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	Total of Notional Volume (in MMBtus)	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.

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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,		For the Nine Months Ended September 30,	
	2015	2014	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

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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:

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)
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	% 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.

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