited to, a determination of the portion of the Company's settlement of the ClassicStar Mare Lease Litigation that is covered by the insuring agreements. On July 28, 2015, the parties submitted briefs in support of their respective positions regarding the issues left to be resolved in the case and the requisite amount of time for such proceedings. On August 11, 2015, the court entered a docket control order establishing the week of March 7, 2016 as the tentative week for the case to go to trial. The court has since canceled that trial date to allow additional time to brief discovery- and coverage-related issues.

Husky Ventures, Inc. vs. J. Russell Porter, Michael A. Gerlich, Michael McCown, Keith R. Blair, Henry J. Hansen and John M. Selser Sr. (Case No. CIV-15-637-R) United States District Court for the Western District of Oklahoma. On June 9, 2015, Husky Ventures, Inc. (“Husky”) filed this action against five of the Company’s senior officers and our non-executive chairman of the board alleging that each of the defendants committed fraud by grossly understating the costs of certain oil and gas interests the Company acquired that were outside a Mid-Continent AMI between Husky and the Company while inflating the costs of interests simultaneously acquired within the AMI. Husky alleges this resulted in the defendants improperly shifting a disproportionate amount of acquisition costs away from the Company and to Husky. Husky sought to recover actual damages alleged to be in excess of $2.0 million, as well as punitive damages and attorneys’ fees. In connection with the Company’s entry into the Purchase Agreement (defined above), the Company, five of its senior officers, its non-executive chairman and Husky agreed to the settlement and mutual release of claims that the Company and Husky made against each other in this matter as well as any claims the parties may have had against each other in connection with the AMI participation agreements. In the event that the Purchase Agreement is terminated pursuant to its terms prior to the consummation of the transactions contemplated thereby, the settlement and release will be rescinded.

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.

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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,	
	2015	2014
	(in thousands)	
Cash paid for interest, net of capitalized amounts	$12,699	$11,668
Non-cash transactions:		
Capital expenditures (excluded from) included in accounts payable and accrued drilling costs	$(12,396)	$1,601
Capital expenditures included in accounts receivable	$—	$4,077
Asset retirement obligation included in oil and natural gas properties	$276	$109
Application of advances to operators	$11,113	$36,812
Expenses accrued for the issuance of common stock	$—	$223
Other	$—	$(11)

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

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

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

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

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

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- 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 I, Item 1A. “Risk Factors” and elsewhere in our 2014 Form 10-K, (iii) our subsequent reports and registration statements filed from time to time with the SEC and (iv) other announcements we make from time to time.

You should not unduly rely on these forward-looking statements in this report, as they speak only as of the date of this report. Except as required by law, we undertake no obligation to publicly update, revise or release any revisions to these forward-looking statements after the date on which they are made to reflect new information, events or circumstances occurring after the date of this report or to reflect the occurrence of unanticipated events.

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

Overview

We are an independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and NGLs in the U.S. Our principal business activities include the identification, acquisition, and subsequent exploration and development of oil and natural gas properties with an emphasis on unconventional reserves, such as shale resource plays. In Oklahoma, we are developing the primarily oil-bearing reservoirs of the Hunton Limestone horizontal oil play and is testing other prospective formations on the same acreage, including the Meramec Shale (middle Mississippi Lime) and the Woodford Shale, which is commonly referred to as the STACK Play, and emerging prospective plays in the shallow Oswego formation and in the Osage formation, a deeper bench of the Mississippi Lime located below the Meramec. In West Virginia, we have developed liquids-rich natural gas in the Marcellus Shale and have drilled and completed two successful dry gas Utica Shale/Point Pleasant wells on our acreage. We have engaged a third-party to market certain Marcellus Shale and Utica/Point Pleasant acreage, primarily located in Marshall and Wetzel Counties, West Virginia, including producing wells.

Our current operational activities are conducted in, and our consolidated revenues are generated from, markets exclusively in the U.S. As of September 30, 2015, our major assets consist of approximately 212,200 gross (105,700 net) acres in Oklahoma and approximately 55,800 gross (37,400 net) acres in the Marcellus Shale in West Virginia and southwestern Pennsylvania, of which approximately 22,800 gross (8,800 net) acres have Utica Shale/Point Pleasant potential. Subsequent to September 30, 2015 and as a result of the October 14, 2015 acquisition of approximately 15,700 net acres in Kingfisher and Garfield Counties, Oklahoma and the conveyance of approximately 11,000 net acres in Blaine and Major Counties, Oklahoma to the sellers, our Mid-Continent assets will consist of approximately 212,200 gross (110,400 net) acres in Oklahoma.

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

Oil and Natural Gas Activities

The following provides an overview of our major oil and natural gas projects. While actively pursuing specific exploration and development activities in 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. We also continue to concentrate our drilling activities in the Mid-Continent and are marketing certain Marcellus Shale and Utica/Point Pleasant acreage, primarily in Marshall and Wetzel Counties, West Virginia, including producing wells, in light of the substantial downturn in oil, natural gas and NGLs prices that has occurred since November 2014. The dramatic pricing downturns that we are experiencing may cause us to make further changes in our drilling plans.

Mid-Continent Horizontal Oil Play.

The Hunton Limestone is a limestone formation stretching over approximately 2.7 million acres mainly in Oklahoma, but also in the neighboring states of Texas, New Mexico and Arkansas. Hunton Limestone development has been attractive due to the high quality oil production and the associated production of high BTU content natural gas in the area. In addition to Hunton Limestone potential, we believe that our acreage is also prospective in the STACK play, an area of southeastern Oklahoma that includes oil and gas-rich shale formations such as the proven Meramec and Woodford Shale, ranging in depth from 8,000 to 11,000 feet, and emerging prospective plays in the shallow Oswego formation and in the Osage formation, a deeper bench of the Mississippi Lime located below the Meramec. At

September 30, 2015, we held leases covering approximately 212,200 gross (105,700 net) acres in Major, Garfield, Canadian, Kingfisher, Logan, Blaine and Oklahoma Counties, Oklahoma within the Hunton Limestone horizontal oil play.

On October 14, 2015, we entered into a definitive purchase and sale agreement (the “Purchase Agreement”) to acquire additional working and net revenue interests in 103 gross (10.2 net) producing wells and certain undeveloped acreage in the STACK and Hunton Limestone formations in our AMI from our AMI co-participant for approximately $43.3 million and the conveyance of approximately 11,000 net non-core, non-producing acres in Blaine, Major and Kingfisher Counties, Oklahoma to the sellers, subject to certain adjustments and customary closing conditions. The transaction is expected to close on or about November 30, 2015 with an effective date of July 1, 2015. In connection with the acquisition, the AMI participation agreements with our AMI co-participant will be dissolved.

On July 6, 2015, we sold to an undisclosed private third party certain non-core assets comprised of 38 gross (16.7 net) wells producing approximately net 170 Boe/d (41% oil) for the three months ended March 31, 2015 and approximately 29,500 gross (19,200 net) acres in Kingfisher County, Oklahoma for approximately $45.9 million, net of customary closing adjustments. The sale is reflected as a reduction to the full cost pool and we did not record a gain or loss related to the divestiture as it was not significant to the full cost pool.

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

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

				Cumulative Production Averages[2]			
	Current	Approximate	Peak				Approximate Gross
	Working	Lateral Length	Production			Date of First	Costs to Drill &
Well Name	Interest	(in feet)	Rates[1] (Boe/d)	Boe/d	% Oil	Production or Status	Complete ($ millions)
LB 1-1H	47.6%	4,300	791	181	62%	January 23, 2015	$ 5.2
Hubbard 1-23H[3]	57.0%	4,500	63	19	96%	February 19, 2015	$ 6.1
Boss Hogg 1-14H	50.0%	4,300	129	51	70%	February 21, 2015	$ 7.4
Bo 1-23H	43.8%	4,300	547	250	44%	February 28, 2015	$ 5.0
The River 1-22H	39.7%	3,800	1,250	787	28%	March 14, 2015	$ 4.6
Bigfoot 1-9H	47.4%	4,200	161	88	56%	March 17, 2015	$ 5.1
Falcon 1-5H	51.5%	4,100	1,202	557	71%	April 1, 2015	$ 4.4
Dorothy 1-12H	49.5%	3,900	41	15	74%	April 10, 2015	$ 4.5
Polar Bear 1-20H	47.4%	4,300	403	115	87%	May 5, 2015	$ 4.9
Unruh 1-34H[4]	75.4%	4,400	N/A	N/A	N/A	Commenced flowback	$ 7.6

(1) Represents highest daily gross Boe rate.
(2) Represents gross cumulative production divided by actual producing days through November 1, 2015.
(3) After payout working interest is 49.9%.
(4)

Approximate gross costs to drill and complete includes costs to re-drill the well due to an initial horizontal casing collapse.

In connection with our entry into the Purchase Agreement, Gastar, five of its senior officers, its non-executive chairman and our AMI co-participant agreed to the settlement and mutual release of claims that Gastar and our AMI co-participant made against each other in separate lawsuits pending in federal court in Oklahoma as well as any claims the parties may have had against each other in connection with the participation agreements. In the event that the Purchase Agreement is terminated pursuant to its terms prior to the consummation of the transactions contemplated thereby, the settlement and release will be rescinded, as described in Part I, Item 1. “Financial Statements, Note 11 - Commitments and Contingencies” of this report.

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

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Peak Production Rates[1] (BOE/d)	Cumulative Production Averages[2] BOE/d	Cumulative Production Averages[2] % Oil	Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
Upper Hunton Completions							
Warsaw 33-2H	98.3%	4,900	615	210	55%	February 13, 2015	$ 4.4
Blair Farms 31-1H	98.3%	7,500	509	361	78%	May 7, 2015	$ 5.0
Easton 22-4H	98.3%	5,800	604	298	90%	May 20, 2015	$ 2.7
Jetson 8-2H	98.3%	6,100	353	208	87%	August 19, 2015	$ 4.2
Arcadia Farms 15-2H	98.3%	7,700	N/A	267	88%	September 13, 2015	$ 3.1
O' Donnell 5-1H	98.3%	4,400	N/A	119	96%	October 8, 2015	$ 4.5
Lower Hunton Completions							
Warsaw 33-3H	98.3%	6,100	663	203	59%	February 14, 2015	$ 6.9
Easton 22-3H	98.3%	6,700	548	390	79%	May 24, 2015	$ 4.9
Davis 9-2H	98.3%	6,600	N/A	200	83%	August 6, 2015	$ 5.8
Jetson 8-1H	98.3%	5,800	N/A	154	67%	August 19, 2015	$ 5.1
Davis 9-4H	98.3%	7,700	N/A	101	100%	October 3, 2015	$ 5.3
Arcadia Farms 15-1CH	98.3%	6,800	N/A	192	76%	October 9, 2015	$ 5.7
O'Donnell 5-2CH	98.3%	5,600	N/A	176	73%	October 9, 2015	$ 5.6

(1) Represents highest daily gross Boe rate.
(2) Represents gross cumulative production divided by actual producing days through November 1, 2015.

We are continuing to monitor well flow back results on recently drilled and completed wells and remain encouraged by the overall well results to date. As a result of the current commodity price environment, we currently have no plans to drill any new Hunton Limeston wells during the remainder of 2015.

On September 6, 2015, we spudded our first Meramec well, the Deep River 30-1H, with a vertical depth of approximately 7,300 feet and drilled an approximate 5,100-foot lateral and completed it with a 34-stage fracture stimulation. The Deep River 30-1H was placed on flowback on October 28, 2015. Our working interest in the Deep River 30-1H is 100% (NRI 80%). The estimated cost to drill and complete the Deep River 30-1H is approximately $5.8 million.

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

Mid-Continent	For the Three Months Ended September 30, 2015	2014	For the Nine Months Ended September 30, 2015	2014
Net Production:				
Oil and condensate (MBbl)	274	213	875	516
Natural gas (MMcf)	805	715	2,491	2,004
NGLs (MBbl)	111	83	320	232
Total net production (MBoe)	520	415	1,611	1,082
Net Daily Production:				
Oil and condensate (MBbl/d)	3.0	2.3	3.2	1.9
Natural gas (MMcf/d)	8.7	7.8	9.1	7.3
NGLs (MBbl/d)	1.2	0.9	1.2	0.9
Total net daily production (MBoe/d)	5.6	4.5	5.9	4.0
Average sales price per unit(1):				
Oil and condensate (per Bbl)	$44.45	$96.09	$48.54	$98.45
Natural gas (per Mcf)	$2.67	$3.87	$2.76	$4.46
NGLs (per Bbl)	$10.28	$30.42	$13.16	$34.83
Average sales price per Boe(1)	$29.80	$62.11	$33.27	$62.66
Selected operating expenses (in thousands):				
Production taxes	$329	$904	$1,170	$2,264
Lease operating expenses(2)	$4,328	$3,160	$15,020	$9,793
Transportation, treating and gathering	$3	$9	$10	$31
Selected operating expenses per Boe:				
Production taxes	$0.63	$2.18	$0.73	$2.09
Lease operating expenses(2)	$8.33	$7.62	$9.32	$9.05
Transportation, treating and gathering	$0.01	$0.02	$0.01	$0.03
Production costs(3)	$8.34	$7.64	$9.33	$9.08

(1) Excludes the impact of hedging activities.

(2) Lease operating expenses for the three and nine months ended September 30, 2015 include $1.1 million and $3.8 million, respectively, of workover expense for one-time production enhancing workovers completed on certain WEHLU wells. Excluding workover expense, lease operating expense per Boe for the three and nine months ended September 30, 2015 would have been $6.23 per Boe and $6.94 per Boe, respectively, compared to $7.70 per Boe and $9.04 per Boe for the three and nine months ended September 30, 2014, respectively.

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

Appalachian Basin.

Marcellus Shale. The Marcellus Shale is Devonian aged shale that underlies much of the Appalachian region of Pennsylvania, New York, Ohio, West Virginia and adjacent states. The depth of the Marcellus Shale and its low permeability make the Marcellus Shale an unconventional exploration target in the Appalachian Basin. Advancements in horizontal drilling and stimulation have produced promising results in the Marcellus Shale. These developments have resulted in increased leasing and drilling activity in the area. As of September 30, 2015, our acreage position in the play was approximately 55,800 gross (37,400 net) acres. We refer to the approximately 26,700 gross (11,600 net) acres reflecting our interest in our Marcellus Shale assets in West Virginia and Pennsylvania subject to the Atinum Participation Agreement described below as our Marcellus West acreage. We refer to the approximately 29,100 gross (25,900 net) acres in Preston, Tucker, Pocahontas, Randolph and Pendleton Counties, West Virginia as our Marcellus East acreage. The entirety of our acreage is believed to be in the core, over-pressured area of the Marcellus play. We continue to opportunistically swap acreage with adjacent operators in order to optimize our acreage and maximize horizontal lateral lengths.

Due to the current price environment in the Appalachian Basin, we have suspended our drilling operations in the Appalachian Basin until product prices improve. As of September 30, 2015, we had no drilling operations in progress on our Marcellus Shale acreage in Marshall County, West Virginia. We have engaged a third-party to market certain Marcellus Shale and Utica Shale/Point Pleasant acreage, primarily located in Marshall and Wetzel Counties, West Virginia, including producing wells.

On September 21, 2010, we entered into the Atinum Participation Agreement pursuant to which we ultimately assigned to Atinum, for $70.0 million in total consideration, a 50% working interest in certain undeveloped acreage and shallow producing wells.

Atinum has the right to participate in any future leasehold acquisitions made by us within Ohio, New York, Pennsylvania and West Virginia, excluding the counties of Pendleton, Pocahontas, Preston, Randolph and Tucker, West Virginia, on terms identical to those governing the then-existing Atinum Participation Agreement. We are the operator and are obligated to offer any future lease acquisitions to Atinum on a 50/50 basis. Atinum will pay us on an annual basis an amount equal to 10% of lease bonuses and third party leasing costs, up to $20.0 million, and 5% of such costs on activities above $20.0 million.

The Atinum co-participants pursued an initial three-year development program that called for the drilling of a minimum of 60 operated horizontal wells by year-end 2013. Due to natural gas price declines, we and Atinum agreed to reduce the minimum wells to be drilled requirements from 60 gross wells to 51 gross wells. At September 30, 2015, 74 gross (37.0 net) operated Marcellus Shale horizontal wells were capable of production. All of our Marcellus Shale well operations to date were drilled under the Atinum Participation Agreement. The Atinum Participation Agreement expired on November 1, 2015 and discussions are currently in progress regarding its replacement.

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

Marcellus Shale	For the Three Months Ended September 30, 2015	2014	For the Nine Months Ended September 30, 2015	2014
Net Production:				
Oil and condensate (MBbl)	56	37	191	144
Natural gas (MMcf)	1,987	1,925	6,215	6,387
NGLs (MBbl)	226	97	533	311
Total net production (MBoe)	613	455	1,760	1,519
Net Daily Production:				
Oil and condensate (MBbl/d)	0.6	0.4	0.7	0.5
Natural gas (MMcf/d)	21.6	20.9	22.8	23.4
NGLs (MBbl/d)	2.5	1.1	2.0	1.1
Total net daily production (MBoe/d)	6.7	4.9	6.4	5.6
Average sales price per unit (1)(2):				
Oil and condensate (per Bbl)	$11.64	$62.57	$17.24	$77.28
Natural gas (per Mcf)	$0.46	$2.14	$0.95	$4.84
NGLs (per Bbl)	$(1.56)	$26.98	$1.60	$27.68
Average sales price per Boe (1)(2)	$1.97	$19.87	$5.70	$33.35
Selected operating expenses (in thousands):				
Production taxes(3)	$271	$627	$988	$3,198
Lease operating expenses(3)	$860	$967	$3,399	$3,256
Transportation, treating and gathering(3)	$552	$361	$1,462	$3,109
Selected operating expenses per Boe:				
Production taxes(3)	$0.44	$1.38	$0.56	$2.10
Lease operating expenses(3)	$1.40	$2.13	$1.93	$2.14
Transportation, treating and gathering(3)	$0.90	$0.79	$0.83	$2.05
Production costs(4)	$1.76	$2.53	$2.15	$3.79

(1) Excludes the impact of hedging activities.

(2) The nine months ended September 30, 2014 includes the benefit of a one-time revenue adjustment related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, average sales prices would have been as follows:

	For the Nine Months Ended September 30, 2014
Marcellus Shale	
Average sales price per unit:	
Oil and condensate (per Bbl)	$ 55.42
Natural gas (per Mcf)	$ 3.57
NGLs (per Bbl)	$ 29.86
Average sales price per Boe	$ 26.37

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

	For the Nine Months Ended September 30, 2014
Marcellus Shale	
Selected operating expenses per Boe:	
Production taxes	$ 1.72
Lease operating expenses	$ 2.27
Transportation, treating and gathering	$ 1.00

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

	For the Nine Months Ended September 30, 2014
Marcellus Shale	
Selected operating expenses per Boe:	
Production costs	$ 2.87

Utica Shale/Point Pleasant. The Utica Shale is Ordovician aged shale that underlies much of the Appalachian region of Pennsylvania, Ohio and West Virginia. The depth of the Utica Shale and its low permeability make it an unconventional exploration target in the Appalachian Basin. Advancements in horizontal drilling and hydraulic fracture stimulation have produced promising results in the Utica Shale, some in close proximity to our existing Marcellus West acreage. Based on our successful completion of two Utica Shale wells, log analysis of offsetting wells and recent Utica Shale completions by other nearby operators, we believe that our Marcellus West acreage should be prospective for high-pressure, high-deliverability dry natural gas development in the Utica Shale/Point Pleasant formation. We drilled the Simms U-5H to a total vertical depth of 11,500 feet and drilled an approximate 4,400-foot lateral and completed it with a 25-stage fracture stimulation. The Simms U-5H was producing at a most recent five-day average rate of 3.8 MMcf/d of natural gas and had total cumulative production of 3.5 Bcf as of October 25, 2015. Our working interest in the Simms U-5H is 50.0% (43.2% net revenue interest). We drilled the Blake U-7H to a total vertical depth of 11,100 feet and drilled an approximate 6,600-foot lateral and completed it with a 34-stage fracture stimulation. The Blake U-7H was producing at a most recent five-day average rate of 8.8 MMcf/d of natural gas and had total cumulative production of 2.2 Bcf as of October 25, 2015. Our working interest in the Blake U-7H is 50.0% (41.1% net revenue interest). The estimated cost to drill and complete the Blake U-7H was approximately $15.9 million. All of our Utica Shale/Point Pleasant well operations to date were drilled under the Atinum Participation Agreement. The Atinum Participation Agreement expired on November 1, 2015, and discussions are currently in progress regarding its replacement. We have engaged a third-party to market certain of our Marcellus Shale and Utica Shale/Point Pleasant acreage, primarily located in Marshall and Wetzel Counties, West Virginia, including producing wells.

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

Utica Shale	For the Three Months Ended September 30, 2015	2014	For the Nine Months Ended September 30, 2015	2014
Net Production:				
Natural gas (MMcf)	698	187	1,653	187
Total net production (MBoe)	116	31	276	31
Net Daily Production:				
Natural gas (MMcf/d)	7.6	2.0	6.1	0.7
Total net daily production (MBoe/d)	1.3	0.3	1.0	0.1
Average sales price per unit (1):				
Natural gas (per Mcf)	$0.57	$1.44	$0.81	$1.44
Average sales price per Boe (1)	$3.39	$8.64	$4.86	$8.64
Selected operating expenses (in thousands):				
Production taxes	$55	$28	$159	$28
Lease operating expenses	$24	$8	$56	$8
Transportation, treating and gathering	$60	$27	$184	$27
Selected operating expenses per Boe:				
Production taxes	$0.47	$0.89	$0.58	$0.89
Lease operating expenses	$0.21	$0.27	$0.20	$0.27
Transportation, treating and gathering	$0.52	$0.88	$0.67	$0.88
Production costs (2)	$0.73	$1.15	$0.87	$1.15

(1) Excludes the impact of hedging activities.
(2) Production costs include lease operating expenses, insurance, gathering and workover expense and excludes ad valorem and severance taxes.

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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 and natural gas and operating expenses for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands, except per unit amounts)			
Net Production:				
Oil and condensate (MBbl)	330	250	1,066	660
Natural gas (MMcf)	3,490	2,826	10,360	8,579
NGLs (MBbl)	338	180	854	543
Total net production (MBoe)	1,249	901	3,646	2,633
Net Daily production:				
Oil and condensate (MBbl/d)	3.6	2.7	3.9	2.4
Natural gas (MMcf/d)	37.9	30.7	37.9	31.4
NGLs (MBbl/d)	3.7	2.0	3.1	2.0
Total net daily production (MBoe/d)	13.6	9.8	13.4	9.6
Average sales price per unit[1]:				
Oil and condensate per Bbl, excluding impact of hedging activities	$38.89	$91.17	$42.94	$93.83
Oil and condensate per Bbl, including impact of hedging activities [2]	$44.84	$88.77	$48.30	$90.24
Natural gas per Mcf, excluding impact of hedging activities	$0.99	$2.53	$1.36	$4.68
Natural gas per Mcf, including impact of hedging activities [2]	$1.57	$2.56	$1.93	$4.29
NGLs per Bbl, excluding impact of hedging activities	$2.35	$28.56	$5.94	$30.74
NGLs per Bbl, including impact of hedging activities [2]	$10.64	$26.13	$14.32	$26.85
Average sales price per Boe, excluding impact of hedging activities	$13.68	$38.94	$17.81	$45.10
Average sales price per Boe, including impact of hedging activities [2]	$19.11	$37.87	$22.95	$42.13
Selected operating expenses:				
Production taxes[3]	$655	$1,558	$2,317	$5,489

Lease operating expenses[3]	$5,214	$4,136	$18,475	$13,057
Transportation, treating and gathering[3]	$615	$397	$1,654	$3,168
Depreciation, depletion and amortization	$15,394	$11,111	$45,945	$33,773
Impairment of natural gas and oil properties	$181,966	$—	$282,118	$—
General and administrative expense	$4,683	$4,002	$13,352	$12,658
Selected operating expenses per Boe:				
Production taxes[3]	$0.52	$1.73	$0.64	$2.09
Lease operating expenses[3][4]	$4.17	$4.59	$5.07	$4.96
Transportation, treating and gathering[3]	$0.49	$0.44	$0.45	$1.20
Depreciation, depletion and amortization	$12.32	$12.33	$12.60	$12.83
General and administrative expense	$3.75	$4.44	$3.66	$4.81
Production costs[5]	$4.40	$4.84	$5.22	$5.93

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

	For the Nine Months Ended September 30, 2014
Average sales price per unit:	
Oil and condensate per Bbl, excluding impact of hedging activities	$ 89.06
Oil and condensate per Bbl, including impact of hedging activities (2)	$ 85.47
Natural gas per Mcf, excluding impact of hedging activities	$ 3.73
Natural gas per Mcf, including impact of hedging activities (2)	$ 3.34
NGLs per Bbl, excluding impact of hedging activities	$ 31.99
NGLs per Bbl, including impact of hedging activities (2)	$ 28.09
Average sales price per Boe, excluding impact of hedging activities	$ 41.07
Average sales price per Boe, including impact of hedging activities (2)	$ 38.11

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

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

	For the Nine Months Ended September 30, 2014
Selected operating expenses per Boe:	
Production taxes	$ 1.86
Lease operating expenses	$ 5.03
Transportation, treating and gathering	$ 0.60

(4) Lease operating expenses for the three and nine months ended September 30, 2015 include $1.1 million and $3.8 million, respectively, of workover expense for one-time production enhancing workovers completed on certain WEHLU wells. Excluding workover expense, lease operating expense per Boe for the three and nine months ended September 30, 2015 would have been $3.30 per Boe and $4.01 per Boe, respectively, compared to $4.63 per Boe and $4.95 per Boe for the three and nine months ended September 30, 2014, respectively.

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

	For the Nine Months Ended September 30, 2014
Selected operating expenses per Boe:	
Production costs	$ 5.40

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

Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) were $17.1 million for the three months ended September 30, 2015, down 51% from $35.1 million for the three months ended September 30, 2014. The decrease

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in revenues was the result of a 65% decrease in weighted average realized equivalent prices offset by a 39% increase in production. In addition to overall adverse commodity price conditions, we continue to be impacted by significant negative gas basis differentials in Appalachia and weakened NGLs pricing. Average daily production on an equivalent basis was 13.6 MBoe/d for the three months ended September 30, 2015 compared to 9.8 MBoe/d for the same period in 2014. Oil, condensate and NGLs production represented approximately 53% of total production for the three months ended September 30, 2015 compared to 48% of total production for the three months ended September 30, 2014.

Oil and condensate revenues represented approximately 75% of our total oil, condensate, natural gas and NGLs revenues for the three months ended September 30, 2015 compared to 65% for the three months ended September 30, 2014. Total liquids revenues (oil, condensate and NGLs) represented approximately 80% of our total oil, condensate, natural gas and NGLs revenues for both the three months ended September 30, 2015 and 2014. We continue to focus our drilling activity in the Mid-Continent oil play due to continued weakened natural gas and NGLs prices in the Appalachian Basin. Our average realized sales prices per Boe in the Appalachian Basin, excluding the impact of hedging activities, were $2.20 per Boe for the third quarter of 2015 compared to $19.15 per Boe for the third quarter of 2014 and to $4.98 per Boe for the second quarter of 2015 and to $10.34 per Boe for the first quarter of 2015. Appalachian Basin natural gas prices have shown some improvement subsequent to September 30, 2015. We expect our liquids revenues to continue to grow and be a significant percentage of total oil, condensate, natural gas and NGLs revenues during the remainder of 2015.

During the three months ended September 30, 2015, we had commodity derivative contracts covering approximately 38% of our oil and condensate production. The impact of hedging on oil and condensate sales during the three months ended September 30, 2015 was an increase of $2.0 million in oil and condensate revenues and resulted in an increase in total price realized from $38.89 per Bbl to $44.84 per Bbl. The gain on oil and condensate commodity derivatives contracts settled during the period includes a loss of $11,000 for amortization of prepaid premiums. During the three months ended September 30, 2014, the impact of hedging on oil and condensate sales was a decrease of $601,000, which resulted in a decrease in total price realized from $91.17 per Bbl to $88.77 per Bbl. For both periods, we designated 50% of our current crude hedges as price protection for our NGLs production.

During the three months ended September 30, 2015, we had commodity derivative contracts covering approximately 73% of our natural gas production, which resulted in a gain on natural gas commodity derivatives contracts settled during the quarter of $2.0 million and resulted in an increase in total price realized from $0.99 per Mcf to $1.57 per Mcf. The gain on natural gas commodity derivative contracts settled during the period includes a gain of $19,000 for amortization of prepaid premiums. Excluding the non-cash amortization, the impact of hedging on natural gas sales was an increase in revenues of $1.7 million of NYMEX hedge gains and $258,000 of basis hedge gains. During the three months ended September 30, 2014, the impact of hedging on natural gas sales was an increase of $78,000 in natural gas revenues resulting in an increase in total price realized from $2.53 per Mcf to $2.56 per Mcf.

During the three months ended September 30, 2015, we had commodity derivative contracts covering approximately 57% of our NGLs production. The impact of hedging on NGLs sales during the three months ended September 30, 2015 was an increase of $2.8 million in NGLs revenues and resulted in an increase in total price realized from $2.35 per Bbl to $10.64 per Bbl. The gain on NGLs commodity derivatives contracts settled during the period includes a loss of $11,000 for amortization of prepaid premiums. During the three months ended September 30, 2014, the impact of hedging on NGLs sales was a decrease of $437,000 in NGLs revenues which resulted in a decrease in total price realized from $28.56 per Bbl to $26.13 per Bbl.

The change in mark to market value for outstanding commodity derivatives contracts for the three months ended September 30, 2015 was a gain of $4.5 million compared to a gain of $7.6 million for the three months ended September 30, 2014. The change in the mark to market value is primarily the result of changes in hedge contracts during the period compared to the prior year.

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

Production taxes. We reported production taxes of $655,000 for the three months ended September 30, 2015 compared to $1.6 million for the three months ended September 30, 2014. The decrease in production taxes primarily resulted from lower commodity prices related to our Marcellus Shale properties. Production taxes for the three months ended September 30, 2015 and 2014 were approximately 3.8% and 4.4%, respectively, of oil, condensate, natural gas and NGLs revenues. The decrease in the production tax as a percentage of revenues is primarily the result of an increase in Mid-Continent revenues that benefit from an initial four-year production tax abatement reducing the rate from 7% to 1% on new horizontal wells drilled. Effective July 1, 2015, the production tax abatement on new horizontal wells drilled was reduced to an initial three-year production abatement period and the rate was reduced from 7% to 2%.

Lease operating expenses. We reported lease operating expenses ("LOE") of $5.2 million for the three months ended September 30, 2015 compared to $4.1 million for the three months ended September 30, 2014. Our total LOE was $4.17 per Boe for the three months ended September 30, 2015 compared to $4.59 per Boe for the same period in 2014. The increase in our LOE was primarily due to a $1.1 million increase in one-time workover expense for production enhancing workovers completed on certain WEHLU wells, a $158,000 increase in ad valorem taxes as a result of higher production volumes and a $72,000 increase in insurance due to additional wells offset by a $276,000 decrease in LOE. Excluding workover expense, LOE per Boe for the three months ended September 30, 2015 was $3.30 compared to $4.63 for the three months ended September 30, 2014.

Transportation, treating and gathering. We reported transportation expenses of $615,000 for the three months ended September 30, 2015 compared to $397,000 for the three months ended September 30, 2014. The increase in transportation expense is due to increased Appalachian production.

Depreciation, depletion and amortization. We reported depreciation, depletion and amortization ("DD&A") expense of $15.4 million for the three months ended September 30, 2015 up from $11.1 million for the three months ended September 30, 2014. The increase in DD&A expense was the result of a 39% increase in production. The DD&A rate for the three months ended September 30, 2015 was $12.32 per Boe compared to $12.33 per Boe for the same period in 2014.

Impairment of oil and natural gas properties. We reported an impairment of oil and natural gas properties of $182.0 million for the three months ended September 30, 2015. The impairment is the result of a 28% decline in the 12-month average natural gas price and a 40% decline in the 12-month average oil price used in the calculation of the full cost ceiling test at September 30, 2015 compared to September 30, 2014. For a description of the ceiling impairment determination and a discussion of the likelihood of future impairment charges in 2015 and the impact of recent price declines on such impairments, see Part I, Item 1. "Financial Statements, Note 3 – Property, Plant and Equipment."

General and administrative expense. We reported general and administrative expenses of $4.7 million for the three months ended September 30, 2015 compared to $4.0 million for the three months ended September 30, 2014. Non-cash stock-based compensation expense, which is included in general and administrative expense, was $1.2 million for the three months ended September 30, 2015 and 2014. Excluding stock-based compensation expense, general and administrative expense increased $699,000 to $3.5 million for the three months ended September 30, 2015 compared to the three months ended September 30, 2014. This increase is primarily due to $481,000 of costs incurred for the acquisition of Oklahoma properties from our AMI co-participant and higher legal costs.

Interest expense. We reported interest expense of $7.9 million for the three months ended September 30, 2015 compared to $7.0 million for the three months ended September 30, 2014. The increase in interest expense is primarily due to additional borrowings under the revolving credit facility.

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

Nine Months Ended September 30, 2015 compared to the Nine Months Ended September 30, 2014

Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) were $65.0 million for the nine months ended September 30, 2015, down 45% from $118.7 million for the nine months ended

September 30, 2014. The decrease in revenues was the result of a 61% decrease in weighted average realized prices offset by a 39% increase in production. In addition to overall adverse commodity price conditions, we continue to be impacted by significant negative natural gas basis differentials in Appalachia and weakened NGLs pricing due to excess supply. Excluding the benefit of a one-time revenue adjustment of $10.6 million related to an arbitration settlement for the nine months ended September 30, 2014, weighted average Boe realized prices decreased 57% for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014. Average daily production on an equivalent basis was 13.4 MBoe/d for the nine months ended September 30, 2015 compared to 9.6 MBoe/d for the same period in 2014. Oil, condensate and NGLs production represented approximately 53% of total production for the nine months ended September 30, 2015 compared to 46% of total production for the nine months ended September 30, 2014. The one-time arbitration settlement did not have any impact on year-to-date September 30, 2014 production volumes.

Oil and condensate revenues represented approximately 70% of our total oil, condensate, natural gas and NGLs revenues for the nine months ended September 30, 2015 compared to 52% for the nine months ended September 30, 2014. Total liquids revenues (oil, condensate and NGLs) represented approximately 78% of our total oil, condensate, natural gas and NGLs revenues for the nine month period ended September 30, 2015 compared to 66% for the nine month period ended September 30, 2014. Excluding a one-time adjustment related to an arbitration settlement, liquids revenues represented approximately 70% of our total oil, condensate, natural gas and NGLs revenues for the nine month period ended September 30, 2014. We continue to focus our drilling activity in the Mid-Continent oil play due to continued weakened natural gas and NGLs prices in the Appalachian Basin. Our average realized sales prices per Boe in the Appalachian Basin, excluding the impact of hedging activities and the one-time adjustment related to an arbitration settlement in 2014, were $5.58 per Boe for the nine months ended September 30, 2015 compared to $26.01 per Boe for the nine months ended September 30, 2014. Appalachian Basin natural gas prices have shown some improvement subsequent to September 30, 2015. We expect our liquids revenues to continue to grow and be a significant percentage of total oil, condensate, natural gas and NGLs revenues during the remainder of 2015.

During the nine months ended September 30, 2015, we had commodity derivative contracts covering approximately 30% of our oil and condensate production. The impact of hedging on oil and condensate sales during the nine months ended September 30, 2015 was an increase of $5.7 million in oil and condensate revenues and resulted in an increase in total price realized from $42.94 per Bbl to $48.30 per Bbl. The gain on oil and condensate commodity derivatives contracts settled during the period includes a loss of $32,000 for amortization of prepaid premiums and a loss of $585,000 related to deferred put premiums. During the nine months ended September 30, 2014, the impact of hedging on oil and condensate sales was a decrease of $2.4 million in oil and condensate revenues, which resulted in a decrease in total price realized from $93.83 per Bbl to $90.24 per Bbl. Excluding the benefit of a one-time revenue adjustment related to an arbitration settlement during the nine months ended September 30, 2014, the total price realized for oil and condensate including the loss on oil and condensate commodity derivatives contracts settled during the nine months ended September 30, 2014 would have decreased from $89.06 per Bbl to $85.47 per Bbl. For both periods, we designated 50% of our current crude hedges as price protection for our NGLs production.

During the nine months ended September 30, 2015, we had commodity derivative contracts covering approximately 66% of our natural gas production, which resulted in a gain on natural gas commodity derivatives contracts settled during the nine months ended September 30, 2015 of $5.9 million and resulted in an increase in total price realized from $1.36 per Mcf to $1.93 per Mcf. The gain on natural gas commodity derivative contracts settled during the period includes a gain of $29,000 for amortization of prepaid premiums. Excluding the non-cash amortization, the impact of hedging on natural gas sales was an increase in revenues of $5.5 million of NYMEX hedge gains and $324,000 of basis hedge gains. During the nine months ended September 30, 2014, the impact of hedging on natural gas sales was a decrease of $3.3 million in natural gas revenues resulting in a decrease in total price realized from $4.68 per Mcf to $4.29 per Mcf. Excluding the benefit of the one-time revenue adjustment related to an arbitration settlement during the nine months ended September 30, 2014, the total price realized for natural gas including the loss on natural gas commodity derivatives contracts settled during the nine months ended September 30, 2014 would have decreased from $3.73 per Mcf to $3.34 per Mcf.

During the nine months ended September 30, 2015, we had commodity derivative contracts covering approximately 49% of our NGLs production. The impact of hedging on NGLs sales during the nine months ended September 30, 2015 was an increase of $7.2 million in NGLs revenues and resulted in an increase in total price realized from $5.94 per Bbl to $14.32 per Bbl. The gain on NGLs commodity derivatives contracts settled during the period includes a loss of $32,000 for amortization of prepaid premiums and a loss of $585,000 related to deferred put premiums. During the nine months ended September 30, 2014, the impact of hedging on NGLs sales was a decrease of $2.1 million in NGLs revenues which resulted in a decrease in total price realized from $30.74 per Bbl to $26.85 per Bbl. Excluding the impact of the one-time revenue adjustment related to an arbitration settlement during the nine months ended September 30, 2014, the total price realized for NGLs including the loss on NGLs commodity derivatives contracts settled during the nine months ended September 30, 2014 would have decreased from $31.99 per Bbl to $28.09 per Bbl.

Gains related to the change in mark to market value for outstanding commodity derivatives contracts for the nine months ended September 30, 2015 were $986,000 compared to losses of $950,000 for the nine months ended

September 30, 2014. The decrease in the mark to market loss is primarily the result of lower commodity prices and the changes in hedge contracts during the period.

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

Production taxes. We reported production taxes of $2.3 million for the nine months ended September 30, 2015 compared to $5.5 million for the nine months ended September 30, 2014. Production taxes reported for the nine months ended September 30, 2014 include $584,000 of additional production taxes attributed to a one-time revenue adjustment resulting from an arbitration settlement. Excluding the 2014 adjustment, the decrease in production taxes primarily resulted from lower commodity prices related to our Marcellus Shale properties. Production taxes for the nine months ended September 30, 2015 and 2014 were approximately 3.6% and 4.6%, respectively, of oil, condensate, natural gas and NGLs revenues. The decrease in the production tax as a percentage of revenues is primarily the result of an increase in Mid-Continent revenues that benefit from an initial four-year production tax abatement reducing the rate from 7% to 1% on new horizontal wells drilled. Effective July 1, 2015, the production tax abatement on new horizontal wells drilled was reduced to an initial three-year production abatement period and the rate was reduced from 7% to 2%.

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Lease operating expenses. We reported LOE of $18.5 million for the nine months ended September 30, 2015 compared to $13.1 million for the nine months ended September 30, 2014. Our total LOE was $5.07 per Boe for the nine months ended September 30, 2015 compared to $4.96 per Boe for the same period in 2014. Excluding $185,000 of a one-time reduction to LOE related to an arbitration settlement during the nine months ended September 30, 2014, our total LOE would have been $5.03 per Boe for the nine months ended September 30, 2014. The increase in our LOE was primarily due to a $3.8 million increase in one-time workover expense for production enhancing workovers completed on certain WEHLU wells, a $611,000 increase in controllable LOE resulting from new wells and higher overall costs associated with producing oil versus natural gas, an increase in ad valorem taxes of $476,000 and a $497,000 increase in insurance costs. Excluding workover expense, LOE per Boe for the nine months ended September 30, 2015 would have been $4.01 compared to $4.95 for the nine months ended September 30, 2014.

Transportation, treating and gathering. We reported transportation expenses of $1.7 million for the nine months ended September 30, 2015 compared to $3.2 million for the nine months ended September 30, 2014. Transportation, treating and gathering expense reported for the nine months ended September 30, 2014 includes $1.6 million of expense attributed to a one-time adjustment related to an arbitration settlement. Excluding the one-time adjustment, year to date September 30, 2014 transportation expense would have been $1.6 million.

Depreciation, depletion and amortization. We reported DD&A expense of $45.9 million for the nine months ended September 30, 2015 up from $33.8 million for the nine months ended September 30, 2014. The increase in DD&A expense was the result of a 39% increase in production partially offset by a 2% decrease in the DD&A rate per Boe. The DD&A rate for the nine months ended September 30, 2015 was $12.60 per Boe compared to $12.83 per Boe for the same period in 2014. The decrease in the rate is primarily due to higher proved reserves at September 30, 2015 compared to September 30, 2014 and impairments of proved costs taken in 2015.

Impairment of oil and natural gas properties. We reported an impairment of oil and natural gas properties of $282.1 million for the nine months ended September 30, 2015. The impairment is the result of a 28% decline in the 12-month average natural gas price and a 40% decline in the 12-month average oil price used in the calculation of our full cost ceiling test at September 30, 2015 compared to September 30, 2014. For a description of the ceiling test impairment determination and a discussion of the likelihood of future impairment charges in 2015 and the impact of recent price declines on such impairments, see Part I, Item 1. "Financial Statements, Note 3 – Property, Plant and Equipment." At September 30, 2015, our ceiling test impairment calculation was based on SEC pricing of $3.06 per MMBtu of Henry Hub spot natural gas and $59.21 per barrel of West Texas Intermediate spot oil which compares to the trailing 12-month unweighted average commodity prices subsequent to quarter end as of October 1, 2015 pricing of $2.94 per MMBtu of Henry Hub spot natural gas and $55.84 per barrel of West Texas Intermediate spot oil.

General and administrative expense. We reported general and administrative expenses of $13.4 million for the nine months ended September 30, 2015 compared to $12.7 million for the nine months ended September 30, 2014. Non-cash stock-based compensation expense, which is included in general and administrative expense, increased $223,000 to $3.9 million for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014. Excluding stock-based compensation expense, general and administrative expense increased $471,000 to $9.4 million for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014. This increase is primarily due to $481,000 of costs incurred for the acquisition of Oklahoma properties from our AMI co-participant.

Interest expense. We reported interest expense of $22.4 million for the nine months ended September 30, 2015 compared to $20.8 million for the nine months ended September 30, 2014. The increase in interest expense is primarily due to additional borrowings under the revolving credit facility.

Dividends on preferred stock. We reported dividends on preferred stock of $10.9 million and $10.8 million for the nine months ended September 30, 2015 and 2014, respectively. The Series A Preferred Stock had a stated value and liquidation preference of approximately $101.1 million at September 30, 2015 and 2014, respectively, and carries a cumulative dividend rate of 8.625% per annum. Dividends on the Series A Preferred Stock were $6.5 million for the nine months ended September 30, 2015 and 2014, respectively. The Series B Preferred Stock, issued during November 2013, had a stated value and liquidation preference of $53.5 million at September 30, 2015 and 2014, respectively, and carries a cumulative dividend rate of 10.75% per annum. Dividends on the Series B Preferred Stock were $4.3 million for the nine months ended September 30, 2015 and 2014. Based on the number of shares of Series A Preferred Stock and Series B Preferred Stock outstanding at September 30, 2015, our future stated preferred dividend expense is approximately $3.6 million per quarter, which is subject to being declared and paid monthly.

Liquidity and Capital Resources

Overview. Our primary sources of liquidity and capital resources are internally generated cash flows from operating activities, availability under the Revolving Credit Facility, access to capital markets, to the extent available, and potential asset sales. If commodity prices remain low or decline further, our liquidity will be adversely affected. A sustained low commodity price environment may (i) negatively impact our ability to comply with our financial covenants in future periods and (ii) lead to reductions

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in our proved reserves and the estimated future value thereof. We have assessed our financial condition, our liquidity situation under our Revolving Credit Facility, the current capital and credit markets and options given different scenarios of commodity prices and we believe that the funds from operating cash flows, available borrowings under our Revolving Credit Facility and proceeds from capital markets transactions and asset sales should be sufficient to meet our cash requirements for at least the next 12 months. Although we cannot predict how an extended period of commodity prices at existing levels will affect our operations and liquidity levels, we continually evaluate our capital needs and compare them to our capital resources and ability to raise funds in the financial markets and adjust capital expenditures in response to changes in oil, condensate, natural gas and NGLs prices, drilling results and cash flow.

For the nine months ended September 30, 2015, we reported cash flows provided by operating activities of $54.8 million. For the nine months ended September 30, 2015, we reported net cash used in investing activities of $77.4 million primarily for the development of oil and natural gas properties of $121.1 million offset by $47.9 million in proceeds from the sale of non-core oil and natural gas properties located in the Mid-Continent area. For the nine months ended September 30, 2015, we reported net cash provided by financing activities of $21.9 million, consisting primarily of $35.0 million of net borrowings under our Revolving Credit Facility partially offset by $10.9 million of preferred stock dividends paid and $1.4 million of tax withholding related to restricted stock and PBU vestings during the period. As a result of these activities, our cash and cash equivalents balance decreased by $657,000, resulting in a cash and cash equivalents balance of $10.4 million at September 30, 2015.

At September 30, 2015, we had a net working capital deficit of approximately $3.4 million. At September 30, 2015, availability under our Revolving Credit Facility was $120.0 million.

Future capital and other expenditure requirements. Capital expenditures for the remainder of 2015, including the Mid-Continent acquisition of $43.3 million before adjustments, are currently projected to be approximately $58.3 million. Excluding the acquisition, in the Appalachian Basin and Mid-Continent, we expect to spend $4.9 million and $8.8 million, respectively, for drilling, completion, infrastructure, lease acquisition and seismic costs. In addition, we have allocated $1.3 million for capitalized general and administrative costs. We plan to fund our remaining 2015 capital budget through existing cash balances, internally generated cash flow from operating activities, borrowings under the Revolving Credit Facility, the divestiture of our Marcellus Shale and Utica/Point Pleasant assets and possible capital markets transactions.

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

We are currently evaluating our capital plans for 2016; however, based upon current commodity price volatility, we do not anticipate finalizing our capital plan until early 2016. However, we expect our capital expenditures for 2016 to be reduced from 2015 spending levels.

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

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

At September 30, 2015, the estimated fair value of all of our commodity derivative instruments was a net asset of \$27.3 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 the remainder of 2015 through 2018, we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flows for those periods. While mitigating negative effects of falling commodity prices, certain derivative contracts also limit the benefits we could receive from increases in commodity prices. In conjunction with certain commodity derivative hedging activity, we deferred the payment of certain put premiums for the production month period October 2015 through December 2018. At September 30, 2015, we had a current commodity premium payable of \$2.4 million and a long-term

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commodity premium payable of $3.6 million. The put premium liabilities become payable monthly as the hedge production month becomes the prompt production month.

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

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

Revolving Credit Facility. Our Revolving Credit Facility provides for a maximum amount of $500.0 million, subject to a borrowing base, which, at September 30, 2015, was $200.0 million. At September 30, 2015, we had $80.0 million of borrowings outstanding under our Revolving Credit Facility. As of November 2, 2015, we had $95.0 million of borrowings outstanding under our Revolving Credit Facility.

On March 9, 2015, the Company, together with the parties thereto, entered into a Master Assignment, Agreement and Amendment No. 5 (“Amendment No. 5”) to Second Amended and Restated Credit Agreement. Amendment No. 5 amended the Revolving Credit Facility to, among other things, (i) increase the borrowing base from $145.0 million to $200.0 million, (ii) adjust the total leverage ratio for each fiscal quarter ending on or after March 31, 2015 but prior to September 30, 2016, to 5.25 to 1.00; for the fiscal quarter ending on September 30, 2016, to 5.00 to 1.00; for the fiscal quarter ending on December 31, 2016, to 4.75 to 1.00; for the fiscal quarter ending on March 31, 2017, to 4.25 to 1.00; and for each fiscal quarter ending on or after June 30, 2017, to 4.00 to 1.00, (iii) adjust the interest coverage ratio for each fiscal quarter ending on or after March 31, 2015 but prior to March 31, 2016, to 2.00 to 1.00 and for each fiscal quarter ending on or after March 31, 2016, to 2.50 to 1.00, and (iv) add the senior secured leverage ratio covenant, such ratio not to exceed, (a) for each fiscal quarter ending on or after March 31, 2015 but prior to June 30, 2016, 2.25 to 1.00 and (b) for each fiscal quarter ending on or after June 30, 2016, 2.00 to 1.00 provided that this senior secured leverage ratio shall cease to apply commencing with the first fiscal quarter end occurring after June 30, 2016 for which the total leverage ratio is equal to or less than 4.00 to 1.00. As a condition to borrow funds or obtain letters of credit under our Revolving Credit Facility, we must remain in compliance with the financial ratios in our Credit Agreement and we also must certify to our bank lenders that our representations and warranties contained in the Credit Agreement remain true and correct. If we do not meet our financial ratios or are unable to give the required certification, then we would need a waiver or amendment from our bank lenders in order to continue to be able to borrow or obtain letters of credit under our Revolving Credit Facility. Although we believe our bank lenders are well secured under the terms of our Revolving Credit Facility and the bank lenders have provided financial ratio relief in the past such as in the recent Amendment No. 5, there is no assurance that the bank lenders would further waive or amend our financial ratios or any other requirements that are conditions to future lending or issuances of letters of credit.

Borrowing base redeterminations are scheduled semi-annually in May and November of each calendar year. The Company and its lender group may each request one additional unscheduled redetermination during any six-month period between scheduled redeterminations. At September 30, 2015, the Revolving Credit Facility had a borrowing base of $200.0 million, with $80.0 million borrowings outstanding and availability of $120.0 million. The next regularly scheduled redetermination is set for May 2016. Future increases in the borrowing base in excess of the original $50.0 million are limited to 17.5% of the increase in adjusted consolidated net tangible assets (“ACNTA”) as defined in the indenture pursuant to which our Notes are issued.

Future borrowings under our Revolving Credit Facility in excess of $50.0 million are, with certain exceptions for additional permitted borrowings, limited to 17.5% of ACNTA, as defined in the indenture pursuant to which our Notes are issued. In light of the dramatic drop in commodities prices occurring this year, our ACNTA is expected to be reduced substantially at year-end 2015. As a result, we believe that it is likely that after December 31, 2015 our ability to borrow under our Revolving Credit Facility will be limited by the covenants in our Notes indenture to an amount less than our current $200.0 million borrowing base. Absent an amendment to this indenture covenant approved by the indenture trustee and holders of a majority in principal amount of our Notes, which we are not currently contemplating seeking to obtain nor are we assured of obtaining if we did pursue, we may determine to draw the full amount of un-borrowed available funds under our Revolving Credit Facility on or prior to determining year-end 2015 ACNTA in order to have such funds available. Future reductions in our borrowing base to an amount below amounts borrowed would have to be repaid from such funds or other funds generated by operations or asset sales.

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

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

Series A Preferred Stock. We pay cumulative dividends on the Series A Preferred Stock at a fixed rate of 8.625% per annum of the aggregate $101.1 million stated value and liquidation preference. For the three and nine months ended September 30, 2015, we recognized dividend expense of $2.2 million and $6.5 million, respectively, for the Series A Preferred Stock.

Series B Preferred Stock. We pay cumulative dividends on the Series B Preferred Stock at a fixed rate of 10.75% per annum of the aggregate $53.5 million stated value and liquidation preference. For the three and nine months ended September 30, 2015, we recognized dividend expense of $1.4 million and $4.3 million, respectively, for the Series B Preferred Stock.

Off-Balance Sheet Arrangements

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

Commitments and Contingencies

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

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

Critical Accounting Policies and Estimates

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

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates could have a material impact on our consolidated results of operations or financial condition.

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

Recent Accounting Developments

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Our major commodity price risk exposure is to the prices received for our oil, condensate, natural gas and NGLs production. Our results of operations and operating cash flows are affected by changes in market prices. Realized commodity prices received for our production are the spot prices applicable to oil, condensate, natural gas and NGLs in the region produced. Prices received for oil, condensate, natural gas and NGLs are volatile, unpredictable and beyond our control. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. For the three and nine months ended September 30, 2015, a 10% change in the prices received for oil, condensate, natural gas and NGLs production would have had an approximate \$1.7 million and \$6.5 million, impact on our revenues prior to hedge transactions to mitigate our commodity pricing risk, respectively. See Part I, Item 1. “Financial Statements, Note 6 – Derivative Instruments and Hedging Activity” of this report for additional information regarding our hedging activities.

Interest Rate Risk

We are exposed to changes in interest rates as a result of our Revolving Credit Facility. At September 30, 2015, we had \$80.0 million of borrowings outstanding under our Revolving Credit Facility. We have not entered into interest rate hedging arrangements in the past, and have no current plans to do so. Due to the potential for fluctuating balances in the amount outstanding under our Revolving Credit Facility, we do not believe such arrangements to be cost effective. The amount outstanding under the Notes is at fixed interest of 8.625% per annum. We currently do not use interest rate derivatives to mitigate our exposure to the volatility in interest rates, including under the Revolving Credit Facility, as this risk is minimal.

Item 4. Controls and Procedures

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

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

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

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

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

Issuer Purchases of Equity Securities

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

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 the Plan
August 1, 2015 – August 31, 2015	3,167	1.66	—	n/a

Shares purchased represent 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.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosure

Not applicable.

Item 5. Other Information

Amendment to Bylaws

On November 4, 2015, the board of directors (the “Board”) of the Company adopted Amended and Restated Bylaws (the “Bylaws”) of the Company. The Bylaws became effective immediately and include, among other things, the following changes:

- Providing for additional disclosure requirements for notices of director nominations and stockholder proposals.
- Clarifying the Board’s authority to cancel, postpone or reschedule stockholder meetings.
- Clarifying the powers of the chairman of a stockholder meeting.
- Providing for an explicit confidentiality obligation for stockholder-nominated directors.
- Designating the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain legal actions.

The foregoing description of the Bylaws is not complete and is qualified in its entirety by reference to the complete text of the Bylaws, a copy of which is filed as Exhibit 3.2 to this Quarterly Report on Form 10-Q and incorporated by reference herein.

Item 6. Exhibits

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

SIGNATURES

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

GASTAR EXPLORATION INC.

Date:	November 5, 2015	By: /s/ J. RUSSELL PORTER J. Russell Porter President and Chief Executive Officer (Duly authorized officer and principal executive officer)
Date:	November 5, 2015	By: /s/ MICHAEL A. GERLICH Michael A. Gerlich Senior Vice President and Chief Financial Officer (Duly authorized officer and principal financial and accounting officer)

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EXHIBIT INDEX

Exhibit Number	Description
2.1	Amended and Restated Plan of Arrangement Under Section 193 of the Business Corporations Act (Alberta), effective as of November 14, 2013 (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on November 15, 2013. File No. 001-32714).
2.2	Agreement and Plan of Merger, dated as of January 31, 2014, among Gastar Exploration, Inc. and Gastar Exploration USA, Inc. (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on January 31, 2014. File No. 000-55138).
2.3**	Purchase and Sale Agreement, dated May 1, 2015, by and between Gastar Exploration Inc. and Oklahoma Energy Acquisitions, LP. (incorporated by reference to Exhibit 2.3 of the Quarterly Report on Form 10-Q filed with the SEC on May 7, 2015. File No. 001-35211).
2.4	First Amendment of Purchase and Sale Agreement, dated June 22, 2015, by and between Gastar Exploration Inc. and Oklahoma Energy Acquisitions, LP (incorporated by reference to Exhibit 2.4 of the Quarterly Report on Form 10-Q filed with the SEC on August 6, 2015. File No. 001-35211).
2.5**	Purchase and Sale Agreement, dated October 14, 2015, by and between Gastar Exploration Inc. and Husky Ventures, Inc., Silverstar of Nevada, Inc., Maximus Exploration, LLC and Atwood Acquisitions, LLC (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on October 16, 2015. File No. 001-35211).
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†	Amended and Restated Bylaws of Gastar Exploration Inc. dated November 4, 2015.
3.3	Certificate of Merger of Gastar Exploration, Inc. into Gastar Exploration USA, Inc. (incorporated by reference to Exhibit 3.1 of the Current Report on Form 8-K filed with the SEC on January 31, 2014. File No. 000-55138).
3.4	Certificate of Designation of Rights and Preferences of 8.625% Series A Cumulative Preferred Stock (incorporated by reference to Exhibit 3.3 of Gastar Exploration USA, Inc.'s Form 8-A filed on June 20, 2011. File No. 001-35211).
3.5	Certificate of Designation of Rights and Preferences of 10.75% Series B Cumulative Preferred Stock (incorporated by reference to Exhibit 3.4 of the Form 8-A filed with the SEC on November 1, 2013. File No. 001-35211).
31.1†	Certification of Principal Executive Officer of Gastar Exploration Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2†	Certification of Principal Financial Officer of Gastar Exploration Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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

† 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.

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

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