GULFPORT ENERGY CORP
Form 10-Q
November 03, 2016
Table of Contents

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

FORM 10-Q

(Mark One)
ýQUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2016 OR
¨TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number 000-19514

Gulfport Energy Corporation
(Exact Name of Registrant As Specified in Its Charter)

Delaware	73-1521290
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification Number)
14313 North May Avenue, Suite 100 Oklahoma City, Oklahoma	73134
(Address of Principal Executive Offices)	(Zip Code)

(405) 848-8807
(Registrant Telephone Number, Including Area Code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	The NASDAQ Stock Market LLC

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (Section 232.405 of this chapter) during the preceding 12 months (or such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):
Large Accelerated filer ý Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No ý
As of November 1, 2016, 125,453,533 shares of the registrant’s common stock were outstanding.

Table of Contents

GULFPORT ENERGY CORPORATION
TABLE OF CONTENTS

1

Table of Contents

GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2016	December 31, 2015
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$364,276	$112,974
Accounts receivable—oil and gas	127,788	71,872
Accounts receivable—related parties	96	16
Prepaid expenses and other current assets	10,740	3,905
Short-term derivative instruments	39,363	142,794
Deferred tax asset	38	—
Total current assets	542,301	331,561
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $1,723,821 and $1,817,701 excluded from amortization in 2016 and 2015, respectively	5,816,458	5,424,342
Other property and equipment	54,460	33,171
Accumulated depletion, depreciation, amortization and impairment	(3,613,662)	(2,829,110)
Property and equipment, net	2,257,256	2,628,403
Other assets:		
Equity investments	251,309	242,393
Long-term derivative instruments	15,262	51,088
Deferred tax asset	4,203	74,925
Other assets	5,512	6,364
Total other assets	276,286	374,770
Total assets	$3,075,843	$3,334,734
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$304,341	$265,128
Asset retirement obligation—current	75	75
Short-term derivative instruments	37,220	437
Deferred tax liability	—	50,697
Current maturities of long-term debt	220	179
Total current liabilities	341,856	316,516
Long-term derivative instrument	14,907	6,935
Asset retirement obligation—long-term	32,910	26,362
Long-term debt, net of current maturities	961,050	946,084
Total liabilities	1,350,723	1,295,897
Commitments and contingencies (Note 10)		
Preferred stock, $.01 par value; 5,000,000 authorized, 30,000 authorized as redeemable 12% cumulative preferred stock, Series A; 0 issued and outstanding	—	—
Stockholders' equity:		
	1,253	1,082

Common stock - $.01 par value, 200,000,000 authorized, 125,453,533 issued and outstanding at September 30, 2016 and 108,322,250 at December 31, 2015		
Paid-in capital	3,245,393	2,824,303
Accumulated other comprehensive loss	(50,816)	(55,177)
Retained deficit	(1,470,710)	(731,371)
Total stockholders’ equity	1,725,120	2,038,837
Total liabilities and stockholders’ equity	$ 3,075,843	$ 3,334,734

See accompanying notes to consolidated financial statements.

Table of Contents

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
	(In thousands, except share data)			
Revenues:				
Gas sales	$155,185	$179,215	$228,419	$363,656
Oil and condensate sales	23,507	41,747	61,161	111,712
Natural gas liquid sales	15,000	9,431	32,914	43,396
Other (expense) income	(6)	176	3	392
	193,686	230,569	322,497	519,156
Costs and expenses:				
Lease operating expenses	17,471	17,568	48,789	51,411
Production taxes	3,525	3,593	9,492	11,163
Midstream gathering and processing	45,475	42,166	122,476	100,451
Depreciation, depletion and amortization	62,285	90,329	183,414	251,393
Impairment of oil and gas properties	212,194	594,776	601,806	594,776
General and administrative	10,467	11,001	32,941	31,315
Accretion expense	269	212	777	594
	351,686	759,645	999,695	1,041,103
LOSS FROM OPERATIONS	(158,000)	(529,076)	(677,198)	(521,947)
OTHER (INCOME) EXPENSE:				
Interest expense	12,787	14,124	44,892	34,906
Interest income	(337)	(279)	(822)	(536)
Insurance proceeds	(3,750)	—	(3,750)	—
(Income) loss from equity method investments	(5,997)	61,891	25,576	57,036
	2,703	75,736	65,896	91,406
LOSS BEFORE INCOME TAXES	(160,703)	(604,812)	(743,094)	(613,353)
INCOME TAX BENEFIT	(3,407)	(216,603)	(3,755)	(219,338)
NET LOSS	$(157,296)	$(388,209)	$(739,339)	$(394,015)
NET LOSS PER COMMON SHARE:				
Basic	$(1.25)	$(3.59)	$(6.12)	$(4.06)
Diluted	$(1.25)	$(3.59)	$(6.12)	$(4.06)
Weighted average common shares outstanding—Basic	125,408,866	108,217,062	120,771,046	96,935,897
Weighted average common shares outstanding—Diluted	125,408,866	108,217,062	120,771,046	96,935,897

See accompanying notes to consolidated financial statements.

Table of Contents

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS
(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
	(In thousands)			
Net loss	$(157,296)	$(388,209)	$(739,339)	$(394,015)
Foreign currency translation adjustment (1)	(4,013)	(11,538)	4,361	(23,275)
Other comprehensive (loss) income	(4,013)	(11,538)	4,361	(23,275)
Comprehensive loss	$(161,309)	$(399,747)	$(734,978)	$(417,290)

(1) Net of $2.8 million and $2.8 million in taxes for the three and nine months ended September 30, 2016, respectively. No taxes were recorded for three and nine months ended September 30, 2015.

See accompanying notes to consolidated financial statements.

Table of Contents

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS’ EQUITY
(Unaudited)

	Common Stock		Paid-in	Accumulated Other Comprehensive	Retained	Total Stockholders’
	Shares	Amount	Capital	(Loss) Income	Earnings	Equity
	(In thousands, except share data)					
Balance at January 1, 2016	108,322,250	$ 1,082	$ 2,824,303	$ (55,177)	$ (731,371)	$ 2,038,837
Net loss	—	—	—	—	(739,339)	(739,339)
Other Comprehensive Income	—	—	—	4,361	—	4,361
Stock Compensation	—	—	9,550	—	—	9,550
Issuance of Common Stock in public offerings, net of related expenses	16,905,000	169	411,542	—	—	411,711
Issuance of Restricted Stock	226,283	2	(2)	—	—	—
Balance at September 30, 2016	125,453,533	$ 1,253	$ 3,245,393	$ (50,816)	$ (1,470,710)	$ 1,725,120
Balance at January 1, 2015	85,655,438	$ 856	$ 1,828,602	$ (26,675)	$ 493,513	$ 2,296,296
Net loss	—	—	—	—	(394,015)	(394,015)
Other Comprehensive Loss	—	—	—	(23,275)	—	(23,275)
Stock Compensation	—	—	10,556	—	—	10,556
Issuance of Common Stock in public offerings, net of related expenses	22,425,000	224	981,299			981,523
Issuance of Restricted Stock	156,393	2	(2)	—	—	—
Issuance of Common Stock through exercise of options	5,000	—	45	—	—	45
Balance at September 30, 2015	108,241,831	$ 1,082	$ 2,820,500	$ (49,950)	$ 99,498	$ 2,871,130

See accompanying notes to consolidated financial statements.

Table of Contents

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine months ended September 30,	
	2016	2015
	(In thousands)	
Cash flows from operating activities:		
Net loss	$(739,339)	$(394,015)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Accretion of discount—Asset Retirement Obligation	777	594
Depletion, depreciation and amortization	183,414	251,393
Impairment of oil and gas properties	601,806	594,776
Stock-based compensation expense	5,730	6,334
Loss from equity investments	25,988	64,062
Loss (gain) on derivative instruments	184,013	(58,873)
Deferred income tax expense (benefit)	17,211	(219,338)
Amortization of loan commitment fees	2,912	2,287
Amortization of note discount and premium	(1,716)	(1,611)
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(55,916)	37,587
Increase in accounts receivable—related party	(80)	(103)
Increase in prepaid expenses	(6,835)	(12,442)
Increase (decrease) in accounts payable, accrued liabilities and other	28,265	(34,440)
Settlement of asset retirement obligation	(955)	(1,120)
Net cash provided by operating activities	245,275	235,091
Cash flows from investing activities:		
Deductions to cash held in escrow	8	8
Additions to other property and equipment	(20,131)	(8,209)
Additions to oil and gas properties	(441,128)	(1,373,292)
Proceeds from sale of oil and gas properties	41,534	18,192
Contributions to equity method investments	(18,510)	(13,837)
Distributions from equity method investments	14,220	4,761
Insurance proceeds	3,750	—
Net cash used in investing activities	(420,257)	(1,372,377)
Cash flows from financing activities:		
Principal payments on borrowings	(1,685)	(350,130)
Borrowings on line of credit	—	250,000
Proceeds from bond issuance	—	350,000
Borrowings on term loan	16,499	—
Debt issuance costs and loan commitment fees	(241)	(8,381)
Proceeds from issuance of common stock, net of offering costs	411,711	981,568
Net cash provided by financing activities	426,284	1,223,057
Net increase in cash and cash equivalents	251,302	85,771
Cash and cash equivalents at beginning of period	112,974	142,340
Cash and cash equivalents at end of period	$364,276	$228,111
Supplemental disclosure of cash flow information:		
Interest payments	$35,193	$24,195

Income tax payments	$—	$29,753
Supplemental disclosure of non-cash transactions:		
Capitalized stock based compensation	$3,820	$4,222
Asset retirement obligation capitalized	$6,726	$5,736
Interest capitalized	$8,920	$12,041
Foreign currency translation gain (loss) on equity method investments	$7,137	$(23,275)

See accompanying notes to consolidated financial statements.

Table of Contents

GULFPORT ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

These consolidated financial statements have been prepared by Gulfport Energy Corporation (the “Company” or “Gulfport”) without audit, pursuant to the rules and regulations of the Securities and Exchange Commission (the "SEC"), and reflect all adjustments which, in the opinion of management, are necessary for a fair presentation of the results for the interim periods, on a basis consistent with the annual audited consolidated financial statements. All such adjustments are of a normal recurring nature. Certain information, accounting policies, and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been omitted pursuant to such rules and regulations, although the Company believes that the disclosures are adequate to make the information presented not misleading. These consolidated financial statements should be read in conjunction with the consolidated financial statements and the summary of significant accounting policies and notes thereto included in the Company's most recent annual report on Form 10-K. Results for the three and nine month periods ended September 30, 2016 are not necessarily indicative of the results expected for the full year.

1. ACQUISITIONS

In April 2015, the Company entered into an agreement to acquire Paloma Partners III, LLC ("Paloma") for a total purchase price of approximately $301.9 million, subject to certain adjustments. Paloma holds approximately 24,000 net nonproducing acres in the Utica Shale of Ohio. In accordance with the agreement, the Company deposited $75.0 million into an escrow account. At the closing of the transaction the deposit was credited toward the purchase price. This transaction closed on August 31, 2015 for a purchase price of approximately $302.3 million, net of purchase price adjustments. At closing, approximately $30.1 million of the purchase price was placed in escrow as security to the Company for potential indemnification claims that may occur as a result of the sale.

On June 9, 2015, the Company completed the acquisition of 6,198 gross and net acres located in Belmont and Jefferson Counties, Ohio from American Energy-Utica, LLC ("AEU") for a purchase price of approximately $68.2 million, subject to adjustment. On June 12, 2015, the Company completed the acquisition of 38,965 gross (27,228 net) acres located in Monroe County, Ohio, 14.6 MMcf per day of average net production (estimated for April 2015), 18 gross (11.3 net) drilled but uncompleted wells, an 11 mile gas gathering system and a four well pad location from AEU for a total purchase price of approximately $319.0 million (the "Monroe Acquisition"). On June 29, 2015, the Company acquired an additional 4,950 gross (1,900 net) acres in Monroe County for an additional $18.2 million from AEU. The total purchase price of these transactions, collectively referred to as the ("AEU Acquisition"), was approximately $405.4 million ($405.0 million net of purchase price adjustments). At closing, approximately $67.1 million of the purchase price was placed in escrow pending completion of title review after the closing. In December 2015, approximately $2.4 million of the escrow was released and returned to the Company with the balance of the escrow account distributed to the seller based on final title review.

The AEU Acquisition qualified as a business combination for accounting purposes and, as such, the Company estimated the fair value of the acquired properties as of the June 12, 2015 acquisition date. The fair value of the assets and liabilities acquired was estimated using assumptions that represent Level 3 inputs. See Note 12 for additional discussion of the measurement inputs.

The Company estimated that the consideration paid in the AEU Acquisition for these properties approximated the fair value that would be paid by a typical market participant. As a result, no goodwill or bargain purchase gain was recognized in conjunction with the purchase.

The following table summarizes the consideration paid in the AEU Acquisition to acquire the properties and the fair value amount of the assets acquired as of June 12, 2015. Both the consideration paid and the fair value assigned to the assets is preliminary and subject to adjustment upon final closing.

Table of Contents

	(In thousands)
Consideration paid	
Cash, net of purchase price adjustments	$ 405,029
Fair value of identifiable assets acquired	
Oil and natural gas properties	
Proved	$ 70,804
Unevaluated	334,225
Fair value of net identifiable assets acquired	$ 405,029

2. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of September 30, 2016 and December 31, 2015 are as follows:

	September 30, 2016	December 31, 2015
	(In thousands)	
Oil and natural gas properties	$ 5,816,458	$ 5,424,342
Office furniture and fixtures	13,862	12,589
Building	36,931	16,915
Land	3,667	3,667
Total property and equipment	5,870,918	5,457,513
Accumulated depletion, depreciation, amortization and impairment	(3,613,662)	(2,829,110)
Property and equipment, net	$ 2,257,256	$ 2,628,403

At September 30, 2016, the net book value of the Company's oil and natural gas properties was above the calculated ceiling as a result of the reduced commodity prices for the period leading up to September 30, 2016. As a result, the Company recorded an impairment of its oil and natural gas properties under the full cost method of accounting of $212.2 million and $601.8 million for the three and nine months ended September 30, 2016, respectively. An impairment of $594.8 million was required for oil and natural gas properties for the three and nine months ended September 30, 2015.

Included in oil and natural gas properties at September 30, 2016 is the cumulative capitalization of $122.8 million in general and administrative costs incurred and capitalized to the full cost pool. General and administrative costs capitalized to the full cost pool represent management’s estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized general and administrative costs were approximately $7.2 million and $22.2 million for the three and nine months ended September 30, 2016, respectively, and $7.3 million and $20.8 million for the three and nine months ended September 30, 2015, respectively.

The following table summarizes the Company’s non-producing properties excluded from amortization by area at September 30, 2016:

	September 30, 2016
	(In thousands)
Utica	$ 1,718,379
Niobrara	4,857
Southern Louisiana	443
Bakken	97

Other	45
	$ 1,723,821

8

At December 31, 2015, approximately $1.8 billion of non-producing leasehold costs was not subject to amortization. The Company evaluates the costs excluded from its amortization calculation at least annually. Subject to industry conditions and the level of the Company's activities, the inclusion of most of the above referenced costs into the Company's amortization calculation typically occurs within three to five years. However, the majority of the Company's non-producing leases have five-year extension terms which could extend this time frame beyond five years.

A reconciliation of the Company's asset retirement obligation for the nine months ended September 30, 2016 and 2015 is as follows:

	September 30, 2016	September 30, 2015
	(In thousands)	
Asset retirement obligation, beginning of period	$26,437	$ 17,938
Liabilities incurred	6,726	5,736
Liabilities settled	(955)	(1,120)
Accretion expense	777	594
Asset retirement obligation as of end of period	32,985	23,148
Less current portion	75	75
Asset retirement obligation, long-term	$32,910	$ 23,073

3. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of September 30, 2016 and December 31, 2015:

		Carrying value		(Income) loss from equity method investments			
	Approximate ownership %	September 30, 2016	December 31, 2015	Three months ended September 30,		Nine months ended September 30,	
				2016	2015	2016	2015
		(In thousands)					
Investment in Tatex Thailand II, LLC	23.5 %	$—	$ —	$(253)	$—	$(412)	$189
Investment in Tatex Thailand III, LLC	17.9 %	—	—	—	—	—	—
Investment in Grizzly Oil Sands ULC	24.9999 %	48,595	50,645	363	58,653	24,811	71,289
Investment in Timber Wolf Terminals LLC	50.0 %	993	999	3	—	7	13
Investment in Windsor Midstream LLC	22.5 %	25,797	27,955	(9,014)	(323)	(12,062)	(18,229)
Investment in Stingray Cementing LLC	50.0 %	2,084	2,487	79	(12)	187	160
Investment in Blackhawk Midstream LLC	48.5 %	—	—	—	—	—	(7,217)
Investment in Stingray Energy Services LLC	50.0 %	4,382	5,908	294	218	935	539
Investment in Sturgeon Acquisitions LLC	25.0 %	22,146	22,769	112	(257)	623	(1,316)
Investment in Mammoth Energy Partners LP	30.5 %	120,773	131,630	2,518	3,612	11,527	11,608
Investment in Strike Force Midstream LLC	25.0 %	26,539	—	(99)	—	(40)	—
		$251,309	$ 242,393	$(5,997)	$61,891	$25,576	$57,036

Table of Contents

The tables below summarizes financial information for the Company's equity investments as of September 30, 2016 and December 31, 2015.

Summarized balance sheet information:

	September 30, 2016	December 31, 2015
	(In thousands)	
Current assets	$129,401	$ 105,537
Noncurrent assets	$1,389,258	$ 1,293,925
Current liabilities	$62,882	$ 56,559
Noncurrent liabilities	$91,928	$ 155,995

Summarized results of operations:

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
	(In thousands)			
Gross revenue	$76,627	$100,979	$206,666	$364,669
Net (income) loss	$(35,212)	$10,063	$(9,344)	$(35,359)

Tatex Thailand II, LLC

The Company has an indirect ownership interest in Tatex Thailand II, LLC (“Tatex II”). Tatex II holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC (“APICO”), an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately 243,000 acres which includes the Phu Horm Field. During the nine months ended September 30, 2016, the Company received $0.4 million in distributions from Tatex II.

Tatex Thailand III, LLC

The Company has an ownership interest in Tatex Thailand III, LLC ("Tatex III"). Tatex III previously owned a concession covering approximately 245,000 acres in Southeast Asia. As of December 31, 2014, the Company reviewed its investment in Tatex III and made the decision to allow the concession to expire in January 2015. As such, the Company fully impaired the asset as of December 31, 2014.

Grizzly Oil Sands ULC

The Company, through its wholly owned subsidiary Grizzly Holdings Inc. ("Grizzly Holdings"), owns an interest in Grizzly Oil Sands ULC ("Grizzly"), a Canadian unlimited liability company. The remaining interest in Grizzly is owned by Grizzly Oil Sands Inc. ("Oil Sands"). As of September 30, 2016, Grizzly had approximately 830,000 acres under lease in the Athabasca and Peace River oil sands regions of Alberta, Canada. Initiation of steam injection at its first project, Algar Lake Phase 1, commenced in January 2014 and first bitumen production was achieved during the second quarter of 2014. In April 2015, Grizzly determined to cease bitumen production at its Algar Lake facility due to the level of commodity prices. Grizzly continues to monitor market conditions as it assesses future plans for the facility. The Company reviewed its investment in Grizzly at March 31, 2016 for impairment based on FASB ASC 323 due to certain qualitative factors and engaged an independent third party to assist management in determining fair value calculations of its investment. As a result of the calculated fair values and other qualitative factors, the Company concluded that an other than temporary impairment was required under FASB ASC 323, resulting in an impairment loss of $23.1 million for the three months ended March 31, 2016, which is included in (income) loss from equity method investments in the consolidated statements of operations. As of and during the period ended September 30, 2016, commodity prices had increased as compared to the quarter ended March 31, 2016, and there were no impairment indicators that required further evaluation for impairment. If commodity prices decline in the future, however, further impairment of the investment in Grizzly may be necessary. During the nine months ended September 30, 2016, Gulfport paid $14.5 million in cash calls. Grizzly’s functional currency is the Canadian dollar. The Company's investment in Grizzly was decreased by $1.4 million as a result of a foreign currency translation loss and increased by $8.3 million as a result of a foreign currency translation gain for the three and nine months ended

September 30, 2016,

10

respectively. The Company's investment in Grizzly was decreased by $11.6 million and $23.3 million as a result of a foreign currency translation loss for the three and nine months ended September 30, 2015, respectively.

Effective October 5, 2012, Grizzly entered into a $125.0 million revolving credit facility, of which Grizzly paid the outstanding balance in full in July 2016. Gulfport paid its share of this amount on June 30, 2016.

Timber Wolf Terminals LLC

During 2012, the Company invested in Timber Wolf Terminals LLC (“Timber Wolf”). Timber Wolf was formed to operate a crude/condensate terminal and a sand transloading facility in Ohio.

Windsor Midstream LLC

During 2012, the Company purchased an ownership interest in Windsor Midstream LLC (“Midstream”). Midstream owned a 28.4% interest in Coronado Midstream LLC ("Coronado"), a gas processing plant in West Texas. In March 2015, Coronado was sold to Enlink Midstream Partners, LP ("EnLink") for proceeds of approximately $600.0 million, consisting of cash and units representing a limited partnership interest in Enlink. Midstream recorded an $81.6 million gain on the sale of its investment in Coronado. The Company received $14.2 million in distributions from Midstream during the nine months ended September 30, 2016.

Stingray Cementing LLC

During 2012, the Company invested in Stingray Cementing LLC ("Stingray Cementing"). Stingray Cementing provides well cementing services. The (income) loss from equity method investments presented in the table above reflects any intercompany profit eliminations.

Blackhawk Midstream LLC

During 2012, the Company invested in Blackhawk Midstream LLC ("Blackhawk"). Blackhawk was formed to coordinate gathering, compression, processing and marketing activities for the Company in connection with the development of its Utica Shale acreage. On January 28, 2014, Blackhawk completed the sale of its equity interests in Ohio Gathering Company, LLC and Ohio Condensate Company, LLC for a purchase price of $190.0 million, of which $14.3 million was placed in escrow. During the first quarter of 2015, the Company received net proceeds of approximately $7.2 million from the release of escrow from the Blackhawk sale, which is included in (income) loss from equity method investments in the consolidated statements of operations.

Stingray Energy Services LLC

During 2013, the Company invested in Stingray Energy Services LLC ("Stingray Energy"). Stingray Energy provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites. The (income) loss from equity method investments presented in the table above reflects any intercompany profit eliminations.

Sturgeon Acquisitions LLC

During 2014, the Company invested $20.7 million and received an ownership interest of 25% in Sturgeon Acquisitions LLC ("Sturgeon"). Sturgeon owns and operates sand mines that produce hydraulic fracturing grade sand.

Mammoth Energy Partners LP

In the fourth quarter of 2014, the Company contributed its investments in four entities to Mammoth Energy Partners LP ("Mammoth") for a 30.5% interest in this entity. Mammoth originally intended to pursue its initial public offering in 2014 or 2015; however, due to low commodity prices, the offering was postponed. In October 2016, Mammoth became a wholly-owned subsidiary of Mammoth Energy Services, Inc. ("Mammoth Energy"), and Mammoth Energy closed its initial public offering (the "IPO"). Upon completion of the IPO, the Company owned 24.2% of the outstanding common stock of Mammoth Energy. See Note 16 for further discussion of the initial public offering. The Company reviewed its investment in Mammoth at September 30, 2016 and determined no impairment was needed. If commodity prices decline in the future, an impairment of the investment in Mammoth may result. The Company's investment in Mammoth was increased by a $0.2 million foreign

Table of Contents

currency gain and decreased by a $1.1 million foreign currency loss resulting from Mammoth's foreign subsidiary for the three and nine months ended September 30, 2016, respectively. The (income) loss from equity method investments presented in the table above reflects any intercompany profit eliminations.

Strike Force Midstream LLC

In February 2016, the Company, through its wholly owned subsidiary Gulfport Midstream Holdings, LLC ("Midstream Holdings"), entered into an agreement with Rice Midstream Holdings LLC ("Rice"), a subsidiary of Rice Energy Inc., to develop natural gas gathering assets in eastern Belmont County and Monroe County, Ohio (the "dedicated areas"). The Company contributed certain gathering assets for a 25% interest in the newly formed entity called Strike Force Midstream LLC ("Strike Force"). Rice acts as operator and owns the remaining 75% interest in Strike Force. Construction of the gathering assets, which is underway, is expected to provide gathering services for Gulfport operated wells and connectivity of existing dry gas gathering systems. During the nine months ended September 30, 2016, Gulfport paid $4.0 million in cash calls to Strike Force.

The Company accounted for its contribution to Strike Force at fair value under applicable codification guidance. The Company estimated the fair market value of its investment in Strike Force as of the contribution date using the discounted cash flow method under the income approach, based on an independently prepared valuation of the contributed assets. The fair market value was reduced by a discount factor for the lack of marketability due to the Company's minority interest, resulting in a fair value of $22.5 million for the Company's 25% interest. The fair value of the assets contributed was estimated using assumptions that represent Level 3 inputs. See "Note 12 - Fair Value Measurements" for additional discussion of the measurement inputs. The Company has elected to report its proportionate share of Strike Force's earnings on a one-quarter lag as permitted under FASB ASC 323. The (income) loss from equity method investments presented in the table above reflects any intercompany profit eliminations.

4. VARIABLE INTEREST ENTITIES

As of September 30, 2016, the Company held variable interests in the following variable interest entities ("VIEs"), but was not the primary beneficiary: Mammoth, Stingray Energy, Stingray Cementing, Sturgeon, Midstream and Timber Wolf. These entities have governing provisions that are the functional equivalent of a limited partnership and are considered VIEs because the limited partners or non-managing members lack substantive kick-out or participating rights which causes the equity owners, as a group, to lack a controlling financial interest. The Company is a limited partner or non-managing member in each of these VIEs and is not the primary beneficiary because it does not have a controlling financial interest. The general partner or managing member has power to direct the activities that most significantly impact the VIEs’ economic performance. The Company also held a variable interest in Strike Force due to the fact that it does not have sufficient equity capital at risk. The Company is not the primary beneficiary of this entity. The Company accounts for its investment in these VIEs following the equity method of accounting. The carrying amounts of the Company’s equity investments are classified as other non-current assets on the accompanying consolidated balance sheets. The Company’s maximum exposure to loss as a result of its involvement with these VIEs is based on the Company’s capital contributions and the economic performance of the VIEs, and is equal to the carrying value of the Company’s investments which is the maximum loss the Company could be required to record in the consolidated statements of operations. See Note 3 for further discussion of these entities, including the carrying amounts of each investment.

5. OTHER ASSETS

Other assets consist of the following as of September 30, 2016 and December 31, 2015:

Table of Contents

	September 30, 2016	December 31, 2015
	(In thousands)	
Plugging and abandonment escrow account on the WCBB properties (Note 10)	$3,081	$ 3,089
Certificates of Deposit securing letter of credit	276	276
Prepaid drilling costs	—	58
Loan commitment fees	2,070	2,870
Deposits	34	34
Other	51	37
	$5,512	$ 6,364

6. LONG-TERM DEBT

Long-term debt consisted of the following items as of September 30, 2016 and December 31, 2015:

	September 30, 2016	December 31, 2015
	(In thousands)	
Revolving credit agreement (1)	$—	$ —
Building loan (2)	—	1,653
7.75% senior unsecured notes due 2020 (3)	600,000	600,000
6.625% senior unsecured notes due 2023 (4)	350,000	350,000
Net unamortized original issue premium, net (5)	10,777	12,493
Net unamortized debt issuance costs (6)	(16,006)	(17,883)
Construction loan (7)	16,499	—
Less: current maturities of long term debt	(220)	(179)
Debt reflected as long term	$961,050	$ 946,084

The Company capitalized approximately $4.7 million and $7.7 million in interest expense to undeveloped oil and natural gas properties during the three and nine months ended September 30, 2016, respectively. The Company capitalized approximately $3.6 million and $12.0 million in interest expense to undeveloped oil and natural gas properties during the three and nine months ended September 30, 2015, respectively. During the three and nine months ended September 30, 2016, the Company also capitalized approximately $0.5 million and $1.2 million, respectively, in interest expense related to building construction.

(1) The Company has entered into a senior secured revolving credit facility, as amended, with The Bank of Nova Scotia, as the lead arranger and administrative agent and certain lenders from time to time party thereto. The credit agreement provides for a maximum facility amount of $1.5 billion and matures on June 6, 2018. On February 19, 2016, the Company further amended its revolving credit facility to, among other things, (a) increase the basket for unsecured debt issuances to $1.4 billion from $1.2 billion (of which $950 million was then outstanding), (b) reaffirm the Company's borrowing base of $700.0 million, and (c) increase the percentage of projected oil and gas production that may be hedged by the Company during 2016. As of September 30, 2016, no balance was outstanding under this revolving credit facility and total funds available for borrowing, after giving effect to an aggregate of $207.0 million of letters of credit, were $493.0 million. This facility is secured by substantially all of the Company's assets. The wholly-owned subsidiaries of the Company guarantee the obligations under the revolving credit facility.

Advances under this revolving credit facility may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 0.50% to 1.50%, plus (2) the highest of: (a) the federal funds rate plus 0.50%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its "prime rate," and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 1.50% to 2.50%, plus (2) the London interbank offered rate that appears on pages LIBOR01 or LIBOR02 of the Reuters screen that displays such rate for deposits in U.S. dollars, or, if such rate is not available, the rate as administered by ICE Benchmark

Administration (or any other person that takes over administration of such rate) per annum equal to the offered rate on such other page or other service that displays an average

13

London interbank offered rate as administered by ICE Benchmark Administration (or any other person that takes over the administration of such rate) for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the “London Interbank Offered Rate” for deposits in U.S. dollars.

The Company's revolving credit facility contains customary negative covenants including, but not limited to, restrictions on the Company's and its subsidiaries' ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in this revolving credit facility. The Company's revolving credit facility also contains certain affirmative covenants, including, but not limited to the following financial covenants: (1) the ratio of net funded debt to EBITDAX (net income, excluding (i) any non-cash revenue or expense associated with swap contracts resulting from ASC 815 and (ii) any cash or non-cash revenue or expense attributable to minority investment plus without duplication and, in the case of expenses, to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) exploration costs deducted in determining net income under successful efforts accounting, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offerings (provided that expenses related to any unsuccessful dispositions will be limited to $3.0 million in the aggregate) for a twelve-month period may not be greater than 4.00 to 1.00; and (2) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. The Company was in compliance with these financial covenants at September 30, 2016.

(2) In March 2011, the Company refinanced the $2.4 million then outstanding under its previous building loan for the office building it occupies in Oklahoma City, Oklahoma. This loan agreement, as subsequently amended, bore interest at the rate of 4.00% per annum, required monthly interest and principal payments of approximately $20,000, was collateralized by the Oklahoma City office building and associated land and had a maturity date of December 2018. The Company paid the balance of the loan in full in February 2016.

(3) On October 17, 2012, the Company issued $250.0 million in aggregate principal amount of senior unsecured notes due 2020 (the "October Notes") under an indenture among the Company, its subsidiary guarantors and Wells Fargo Bank, National Association, as the trustee (the "senior note indenture"). On December 21, 2012, the Company issued an additional $50.0 million in aggregate principal amount of senior unsecured notes due 2020 (the "December Notes") as additional securities under the senior note indenture. On August 18, 2014, the Company issued an additional $300.0 million in aggregate principal amount of senior unsecured notes due 2020 (the "August Notes"). The August Notes were issued as additional securities under the senior note indenture. The October Notes, December Notes and the August Notes are collectively referred to as the "2020 Notes."

In connection with the issuance of the 2020 Notes, the Company and the subsidiary guarantors entered into a registration rights agreement with the initial purchasers, pursuant to which the Company and the subsidiary guarantors agreed to file a registration statement with respect to an offering to exchange the 2020 Notes for a new issue of substantially identical debt securities registered under the Securities Act. The exchange offer for the October Notes and the December Notes was completed in October 2013 and the exchange offer for the August Note was completed in March 2015.

Under the senior note indenture relating to the 2020 Notes, interest on the 2020 Notes accrues at a rate of 7.75% per annum on the outstanding principal amount from October 17, 2012, payable semi-annually on May 1 and November 1 of each year, commencing on May 1, 2013. The 2020 Notes are the Company's senior unsecured obligations and rank equally in the right of payment with all of the Company's other senior indebtedness and senior in right of payment to any future subordinated indebtedness. All of the Company's existing and future restricted subsidiaries that guarantee the Company's secured revolving credit facility or certain other debt guarantee the 2020 Notes; provided, however, that the 2020 Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of the Company's future unrestricted subsidiaries. The Company may redeem some or all of the 2020 Notes at any time on or after November 1, 2016, at the redemption prices listed in the senior note indenture. Prior to November 1, 2016, the Company may redeem the 2020 Notes at a price equal to 100% of the principal amount plus a “make-whole” premium. In addition, prior to November 1, 2015, the Company may redeem up to 35% of the aggregate principal amount of the 2020 Notes with the net proceeds of certain equity offerings, provided that at least 65% of the aggregate principal amount of the 2020 Notes initially issued remains outstanding immediately after such redemption. See Note 16, Subsequent Events - "Tender Offer and Redemption - Existing 2020 Notes."

(4) On April 21, 2015, the Company issued $350.0 million in aggregate principal amount of 6.625% Senior Notes due 2023 (the "2023 Notes" and, together with the "2020 Notes," the "Notes") to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act (the "2023 Notes Offering"). The Company received net proceeds of approximately $343.6 million after initial purchaser discounts and commissions and estimated offering expenses.

The 2023 notes were issued under an indenture, dated as of April 21, 2015, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee. Pursuant to the indenture relating to the 2023 Notes, interest on the 2023 Notes will accrue at a rate of 6.625% per annum on the outstanding principal amount thereof from April 21, 2015, payable semi-annually on May 1 and November 1 of each year, commencing on November 1, 2015. The 2023 Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of the Company's future unrestricted subsidiaries.

In connection with the 2023 Notes Offering, the Company and its subsidiary guarantors entered into a registration rights agreement, dated as of April 21, 2015, pursuant to which the Company agreed to file a registration statement with respect to an offer to exchange the 2023 Notes for a new issue of substantially identical debt securities registered under the Securities Act. The exchange offer for the 2023 Notes was completed on October 13, 2015.

(5) The October Notes were issued at a price of 98.534% resulting in a gross discount of $3.7 million and an effective rate of 8.000%. The December Notes were issued at a price of 101.000% resulting in a gross premium of $0.5 million and an effective rate of 7.531%. The August Notes were issued at a price of 106.000% resulting in a gross premium of $18.0 million and an effective rate of 6.561%. The April Notes were issued at par. The premium and discount are being amortized using the effective interest method.

(6) In accordance with Accounting Standards Update ("ASU") 2015-03, loan issuance costs related to the Notes have been presented as a reduction to the Notes. At September 30, 2016, total unamortized debt issuance costs were $4.4 million for the October Notes, $1.0 million for the December Notes, $4.3 million for the August Notes and $6.2 million for the April Notes. At September 30, 2016, total unamortized debt issuance costs were $0.1 million for the Construction Loan (as defined below).

(7) On June 4, 2015, the Company entered into a construction loan agreement (the "Construction Loan") with InterBank for the construction of a new corporate headquarters in Oklahoma City. The Construction Loan allows for a maximum principal amount of $24.5 million and requires the Company to fund 30% of the estimated cost of the construction before any funds can be drawn, which occurred in January 2016. Interest accrues daily on the outstanding principal balance at a fixed rate of 4.50% per annum and is payable on the last day of the month through May 31, 2017. Monthly interest and principal payments are due beginning June 30, 2017, with the final payment due June 4, 2025. At September 30, 2016, the total borrowings under the Construction Loan were approximately $16.5 million.

7. COMMON STOCK AND CHANGES IN CAPITALIZATION

Sale of Common Stock

On March 15, 2016, the Company issued 16,905,000 shares of its common stock in an underwritten public offering (which included 2,205,000 shares sold pursuant to an option to purchase additional shares of the Company's common stock granted by the Company to, and exercised in full by, the underwriters). The net proceeds from this equity offering were approximately $411.7 million, after underwriting discounts and commissions and offering expenses. The Company intends to use the net proceeds from this offering primarily to fund a portion of its 2017 capital development plan and for general corporate purposes.

8. STOCK-BASED COMPENSATION

During the three and nine months ended September 30, 2016 , the Company’s stock-based compensation cost was $3.0 million and $9.6 million, respectively, of which the Company capitalized $1.2 million and $3.8 million, respectively, relating to its exploration and development efforts. During the three and nine months ended September 30, 2015, the Company’s stock-based compensation cost was $3.9 million and $10.6 million, respectively, of which the Company capitalized $1.5 million and $4.2 million, respectively, relating to its exploration and development efforts.

The following table summarizes restricted stock activity for the nine months ended September 30, 2016:

15

Table of Contents

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of January 1, 2016	484,239	$ 43.51
Granted	446,291	27.80
Vested	(226,283)	43.26
Forfeited	(8,998)	34.59
Unvested shares as of September 30, 2016	695,249	$ 33.62

Unrecognized compensation expense as of September 30, 2016 related to restricted shares was $18.4 million. The expense is expected to be recognized over a weighted average period of 1.72 years.

Table of Contents

9. EARNINGS PER SHARE

Reconciliations of the components of basic and diluted net loss per common share are presented in the tables below:

	Three months ended September 30,					
	2016			2015		
	Loss	Shares	Per Share	Loss	Shares	Per Share
	(In thousands, except share data)					
Basic:						
Net loss	$(157,296)	125,408,866	$(1.25)	$(388,209)	108,217,062	$(3.59)
Effect of dilutive securities:						
Stock options and awards	—	—		—	—	
Diluted:		—				
Net loss	$(157,296)	125,408,866	$(1.25)	$(388,209)	108,217,062	$(3.59)

	Nine months ended September 30,					
	2016			2015		
	Loss	Shares	Per Share	Loss	Shares	Per Share
	(In thousands, except share data)					
Basic:						
Net loss	$(739,339)	120,771,046	$(6.12)	$(394,015)	96,935,897	$(4.06)
Effect of dilutive securities:						
Stock options and awards	—	—		—	—	
Diluted:		—				
Net loss	$(739,339)	120,771,046	$(6.12)	$(394,015)	96,935,897	$(4.06)

There were 603,068 and 598,753 shares of common stock that were considered anti-dilutive for the three and nine months ended September 30, 2016, respectively. There were 510,605 and 462,801 shares of common stock that were considered anti-dilutive for the three and nine months ended September 30, 2015, respectively.

Table of Contents

10. COMMITMENTS AND CONTINGENCIES

Plugging and Abandonment Funds

In connection with the Company's acquisition in 1997 of the remaining 50% interest in its WCBB properties, the Company assumed the seller’s (Chevron) obligation to contribute approximately $18,000 per month through March 2004 to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until the Company's abandonment obligations to Chevron have been fulfilled. Beginning in 2009, the Company could access the trust for use in plugging and abandonment charges associated with the property, although it has not yet done so. As of September 30, 2016, the plugging and abandonment trust totaled approximately $3.1 million. At September 30, 2016, the Company had plugged 483 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its current minimum plugging obligation.

Operating Leases

The Company leases office facilities under non-cancellable operating leases exceeding one year. Future minimum lease commitments under these leases at September 30, 2016 were as follows:

	(In thousands)
Remaining 2016	$ 184
2017	583
2018	54
Total	$ 821

Other Commitments

Effective October 1, 2014 and subsequently amended on November 3, 2015, the Company entered into a Sand Supply Agreement with Muskie Proppant LLC ("Muskie") that expires on September 30, 2018. Pursuant to this agreement, the Company has agreed to purchase annual and monthly amounts of proppant sand subject to exceptions specified in the agreement at agreed pricing, plus agreed costs and expenses. Failure by either Muskie or the Company to deliver or accept the minimum monthly amount results in damages calculated per ton based on the difference between the monthly obligation amount and the amount actually delivered or accepted, as applicable. The Company incurred $0.2 million and $2.1 million related to non-utilization fees during the three and nine months ended September 30, 2016, respectively.

Effective October 1, 2014, the Company entered into an Amended and Restated Master Services Agreement for pressure pumping services with Stingray Pressure Pumping LLC ("Stingray Pressure") that expires on September 30, 2018. Pursuant to this agreement, Stingray Pressure has agreed to provide hydraulic fracturing, stimulation and related completion and rework services to the Company and the Company has agreed to pay Stingray Pressure a monthly service fee plus the associated costs of the services provided. On February 18, 2016, effective January 1, 2016, the Company amended its Master Services Agreement with Stingray Pressure. The amendment adjusted the amount of service fees payable for the period from January 1, 2016 through September 30, 2016.

Future minimum commitments under these agreements at September 30, 2016 are as follows:

	(In thousands)
Remaining 2016	$ 13,110
2017	52,440
2018	39,330
Total	$ 104,880

Litigation

In two separate complaints, one filed by the State of Louisiana and the Parish of Cameron in the 38th Judicial District Court for the Parish of Cameron on February 9, 2016 and the other filed by the State of Louisiana and the District Attorney for

Table of Contents

the 15th Judicial District of the State of Louisiana in the 15th Judicial District Court for the Parish of Vermillion on July 29, 2016, the Company was named as a defendant, among 26 oil and gas companies, in the Cameron Parish complaint and among more than 40 oil and gas companies in the Vermillion Parish complaint (the "Complaints"). The Complaints were filed under the State and Local Coastal Resources Management Act of 1978, as amended, and the rules, regulations, orders and ordinances adopted thereunder, which the Company referred to collectively as the CZM Laws, and allege that certain of the defendants' oil and gas exploration, production and transportation operations associated with the development of the East Hackberry and West Hackberry oil and gas fields, in the case of the Cameron Parish complaint, and the Tigre Lagoon oil and gas field, in the case of the Vermillion Parish complaint, were conducted in violation of the CZM Laws. The Complaints allege that such activities caused substantial damage to land and waterbodies located in the coastal zone of the relevant Parish, including due to defendants' design, construction and use of waste pits and the alleged failure to properly close the waste pits and to clear, re-vegetate, detoxify and return the property affected to its original condition, as well as the defendants' alleged discharge of waste into the coastal zone. The Complaints also allege that the defendants' oil and gas activities have resulted in the dredging of numerous canals, which had a direct and significant impact on the state coastal waters within the relevant Parish and that the defendants, among other things, failed to design, construct and maintain these canals using the best practical techniques to prevent bank slumping, erosion and saltwater intrusion and to minimize the potential for inland movement of storm-generated surges, which activities allegedly have resulted in the erosion of marshes and the degradation of terrestrial and aquatic life therein. The Complaints also allege that the defendants failed to re-vegetate, refill, clean, detoxify and otherwise restore these canals to their original condition. In these two petitions, the plaintiffs seek damages and other appropriate relief under the CZM Laws, including the payment of costs necessary to clear, re-vegetate, detoxify and otherwise restore the affected coastal zone of the relevant Parish to its original condition, actual restoration of such coastal zone to its original condition, and the payment of reasonable attorney fees and legal expenses and pre-judgment and post judgment interest.

The Company was served with the Cameron complaint in early May 2016 and with the Vermillion complaint in early September 2016. The Louisiana Attorney General and the Louisiana Department of Natural Resources intervened in both the Cameron Parish suit and the Vermillion Parish suit. Shortly after the Complaints were filed, certain defendants removed the cases to the lawsuit to the United States District Court for the Western District of Louisiana. In both cases, the plaintiffs have filed a motion to remand, but both Courts have stayed further proceedings on the motions to remand pending a ruling from the United States Court of Appeals, Fifth Circuit on similar jurisdictional issues in another matter. The plaintiffs have granted all defendants an extension of time to file responsive pleadings to the Complaints until the District Courts rule on the motions to remand. The Company has not had the opportunity to evaluate the applicability of the allegations made in such complaints to their operations. Due to the early stages of these matters, management cannot determine the amount of loss, if any, that may result.

In addition, due to the nature of the Company's business, it is, from time to time, involved in routine litigation or subject to disputes or claims related to its business activities, including workers' compensation claims and employment related disputes. In the opinion of the Company's management, none of the pending litigation, disputes or claims against the Company, if decided adversely, will have a material adverse effect on its financial condition, cash flows or results of operations.

11. DERIVATIVE INSTRUMENTS

Oil, Natural Gas and Natural Gas Liquids Derivative Instruments

The Company seeks to reduce its exposure to unfavorable changes in oil, natural gas and natural gas liquids prices, which are subject to significant and often volatile fluctuation, by entering into fixed over-the-counter fixed price swaps, basis swaps and various types of option contracts. These contracts allow the Company to predict with greater certainty the effective oil, natural gas and natural gas liquids prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, the Company will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production.

Fixed price swaps are settled monthly based on differences between the fixed price specified in the contract and the referenced settlement price. When the referenced settlement price is less than the price specified in the contract, the Company receives an amount from the counterparty based on the price difference multiplied by the volume. Similarly, when the referenced settlement price exceeds the price specified in the contract, the Company pays the counterparty an amount based on the price difference multiplied by the volume. The prices contained in these fixed price swaps are based on Argus Louisiana Light Sweet Crude for oil, the NYMEX Henry Hub for natural gas and Mont Belvieu for propane. Below is a summary of the Company's open fixed price swap positions as of September 30, 2016.

	Location	Daily Volume (Bbls/day)	Weighted Average Price
October 2016 - June 2017	ARGUS LLS	2,000	$ 51.10

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
October 2016	NYMEX Henry Hub	570,000	$ 3.05
November 2016 - December 2016	NYMEX Henry Hub	525,000	$ 3.18
January 2017 - February 2017	NYMEX Henry Hub	442,500	$ 3.14
March 2017	NYMEX Henry Hub	422,500	$ 3.13
April 2017 - June 2017	NYMEX Henry Hub	367,500	$ 3.15
July 2017 - October 2017	NYMEX Henry Hub	305,000	$ 2.99
November 2017 - December 2017	NYMEX Henry Hub	435,000	$ 3.06
January 2018 - March 2018	NYMEX Henry Hub	290,000	$ 3.10
April 2018 - December 2018	NYMEX Henry Hub	160,000	$ 3.01
January 2019 - March 2019	NYMEX Henry Hub	20,000	$ 3.37

	Location	Daily Volume (Bbls/day)	Weighted Average Price
October 2016 - December 2016	Mont Belvieu	1,500	$ 19.95

The Company sold call options and used the associated premiums to enhance the fixed price for a portion of the fixed price natural gas swaps listed above. Each short call option has an established ceiling price. When the referenced settlement price is above the price ceiling established by these short call options, the Company pays its counterparty an amount equal to the difference between the referenced settlement price and the price ceiling multiplied by the hedged contract volume.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
January 2017 - March 2017	NYMEX Henry Hub	105,000	$ 3.27
April 2017 - December 2017	NYMEX Henry Hub	125,000	$ 3.21
January 2018 - March 2018	NYMEX Henry Hub	20,000	$ 2.91

For a portion of the combined natural gas derivative instruments containing fixed price swaps and sold call options, the counterparty has an option to extend the original terms an additional twelve months for the period January 2017 through December 2017. The option to extend the terms expires in December 2016. If executed, the Company would have additional fixed price swaps for 30,000 MMBtu per day at a weighted average price of $3.33 per MMBtu and additional short call options for 30,000 MMBtu per day at a weighted average ceiling price of $3.33 per MMBtu.

In addition, the Company has entered into natural gas basis swap positions, which settle on the pricing index to basis differential of MichCon or Tetco M2 to the NYMEX Henry Hub natural gas price. As of September 30, 2016, the Company had the following natural gas basis swap positions for MichCon and Tetco M2, respectively.

	Location	Daily Volume (MMBtu/day)	Hedged Differential
October 2016 - December 2016	MichCon	40,000	$ 0.02
November 2016 - March 2017	Tetco M2	50,000	$ (0.59)

Balance Sheet Presentation

The Company reports the fair value of derivative instruments on the consolidated balance sheets as derivative instruments under current assets, noncurrent assets, current liabilities and noncurrent liabilities on a gross basis. The Company determines the current and noncurrent classification based on the timing of expected future cash flows of individual trades. The following table presents the fair value of the Company's derivative instruments on a gross basis at September 30, 2016:

	(In thousands)
Short-term derivative instruments - asset	$ 39,363
Long-term derivative instruments - asset	$ 15,262
Short-term derivative instruments - liability	$ 37,220
Long-term derivative instruments - liability	$ 14,907

Gains and Losses

For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income (loss) until the hedged item is recognized in earnings. The Company has no cash flow hedges in place for the three and nine months ended September 30, 2016 and 2015, as all fixed price swaps, swaptions and basis swaps had either been deemed ineffective at their inception or had been accounted for using the mark-to-market accounting method.

The following table presents the net gain and loss recognized in gas sales, oil and condensate sales and natural gas liquids sales in the accompanying consolidated statements of operations for the three and nine months ended September 30, 2016 and 2015.

	Net gain (loss) on derivative instruments			
	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
	(In thousands)			
Gas sales	$33,167	$79,684	$(43,454)	$118,137
Oil and condensate sales	1,708	12,072	362	13,641
Natural gas liquids sales	406	—	(1,284)	—
Total net gain (loss)	$35,281	$91,756	$(44,376)	$131,778

Concentration of Credit Risk

By using derivative instruments that are not traded on an exchange, the Company is exposed to the credit risk of its counterparties. Credit risk is the risk of loss from counterparties not performing under the terms of the derivative instrument. When the fair value of a derivative instrument is positive, the counterparty is expected to owe the Company, which creates credit risk. To minimize the credit risk in derivative instruments, it is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The Company's derivative contracts are with multiple counterparties to lessen its exposure to any individual counterparty. Additionally, the Company uses master netting agreements to minimize credit risk exposure. The creditworthiness of the Company's counterparties is subject to periodic review. Other than as provided by the Company's revolving credit facility, the Company is not required to provide credit support or collateral to any of its counterparties under its derivative instruments, nor are the counterparties required to provide credit support to the Company.

12. FAIR VALUE MEASUREMENTS

The Company records certain financial and non-financial assets and liabilities on the balance sheet at fair value in accordance with FASB ASC 820, "Fair Value Measurement and Disclosures" ("FASB ASC 820"). FASB ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. The statement establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The statement requires fair value measurements be classified and disclosed in one of the following categories:

Level 1 – Quoted prices in active markets for identical assets and liabilities.

Table of Contents

Level 2 – Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active and model-derived valuations whose inputs are observable or whose significant value drivers are observable.
Level 3 – Significant inputs to the valuation model are unobservable.
Valuation techniques that maximize the use of observable inputs are favored. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter.
The following tables summarize the Company's financial and non-financial assets and liabilities by FASB ASC 820 valuation level as of September 30, 2016:

	September 30, 2016		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Derivative Instruments	$ —	$ 54,625	$ —
Liabilities:			
Derivative Instruments	$ —	$ 52,127	$ —

The Company estimates the fair value of all derivative instruments industry-standard models that considered various assumptions including current market and contractual prices for the underlying instruments, implied volatility, time value, nonperformance risk, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be supported by observable data.
The estimated fair values of proved oil and gas properties assumed in business combinations are based on a discounted cash flow model and market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk-adjusted discount rates. The estimated fair values of unevaluated oil and gas properties was based on geological studies, historical well performance, location and applicable mineral lease terms. Based on the unobservable nature of certain of the inputs, the estimated fair value of the oil and gas properties assumed is deemed to use Level 3 inputs. See Note 1 for further discussion of the Company's acquisitions.
The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, Asset Retirement and Environmental Obligations ("FASB ASC 410"). The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 2 for further discussion of the Company's asset retirement obligations. Asset retirement obligations incurred during the nine months ended September 30, 2016 were approximately $6.7 million.
Due to the unobservable nature of the inputs, the fair value of the Company's investment in Grizzly was estimated using assumptions that represent Level 3 inputs. The Company estimated the fair value of the investment as of March 31, 2016 to be approximately $39.1 million. See Note 3 for further discussion of the Company's investment in Grizzly.
Due to the unobservable nature of the inputs, the fair value of the Company's investment in Strike Force was estimated using assumptions that represent Level 3 inputs. The Company's estimated fair value of the investment as of the February 1, 2016 contribution date was $22.5 million. See Note 3 for further discussion of the Company's contribution to Strike Force.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS

Table of Contents

The carrying amounts on the accompanying consolidated balance sheet for cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and current debt are carried at cost, which approximates market value due to their short-term nature. Long-term debt related to the Construction Loan is carried at cost, which approximates market value based on the borrowing rates currently available to the Company with similar terms and maturities.

At September 30, 2016, the carrying value of the outstanding debt represented by the Notes was approximately $944.9 million, including the remaining unamortized discount of approximately $2.1 million related to the October Notes, the remaining unamortized premium of approximately $0.3 million related to the December Notes and $12.6 million related to the August Notes. Also, included in the carrying value of the Notes is unamortized debt issuance cost of approximately $4.4 million related to the October Notes, approximately $1.0 million related to the December Notes, approximately $4.3 million related to the August Notes and approximately $6.2 million related to the 2023 Notes. Based on the quoted market price, the fair value of the Notes was determined to be approximately $984.0 million at September 30, 2016. See also Note 16, Subsequent Events - "Tender Offer and Redemption - Existing 2020 Notes."

14. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

On October 17, 2012, December 21, 2012 and August 18, 2014, the Company issued an aggregate of $600.0 million principal amount of its 7.75% Senior Notes. The October Notes, December Notes, and the August Notes are collectively referred to as the "2020 Notes". The 2020 Notes are guaranteed on a senior unsecured basis by all existing consolidated subsidiaries that guarantee the Company's secured revolving credit facility or certain other debt (the "Guarantors"). The 2020 Notes are not guaranteed by Grizzly Holdings, Inc. (the "Non-Guarantor"). The Guarantors are 100% owned by Gulfport (the "Parent"), and the guarantees are full, unconditional, joint and several. There are no significant restrictions on the ability of the Parent or the Guarantors to obtain funds from each other in the form of a dividend or loan.

In connection with the issuance of the 2020 Notes, the Company and the subsidiary guarantors entered into registration rights agreements with the initial purchasers, pursuant to which the Company and the subsidiary guarantors agreed to file a registration statement with respect to an offer to exchange the 2020 Notes for a new issue of substantially identical debt securities registered under the Securities Act. The exchange offer for the October Notes and December Notes was completed in October 2013 and the exchange offer for the August Notes was completed in March 2015.

On April 21, 2015, the Company issued $350.0 million in aggregate principal amount of 6.625% Senior Notes due 2023 to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. In connection with the 2023 Notes Offering, the Company and its subsidiary guarantors entered into a registration rights agreement, dated as of April 21, 2015, pursuant to which the Company agreed to file a registration statement with respect to an offer to exchange the 2023 Notes for a new issue of substantially identical debt securities registered under the Securities Act. The exchange offer for the 2023 Notes was completed on October 13, 2015.

The following condensed consolidating balance sheets, statements of operations, statements of comprehensive (loss) income and statements of cash flows are provided for the Parent, the Guarantors and the Non-Guarantor and include the consolidating adjustments and eliminations necessary to arrive at the information for the Company on a condensed consolidated basis. The information has been presented using the equity method of accounting for the Parent's ownership of the Guarantors and the Non-Guarantor.

Table of Contents

CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	September 30, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$363,279	$996	$ 1	$—	$364,276
Accounts receivable - oil and gas	133,159	16,283	—	(21,654)	127,788
Accounts receivable - related parties	96	—	—	—	96
Accounts receivable - intercompany	384,280	5,970	—	(390,250)	—
Prepaid expenses and other current assets	10,270	470	—	—	10,740
Short-term derivative instruments	39,363	—	—	—	39,363
Deferred tax asset	38	—	—	—	38
Total current assets	930,485	23,719	1	(411,904)	542,301
Property and equipment:					
Oil and natural gas properties, full-cost accounting	5,425,128	392,059	—	(729)	5,816,458
Other property and equipment	54,417	43	—	—	54,460
Accumulated depletion, depreciation, amortization and impairment	(3,613,630)	(32)	—	—	(3,613,662)
Property and equipment, net	1,865,915	392,070	—	(729)	2,257,256
Other assets:					
Equity investments	241,342	26,540	48,596	(65,169)	251,309
Long-term derivative instruments	15,262	—	—	—	15,262
Deferred tax asset	4,203	—	—	—	4,203
Other assets	5,512	—	—	—	5,512
Total other assets	266,319	26,540	48,596	(65,169)	276,286
Total assets	$3,062,719	$442,329	$ 48,597	$(477,802)	$3,075,843
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$291,217	$40,557	$ 1	$(27,434)	$304,341
Accounts payable - intercompany	—	384,346	125	(384,471)	—
Asset retirement obligation - current	75	—	—	—	75
Short-term derivative instruments	37,220	—	—	—	37,220
Current maturities of long-term debt	220	—	—	—	220
Total current liabilities	328,732	424,903	126	(411,905)	341,856
Long-term derivative instrument	14,907	—	—	—	14,907
Asset retirement obligation - long-term	32,910	—	—	—	32,910
Long-term debt	961,050	—	—	—	961,050
Total liabilities	1,337,599	424,903	126	(411,905)	1,350,723
Stockholders' equity:					
Common stock	1,253	—	—	—	1,253
Paid-in capital	3,245,393	26,822	256,065	(282,887)	3,245,393
Accumulated other comprehensive (loss) income	(50,816)	—	(46,925)	46,925	(50,816)
Retained (deficit) earnings	(1,470,710)	(9,396)	(160,669)	170,065	(1,470,710)
Total stockholders' equity	1,725,120	17,426	48,471	(65,897)	1,725,120
Total liabilities and stockholders' equity	$3,062,719	$442,329	$ 48,597	$(477,802)	$3,075,843

Table of Contents

CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$112,494	$479	$ 1	$—	$112,974
Accounts receivable - oil and gas	72,241	54	—	(423)	71,872
Accounts receivable - related parties	16	—	—	—	16
Accounts receivable - intercompany	326,475	60	—	(326,535)	—
Prepaid expenses and other current assets	3,905	—	—	—	3,905
Short-term derivative instruments	142,794	—	—	—	142,794
Total current assets	657,925	593	1	(326,958)	331,561
Property and equipment:					
Oil and natural gas properties, full-cost accounting,	5,108,258	316,813	—	(729)	5,424,342
Other property and equipment	33,128	43	—	—	33,171
Accumulated depletion, depreciation, amortization and impairment	(2,829,081)	(29)	—	—	(2,829,110)
Property and equipment, net	2,312,305	316,827	—	(729)	2,628,403
Other assets:					
Equity investments	231,892	—	50,644	(40,143)	242,393
Long-term derivative instruments	51,088	—	—	—	51,088
Deferred tax assets	74,925	—	—	—	74,925
Other assets	6,364	—	—	—	6,364
Total other assets	364,269	—	50,644	(40,143)	374,770
Total assets	$3,334,499	$317,420	$ 50,645	$(367,830)	$3,334,734
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$264,893	$527	$ —	$(292)	$265,128
Accounts payable - intercompany	—	326,541	124	(326,665)	—
Asset retirement obligation - current	75	—	—	—	75
Short-term derivative instruments	437	—	—	—	437
Deferred tax liability	50,697	—	—	—	50,697
Current maturities of long-term debt	179	—	—	—	179
Total current liabilities	316,281	327,068	124	(326,957)	316,516
Long-term derivative instrument	6,935	—	—	—	6,935
Asset retirement obligation - long-term	26,362	—	—	—	26,362
Long-term debt, net of current maturities	946,084	—	—	—	946,084
Total liabilities	1,295,662	327,068	124	(326,957)	1,295,897
Stockholders' equity:					
Common stock	1,082	—	—	—	1,082
Paid-in capital	2,824,303	322	241,553	(241,875)	2,824,303
Accumulated other comprehensive (loss) income	(55,177)	—	(55,177)	55,177	(55,177)

Retained (deficit) earnings	(731,371)	(9,970)	(135,855)	145,825	(731,371)
Total stockholders' equity	2,038,837	(9,648)	50,521	(40,873)	2,038,837
Total liabilities and stockholders' equity	$3,334,499	$317,420	$ 50,645	$(367,830)	$3,334,734

25

Table of Contents

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three months ended September 30, 2016				
	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Total revenues	$193,222	$ 464	$ —	$ —	$193,686
Costs and expenses:					
Lease operating expenses	17,283	188	—	—	17,471
Production taxes	3,495	30	—	—	3,525
Midstream gathering and processing	45,385	90	—	—	45,475
Depreciation, depletion, and amortization	62,284	1	—	—	62,285
Impairment of oil and gas properties	212,194	—	—	—	212,194
General and administrative	10,772	(305)	—	—	10,467
Accretion expense	269	—	—	—	269
	351,682	4	—	—	351,686
(LOSS) INCOME FROM OPERATIONS	(158,460)	460	—	—	(158,000)
OTHER (INCOME) EXPENSE:					
Interest expense	12,787	—	—	—	12,787
Interest income	(337)	—	—	—	(337)
Insurance proceeds	(3,750)	—	—	—	(3,750)
(Income) loss from equity method investments and investments in subsidiaries	(6,457)	(99)	364	195	(5,997)
	2,243	(99)	364	195	2,703
(LOSS) INCOME BEFORE INCOME TAXES	(160,703)	559	(364)	(195)	(160,703)
INCOME TAX BENEFIT	(3,407)	—	—	—	(3,407)
NET (LOSS) INCOME	$(157,296)	$ 559	$ (364)	$ (195)	$(157,296)

Table of Contents

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three months ended September 30, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$230,282	$ 287	$ —	$ —	$230,569
Costs and expenses:					
Lease operating expenses	17,358	210	—	—	17,568
Production taxes	3,570	23	—	—	3,593
Midstream gathering and processing	42,139	27	—	—	42,166
Depreciation, depletion, and amortization	90,327	2	—	—	90,329
Impairment of oil and gas properties	594,776	—	—	—	594,776
General and administrative	10,999	6	(4)	—	11,001
Accretion expense	212	—	—	—	212
	759,381	268	(4)	—	759,645
(LOSS) INCOME FROM OPERATIONS	(529,099)	19	4	—	(529,076)
OTHER (INCOME) EXPENSE:					
Interest expense	14,124	—	—	—	14,124
Interest income	(279)	—	—	—	(279)
Loss (income) from equity method investments and investments in subsidiaries	61,868	—	58,653	(58,630)	61,891
	75,713	—	58,653	(58,630)	75,736
(LOSS) INCOME BEFORE INCOME TAXES	(604,812)	19	(58,649)	58,630	(604,812)
INCOME TAX BENEFIT	(216,603)	—	—	—	(216,603)
NET (LOSS) INCOME	$(388,209)	$ 19	$ (58,649)	$ 58,630	$(388,209)

Table of Contents

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Nine months ended September 30, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$321,399	$ 1,098	$ —	$ —	$ 322,497
Costs and expenses:					
Lease operating expenses	48,246	543	—	—	48,789
Production taxes	9,410	82	—	—	9,492
Midstream gathering and processing	122,250	226	—	—	122,476
Depreciation, depletion, and amortization	183,411	3			183,414
Impairment of oil and gas properties	601,806	—	—	—	601,806
General and administrative	33,230	(291)	2	—	32,941
Accretion expense	777	—	—	—	777
	999,130	563	2	—	999,695
(LOSS) INCOME FROM OPERATIONS	(677,731)	535	(2)	—	(677,198)
OTHER (INCOME) EXPENSE:					
Interest expense	44,891	1	—	—	44,892
Interest income	(822)	—	—	—	(822)
Insurance proceeds	(3,750)	—	—	—	(3,750)
Loss (income) from equity method investments and investments in subsidiaries	25,044	(40)	24,812	(24,240)	25,576
	65,363	(39)	24,812	(24,240)	65,896
(LOSS) INCOME BEFORE INCOME TAXES	(743,094)	574	(24,814)	24,240	(743,094)
INCOME TAX BENEFIT	(3,755)	—	—	—	(3,755)
NET (LOSS) INCOME	$(739,339)	$ 574	$ (24,814)	$ 24,240	$(739,339)

Table of Contents

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Nine months ended September 30, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$518,141	$ 1,015	$ —	$ —	$519,156
Costs and expenses:					
Lease operating expenses	50,830	581	—	—	51,411
Production taxes	11,083	80	—	—	11,163
Midstream gathering and processing	100,405	46	—	—	100,451
Depreciation, depletion, and amortization	251,389	4	—	—	251,393
Impairment of oil and gas properties	594,776	—	—	—	594,776
General and administrative	31,248	47	20	—	31,315
Accretion expense	594	—	—	—	594
	1,040,325	758	20	—	1,041,103
(LOSS) INCOME FROM OPERATIONS	(522,184)	257	(20)	—	(521,947)
OTHER (INCOME) EXPENSE:					
Interest expense	34,906	—	—	—	34,906
Interest income	(536)	—	—	—	(536)
Loss (income) from equity method investments and investments in subsidiaries	56,799	—	71,289	(71,052)	57,036
	91,169	—	71,289	(71,052)	91,406
(LOSS) INCOME BEFORE INCOME TAXES	(613,353)	257	(71,309)	71,052	(613,353)
INCOME TAX BENEFIT	(219,338)	—	—	—	(219,338)
NET (LOSS) INCOME	$(394,015)	$ 257	$ (71,309)	$ 71,052	$(394,015)

Table of Contents

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE (LOSS) INCOME
(Amounts in thousands)

	Three months ended September 30, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net (loss) income	$(157,296)	$ 559	$ (364)	$ (195)	$(157,296)
Foreign currency translation adjustment, net of taxes	(4,013)	—	(1,417)	1,417	(4,013)
Other comprehensive (loss) income	(4,013)	—	(1,417)	1,417	(4,013)
Comprehensive (loss) income	$(161,309)	$ 559	$ (1,781)	$ 1,222	$(161,309)

	Three months ended September 30, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net (loss) income	$(388,209)	$ 19	$ (58,649)	$ 58,630	$(388,209)
Foreign currency translation adjustment	(11,538)	—	(11,538)	11,538	(11,538)
Other comprehensive (loss) income	(11,538)	—	(11,538)	11,538	(11,538)
Comprehensive (loss) income	$(399,747)	$ 19	$ (70,187)	$ 70,168	$(399,747)

	Nine months ended September 30, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net (loss) income	$(739,339)	$ 574	$ (24,814)	$ 24,240	$(739,339)
Foreign currency translation adjustment, net of taxes	4,361	—	8,252	(8,252)	4,361
Other comprehensive income (loss)	4,361	—	8,252	(8,252)	4,361
Comprehensive (loss) income	$(734,978)	$ 574	$ (16,562)	$ 15,988	$(734,978)

	Nine months ended September 30, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net (loss) income	$(394,015)	$ 257	$ (71,309)	$ 71,052	$(394,015)
Foreign currency translation adjustment	(23,275)	—	(23,275)	23,275	(23,275)
Other comprehensive (loss) income	(23,275)	—	(23,275)	23,275	(23,275)
Comprehensive (loss) income	$(417,290)	$ 257	$ (94,584)	$ 94,327	$(417,290)

Table of Contents

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Nine months ended September 30, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$244,758	$ 517	$ 3,998	$ (3,998)	$ 245,275
Net cash (used in) provided by investing activities	(420,257)	(26,500)	(18,510)	45,010	(420,257)
Net cash provided by (used in) financing activities	426,284	26,500	14,512	(41,012)	426,284
Net increase in cash and cash equivalents	250,785	517	—	—	251,302
Cash and cash equivalents at beginning of period	112,494	479	1	—	112,974
Cash and cash equivalents at end of period	$363,279	$ 996	$ 1	$ —	$ 364,276

	Nine months ended September 30, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$247,447	$ (12,356)	$ —	$ —	$ 235,091
Net cash (used in) provided by investing activities	(1,385,878)	13,501	(13,837)	13,837	(1,372,377)
Net cash provided by (used in) financing activities	1,223,057	—	13,837	(13,837)	1,223,057
Net increase in cash and cash equivalents	84,626	1,145	—	—	85,771
Cash and cash equivalents at beginning of period	141,535	804	1	—	142,340
Cash and cash equivalents at end of period	$226,161	$ 1,949	$ 1	$ —	$ 228,111

Table of Contents

15. RECENT ACCOUNTING PRONOUNCEMENTS

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers, which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. The core principle of the new standard is for the recognition of revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which the company expects to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. The ASU is effective for annual periods beginning after December 15, 2016, and interim periods within those years, using either a full or a modified retrospective application approach. In July 2015, the FASB decided to defer the effective date by one year (until 2018). The Company is in the process of evaluating the impact of this ASU on its consolidated financial statements.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements - Going Concern (Subtopic 205-40). The new guidance addresses management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and in certain circumstances to provide related footnote disclosures. The standard is effective for periods after December 15, 2016, with early adoption permitted. The Company does not believe that the adoption of this guidance will have a material impact on its consolidated financial statements.

In April 2015, the FASB issued ASU No. 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. This ASU provides additional guidance to reporting entities in evaluating whether certain legal entities, such as limited partnerships, limited liability corporation and securitization structure, should be consolidated. The ASU is considered to be an improvement on current accounting requirements as it reduces the number of existing consolidation models. The ASU is effective for annual and interim periods beginning in 2016 and is required to be adopted using a retrospective or modified retrospective approach, with early adoption permitted. The Company adopted this ASU on January 1, 2016. As a result, certain of the Company's equity investments were determined to be variable interest entites; however, the Company was not required to consolidate these investments.

In April 2015, the FASB issued ASU No. 2015-03, Simplifying the Presentation of Debt Issuance Costs. To simplify the presentation of debt issuance costs, ASU 2015-03 requires that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts. This guidance is effective for periods after December 15, 2015. The Company adopted this guidance effective December 31, 2015, and has reclassified $16.0 million and $17.9 million of debt issuance costs to offset long-term debt at September 30, 2016 and December 31, 2015, respectively, as shown in Note 6.

In September 2015, the FASB issued ASU No. 2015-16, Simplifying the Accounting for Measurement-Period Adjustments. The guidance eliminates the requirement to retrospectively adjust the financial statements for measurement-period adjustments that occur in periods after a business combination is consummated. Measurement period adjustments are calculated as if they were known at the acquisition date, but are recognized in the reporting period in which they are determined. Additional disclosures are required about the impact on current-period income statement line items of adjustments that would have been recognized in prior periods if the prior-period information had been revised. The guidance is effective for periods after December 15, 2015. The Company adopted this guidance in the first quarter of 2016 and there was no impact to its consolidated financial statements.

In November 2015, the FASB issued ASU No. 2015-17, Balance Sheet Classification of Deferred Taxes (Topic 705). Current guidance requires an entity to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified statement of financial position. Deferred tax liabilities and assets are classified as current or noncurrent based on the classification of the related asset or liability for financial reporting. Deferred tax liabilities and assets that are not related to an asset or liability for financial reporting are classified according to the expected reversal date of the temporary difference. To simplify the presentation of deferred income taxes, the amendments in this update require that deferred income tax liabilities and assets be classified as noncurrent in a classified statement of financial position. This guidance is effective for periods after December 15, 2016, with early adoption permitted. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, Leases. The guidance requires the lessee to recognize most leases on the balance sheet thereby resulting in the recognition of lease assets and liability for those leases currently classified as operating leases. The accounting for lessors is largely unchanged. The guidance is effective for periods after December 15,

Table of Contents

2018, with early adoption permitted. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements.

In March 2016, the FASB issued ASU No. 2016-05, Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships. The guidance was issued to clarify that change in the counterparty to a derivative instrument that had been designated as the hedging instrument under Topic 815, does not require designation of that hedging relationship provided that all other hedge accounting criteria continue to be met. This guidance is effective for periods after December 15, 2017, with early adoption permitted. The Company is in the process of evaluating the impact on its consolidated financial statements. The Company does not believe that the adoption of this guidance will have a material impact on its consolidated financial statements because all current derivative instruments are not designated for hedge accounting.

In March 2016, the FASB issued ASU No. 2016-07, Equity Method and Joint Ventures. This guidance simplified current requirements by eliminating the need to retrospectively apply the equity method of accounting upon obtaining significant influence over an investment that it previously accounted for under the cost basis or at fair value. This guidance is effective for periods after December 15, 2016, with early adoption permitted. The Company is in the process of evaluating the impact on its consolidated financial statements. The Company does not believe that the adoption of this guidance will have a material impact on its consolidated financial statements because all current investments are accounted under the equity method investment.

In March 2016, the FASB issued ASU No. 2016-09, Improvements to Employee Share-Based Payment Accounting. This guidance was intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. This guidance is effective for periods after December 15, 2016, with early adoption permitted. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements.

In May 2016, the FASB issued ASU No. 2016-11, Revenue Recognition and Derivatives and Hedging: Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant to Staff Announcements at the March 3, 2016 EITF Meeting. This guidance rescinds SEC Staff Observer comments that are codified in Topic 606, Revenue Recognition, and Topic 932, Extractive Activities--Oil and Gas. This amendment is effective upon adoption of Topic 606. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments. This guidance provides guidance of eight specific cash flow issues. This amendment is effective for periods after December 15, 2017, with early adoption permitted. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements.

16. SUBSEQUENT EVENTS

6.000% Senior Notes due 2024

On October 14, 2016, the Company issued $650.0 million in aggregate principal amount of 6.000% Senior Notes due 2024 (the “2024 Notes”). The 2024 Notes were issued under an indenture, dated as of October 14, 2016, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as the trustee (the “Indenture”), to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, as amended (the “Securities Act”), and to certain non-U.S. persons in accordance with Regulation S under the Securities Act (the “2024 Notes Offering”). Under the Indenture, interest on the 2024 Notes accrues at a rate of 6.000% per annum on the outstanding principal amount thereof from October 14, 2016, payable semi-annually on April 15 and October 15 of each year, commencing on April 15, 2017. The 2024 Notes will mature on October 15, 2024. The Company received approximately $640.0 million in net proceeds from the offering of the 2024 Notes, which was used, together with cash on hand, to purchase the outstanding 2020 Notes in a concurrent cash tender offer, to pay fees and expenses thereof, and to redeem any of the 2020 Notes that remained outstanding after the completion of the tender offer. For a discussion of the tender offer and related redemption, see “-Tender Offer and Redemption-Existing 2020 Notes.”

Tender Offer and Redemption-Existing 2020 Notes

On October 6, 2016, the Company commenced a cash tender offer to purchase any and all of its 2020 Notes, which tender offer expired on October 13, 2016 and settled on October 14, 2016. Holders of the 2020 Notes that were validly tendered and accepted at or prior to the expiration time of the tender offer, or who delivered the 2020 Notes pursuant to the guaranteed delivery procedures, received total cash consideration of $1,042 per $1,000 principal amount of notes, plus any accrued and

Table of Contents

unpaid interest up to, but not including, the settlement date. An aggregate of $403.5 million in principal amount of the 2020 Notes was validly tendered in the tender offer. The remaining 2020 Notes that were not tendered in the tender offer were redeemed by the Company. The redemption payment included approximately $196.5 million in aggregate principal amount at a redemption price of 103.875% of the principal amount of the redeemed 2020 Notes, plus accrued and unpaid interest thereon to the redemption date. Upon deposit of the redemption payment with the paying agent on October 14, 2016, the indenture governing the 2020 Notes was fully satisfied and discharged. The cash tender offer for the 2020 Notes and redemption of the remaining 2020 Notes were funded with the net proceeds from the offering of the 2024 Notes (discussed in more detail above) and cash on hand.

Derivatives

In October 2016, the Company entered into fixed price swaps for the period from January 2017 through June 2017, for 20,000 MMBtu of natural gas per day at a weighted average price of $3.19 per MMBtu. For the period from July 2017 through October 2017, the Company entered into fixed price swaps for 40,000 MMBtu of natural gas per day at a weighted average price of $3.15 per MMBtu. For the period from November 2017 through December 2017, the Company entered into fixed price swaps for 70,000 MMBtu of natural gas per day at a weighted average price of $3.25 per MMBtu. For the period from January 2018 through March 2018, the Company entered into fixed price swaps for 70,000 MMBtu of natural gas per day at a weighted average price of $3.19 per MMBtu. For the period from April 2018 through December 2018, the Company entered into fixed price swaps for 20,000 MMBtu of natural gas per day at a weighted average price of $2.97 per MMBtu. The Company's fixed price swap contracts are tied to the commodity prices on NYMEX. The Company will receive the fixed price amount stated in the contract and pay to its counterparty the current market price as listed on NYMEX for natural gas.

Mammoth Energy Initial Public Offering

On October 19, 2016, Mammoth Energy closed its IPO of 7,750,000 shares of its common stock at a public offering price of $15.00 per share, of which 7,500,000 shares were sold by Mammoth Energy and 250,000 shares were sold by certain selling stockholders, including 76,250 shares sold by the Company for which it received net proceeds of $1.1 million. Prior to the completion of the IPO, the Company was issued 9,150,000 shares of Mammoth Energy common stock in return for the contribution of its 30.5% interest in Mammoth. The underwriters have an option, exercisable within 30-days after the IPO, to purchase at the same price per share up to an additional 1,162,500 shares of Mammoth Energy common stock from the selling stockholders, including up to 354,563 shares of common stock from the Company. The Company intends to use the net proceeds for the sale of its Mammoth Energy shares in the IPO for general corporate purposes. Following the IPO, the Company owned an approximate 24.2% interest in Mammoth Energy.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section and audited consolidated financial statements and related notes included in our Annual Report on Form 10-K and with the unaudited consolidated financial statements and related notes thereto presented in this Quarterly Report on Form 10-Q.

Disclosure Regarding Forward-Looking Statements

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. All statements other than statements of historical facts included in this report that address activities, events or developments that we expect or anticipate will or may occur in the future, including such things as estimated future net revenues from oil and natural gas reserves and the present value thereof, future capital expenditures (including the amount and nature thereof), business strategy and measures to implement strategy, competitive strength, goals, expansion and growth of our business and operations, plans, references to future success, reference to intentions as to future matters and other such matters are forward-looking statements. These statements are based on certain assumptions and analysis made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate in the circumstances. However, whether actual results and developments will conform with our expectations and predictions is subject to a number of risks and uncertainties, general economic, market or business conditions; the opportunities (or lack thereof) that may be presented to and pursued by us; competitive actions by other oil and natural gas companies; our ability to identify, complete and integrate acquisitions of properties and businesses; changes in laws or regulations; adverse weather conditions and natural disasters such as hurricanes and other factors, including those listed in the "Risk Factors" section of our most recent Annual Report on Form 10-K, Quarterly Reports on Form 10-Q or any other filings we make with the SEC, many of which are beyond our control. Consequently, all of the forward-looking statements made in this report are qualified by these cautionary statements, and we cannot assure you that the actual results or developments anticipated by us will be realized or, even if realized, that they will have the expected consequences to or effects on us, our business or operations. We have no intention, and disclaim any obligation, to update or revise any forward-looking statements, whether as a result of new information, future results or otherwise.

Overview

We are an independent oil and natural gas exploration and production company focused on the exploration, exploitation, acquisition and production of natural gas, crude oil and natural gas liquids in the United States. Our corporate strategy is to internally identify prospects, acquire lands encompassing those prospects and evaluate those prospects using subsurface geology and geophysical data and exploratory drilling. Using this strategy, we have developed an oil and natural gas portfolio of proved reserves, as well as development and exploratory drilling opportunities on high potential conventional and unconventional oil and natural gas prospects. Our principal properties are located in the Utica Shale in Eastern Ohio and along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields. In addition, we have producing properties in the Niobrara Formation of Northwestern Colorado and the Bakken Formation. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, and an interest in an entity that operates in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

Strong results from our existing production base and efficiencies realized in our completion activities resulted in our achieving 2015 production above expectations. Based on these strong results and efficiencies, and taking into consideration the continued weakness in natural gas commodity pricing, we idled completion crews and suspended our hydraulic fracturing activities during the first quarter of 2016, and entered into an agreement with one of our service providers that adjusted the amount of service fees that would otherwise be payable during this period. We resumed these activities on April 1, 2016. As a result of these suspended activities, our average daily production during the second quarter of 2016 was slightly below our production in the first quarter of 2016 due to normal production declines from existing wells and the timing of our wells turned-to-sales in 2016. Our renewed completion activities were recognized in the third quarter of 2016, with our average net daily production increasing 10% from the second quarter 2016. In addition, we began experiencing higher than anticipated gathering line pressures in an isolated portion of our dry gas development area of the play in the first half of 2016 which is having a near-term effect on our production levels. We, along with our third-party midstream providers, have developed a long-term, multi-phase compression plan for the optimization of our gathering systems and have begun implementing this plan. We installed pad level compression on a select group of wells during the third quarter and achieved the expected improvements resulting from th

Table of Contents

e targeted pressure drop within the isolated area. In addition, we currently expect to have field level compression online around year-end 2016.

2016 Operational Highlights

- Production increased 13% to 67,541 net million cubic feet of natural gas equivalent, or MMcfe, for the three months ended September 30, 2016 from 59,530 MMcfe for the three months ended September 30, 2015. Our net daily production mix was comprised of approximately 86% of natural gas, 9% of natural gas liquids, or NGLs, and 5% of oil.
- During the three months ended September 30, 2016, we spud nine gross (8.8 net) wells in the Utica Shale, participated in an additional eight gross (1.7 net) wells that were drilled by other operators on our Utica Shale acreage and recompleted 24 gross and net wells on our Louisiana acreage. Of our nine new wells spud at September 30, 2016, six were in various stages of completion, and three were being drilled. In addition, we turned-to-sales 21 gross (15.8 net) operated wells and 13 gross (3.9 net) non-operated wells during the three months ended September 30, 2016.
- During the nine months ended September 30, 2016, we reduced our unit lease operating expense by 30% to $0.26 per Mcfe from $0.36 per Mcfe during the nine months ended September 30, 2015.
- During the nine months ended September 30, 2016, we reduced our unit midstream gathering and processing expense by 10% to $0.64 per Mcfe from $0.71 per Mcfe during the nine months ended September 30, 2015.

2016 Production and Drilling Activity

During the three months ended September 30, 2016, our total net production was 58,150,669 thousand cubic feet, or Mcf, of natural gas, 521,356 barrels of oil and 43,837,087 gallons of NGLs for a total of 67,541 MMcfe, as compared to 48,123,538 Mcf of natural gas, 732,133 barrels of oil and 49,093,606 gallons of NGLs, or 59,530 MMcfe, for the three months ended September 30, 2015. Our total net production averaged approximately 734.1 MMcfe per day during the three months ended September 30, 2016 as compared to 647.1 MMcfe per day during the same period in 2015. The 13% increase in production is largely the result of the continuing development of our Utica Shale acreage.

Utica Shale. As of October 28, 2016, we held leasehold interests in approximately 222,000 gross (211,000 net) acres in the Utica Shale. From January 1, 2016 through October 28, 2016, we spud 35 gross (31.7 net) wells, of which five were producing, 24 were in various stages of completion, four were being drilled and two were non-productive at October 28, 2016. In addition, 20 gross (3.1 net) wells were drilled by other operators on our Utica Shale acreage during the nine months ended September 30, 2016.

As of October 28, 2016, we had four rigs under contract on our Utica Shale acreage and have contracted a fifth and sixth rig to begin operations in November 2016 and December 2016, respectively. We currently intend to spud 42 to 46 gross (36 to 39 net) wells on our Utica Shale acreage in 2016.

Aggregate net production from our Utica Shale acreage during the three months ended September 30, 2016 was approximately 65,599 MMcfe, or an average of 713.0 MMcfe per day, 89% of which was from natural gas and 11% of which was from oil and NGLs.

WCBB. From January 1, 2016 through October 28, 2016, we recompleted 48 wells and spud no new wells. Aggregate net production from the WCBB field during the three months ended September 30, 2016 was approximately 1,451 MMcfe, or an average of 15.8 MMcfe per day, 100% of which was from oil.

East Hackberry Field. From January 1, 2016 through October 28, 2016, we recompleted 19 wells and spud no new wells. Aggregate net production from the East Hackberry field during the three months ended September 30, 2016 was approximately 350 MMcfe, or an average of 3.8 MMcfe per day, 99% of which was from oil and 1% of which was from natural gas.

West Hackberry Field. From January 1, 2016 through October 28, 2016, we did not spud any wells in our West Hackberry field. Aggregate net production from the West Hackberry field during the three months ended September 30, 2016 was

approximately 57 MMcfe, or an average of 614.7 Mcfe per day, 99% of which was from oil and 1% of which was from natural gas.

Niobrara Formation. As of September 30, 2016, we held leases for approximately 4,800 net acres in the Niobrara Formation in Northwestern Colorado. From January 1, 2016 through October 28, 2016, there were no wells spud on our Niobrara Formation acreage and aggregate net production was approximately 23 MMcfe, or an average of 249.1 Mcfe per day during the three months ended September 30, 2016, 100% of which was from oil.

Bakken. As of September 30, 2016, we held approximately 778 net acres in the Bakken Formation of Western North Dakota and Eastern Montana with interests in 18 wells and overriding royalty interests in certain existing and future wells. Aggregate net production from this acreage during the three months ended September 30, 2016 was approximately 60 MMcfe, or an average of 655.7 Mcfe per day, of which 85% was from oil, 12% was from natural gas and 3% was from NGLs.

2016 Updates Regarding Our Equity Investments

Mammoth Energy Initial Public Offering. On October 19, 2016, Mammoth Energy Services, Inc., or Mammoth Energy, closed its initial public offering, or the IPO, of 7,750,000 shares of its common stock at a public offering price of $15.00 per share, of which 7,500,000 shares were sold by Mammoth Energy and 250,000 shares were sold by certain selling stockholders, including 76,250 shares sold by us for which we received net proceeds of $1.1 million. Prior to the completion of the IPO, we were issued 9,150,000 shares of Mammoth Energy common stock in return for the contribution of our 30.5% interest in Mammoth. The underwriters have an option, exercisable within 30-days after the IPO, to purchase at the same price per share up to an additional 1,162,500 shares of Mammoth Energy common stock from the selling stockholders, including up to 354,563 shares of common stock from us. We intend to use the net proceeds for the sale of our Mammoth Energy shares in the IPO for general corporate purposes. Following the IPO, we owned an approximate 24.2% interest in Mammoth Energy.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The preparation of these consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management. We analyze our estimates including those related to oil and natural gas properties, revenue recognition, income taxes and commitments and contingencies, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements:

Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including non-productive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for the prior twelve months, adjusted for any contract provisions or financial derivatives, if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and natural gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and natural gas reserves. Oil and natural gas properties not subject to amortization consist of the cost of undeveloped leaseholds and totaled approximately $1.7 billion at September 30, 2016 and $1.8 billion at December 31, 2015. These costs are reviewed quarterly by management for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. Factors considered by management in its impairment assessment include our drilling results and those of other operators, the terms of oil and natural gas leases not held by production and available funds for exploration and development.

Ceiling Test. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling (as defined in the preceding paragraph). If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Ceiling test impairment can give us a significant loss for a particular period; however, future depletion expense would be reduced. A decline in oil and gas prices may result in an impairment of oil and gas properties. As a result of the decline in commodity prices, we recognized a ceiling test impairment of $601.8 million for the nine months ended September 30, 2016. If prices of oil, natural gas and natural gas liquids decline, we may be required to further write down the value of our oil and natural gas properties, which could negatively affect our results of operations.

Asset Retirement Obligations. We have obligations to remove equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells and associated production facilities.

We account for abandonment and restoration liabilities under FASB ASC 410 which requires us to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, we increase the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

The fair value of the liability associated with these retirement obligations is determined using significant assumptions, including current estimates of the plugging and abandonment or retirement, annual inflations of these costs, the productive life of the asset and our risk adjusted cost to settle such obligations discounted using our credit adjustment risk free interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to the carrying amount of the related long-lived asset, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of our oil and natural gas assets, the costs to ultimately retire these assets may vary significantly from previous estimates.

Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Netherland, Sewell & Associates, Inc. and to a lesser extent our personnel have prepared reserve reports of our reserve estimates at December 31, 2015 on a well-by-well basis for our properties.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Our reserve estimates and the projected cash flows derived from these reserve estimates have been prepared in accordance with the guidelines of the Securities and Exchange Commission, or SEC. The accuracy of our reserve estimates is a function of many factors including the following:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgments of the individuals preparing the estimates.

Our proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. Therefore, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

Table of Contents

Income Taxes. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable. Periodically, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management's opinion, it is more likely than not that some portion will not be realized. At September 30, 2016, a valuation allowance of $559.1 million had been established for the net deferred tax asset, with the exception of certain state NOL's and alternative minimum tax, or AMT, credits that we expect to utilize based on the positive evidence these assets may be realized.

Revenue Recognition. We derive almost all of our revenue from the sale of crude oil and natural gas produced from our oil and gas properties. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment on substantially all of these sales from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers that month and the price we will receive. Variances between our estimated revenue and actual payment received for all prior months are recorded at the end of the quarter after payment is received. Historically, our actual payments have not significantly deviated from our accruals.

Investments—Equity Method. Investments in entities greater than 20% and less than 50% and/or investments in which we have significant influence are accounted for under the equity method. Under the equity method, our share of investees’ earnings or loss is recognized in the statement of operations.

We review our investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, we recognize an impairment provision. For the nine months ended September 30, 2016, we recognized an impairment loss related to our investment in Grizzly of approximately $23.1 million, all of which was recorded in the first quarter of 2016.

Commitments and Contingencies. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. We are involved in certain litigation for which the outcome is uncertain. Changes in the certainty and the ability to reasonably estimate a loss amount, if any, may result in the recognition and subsequent payment of legal liabilities.

Derivative Instruments and Hedging Activities. We seek to reduce our exposure to unfavorable changes in oil, natural gas and natural gas liquids prices, which are subject to significant and often volatile fluctuation, by entering into over-the-counter fixed price swaps, basis swaps and various types of option contracts. We follow the provisions of FASB ASC 815, Derivatives and Hedging, as amended. It requires that all derivative instruments be recognized as assets or liabilities in the balance sheet, measured at fair value. We estimate the fair value of all derivative instruments using industry-standard models that considered various assumptions including current market and contractual prices for the underlying instruments, implied volatility, time value and nonperformance risk, as well as other relevant economic measures.

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. While we have historically designated derivative instruments as accounting hedges, effective January 1, 2015, we discontinued hedge accounting prospectively. Our current commodity derivative instruments are not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities.

See Item 3. "Quantitative and Qualitative Disclosures About Market Risk" for a summary of our derivative instruments in place as of September 30, 2016.

RESULTS OF OPERATIONS

Comparison of the Three Months Ended September 30, 2016 and 2015

We reported a net loss of $157.3 million for the three months ended September 30, 2016 as compared to net loss of $388.2 million for the three months ended September 30, 2015. This $230.9 million decrease in period-to-period net loss was due primarily to a $382.6 million decrease of impairment of oil and gas properties and a $28.0 million decrease in depreciation, depletion and amortization expense, partially offset by a $36.7 million decrease in oil and gas revenues and a $3.3 million increase in midstream gathering and processing expenses for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015.

Oil and Gas Revenues. For the three months ended September 30, 2016, we reported oil and natural gas revenues of $193.7 million as compared to oil and natural gas revenues of $230.4 million during the same period in 2015. This $36.7 million, or 16%, decrease in revenues was primarily attributable to the following:

- A $56.5 million decrease in oil and natural gas sales due to an unfavorable change in gains and losses from derivative instruments. Of the total change, $16.7 million was due to an unfavorable change in settlements related to our derivative positions. In addition, $39.8 million was due to unfavorable changes in the fair value of our open derivative positions in each period.

- A $22.5 million increase in gas sales without the impact of derivatives due to a 21% increase in gas sales volumes and a 1% increase in natural gas market prices.

- A $7.9 million decrease in oil and condensate sales without the impact of derivatives due to a 29% decrease in oil and condensate sales volumes, partially offset by a 3% increase in oil and condensate market prices.

- A $5.2 million increase in natural gas liquids sales without the impact of derivatives due to a 73% increase in natural gas liquids market prices, partially offset by an 11% decrease in natural gas liquids sales volumes.

The following table summarizes our oil and natural gas production and related pricing for the three months ended September 30, 2016, as compared to such data for the three months ended September 30, 2015:

Table of Contents

	Three months ended September 30,	
	2016	2015
	($ In thousands)	
Gas sales		
Gas production volumes (MMcf)	58,151	48,124
Gas sales without the impact of derivatives	$122,018	$99,531
Net gain on derivatives included in gas sales	33,167	79,684
Total Gas sales	$155,185	$179,215
Gas sales without the impact of derivatives ($/Mcf)	$2.10	$2.07
Impact from settled derivatives ($/Mcf)	$0.21	$0.55
Average Gas sales price, including settled derivatives ($/Mcf)	$2.31	$2.62
Oil and condensate sales		
Oil and condensate production volumes (MBbls)	521	732
Oil and condensate sales without the impact of derivatives	$21,799	$29,675
Net gain on derivatives included in oil and condensate sales	1,708	12,072
Total Oil and condensate sales	$23,507	$41,747
Oil and condensate sales without the impact of derivatives ($/Bbl)	$41.81	$40.53
Impact from settled derivatives ($/Bbl)	$1.62	$4.31
Average Oil and condensate sales price, including settled derivatives ($/Bbl)	$43.43	$44.84
Natural gas liquids sales		
Natural gas liquids production volumes (MGal)	43,837	49,094
Natural gas liquids sales without the impact of derivatives	$14,594	$9,431
Net gain on derivatives included in natural gas liquid sales	406	—
Total Natural gas liquids sales	$15,000	$9,431
Natural gas liquids sales without the impact of derivatives ($/Gal)	$0.33	$0.19
Impact from settled derivatives ($/Gal)	$—	$—
Average Natural gas liquids sales price, including settled derivatives ($/Gal)	$0.33	$0.19

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes decreased to $17.5 million for the three months ended September 30, 2016 from $17.6 million for the three months ended September 30, 2015. This decrease was mainly the result of a decrease in expenses related to contract labor, disposal costs and facility repairs and maintenance, partially offset by increases in ad valorem taxes, compressor expense, overhead and water hauling expenses.

Production Taxes. Production taxes decreased $0.1 million to $3.5 million for the three months ended September 30, 2016 from $3.6 million for the three months ended September 30, 2015. This decrease was related to changes in our product mix and production location as well as a decrease in realized prices.
Midstream Gathering and Processing Expenses. Midstream gathering and processing expenses increased $3.3 million to $45.5 million for the three months ended September 30, 2016 from $42.2 million for the same period in 2015. This

increase was primarily attributable to midstream expenses related to our increased production volumes in the Utica Shale resulting from our 2015 and 2016 drilling activities.

Table of Contents

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense decreased to $62.3 million for the three months ended September 30, 2016, and consisted of $61.6 million in depletion of oil and natural gas properties and $0.7 million in depreciation of other property and equipment, as compared to total DD&A expense of $90.3 million for the three months ended September 30, 2015. This decrease was due to a decrease in our full cost pool as a result of our 2015 and 2016 ceiling test impairments, partially offset by an decrease in our total proved reserves volume used to calculate our total DD&A expense and an increase in our production.

General and Administrative Expenses. Net general and administrative expenses decreased to $10.5 million for the three months ended September 30, 2016 from $11.0 million for the three months ended September 30, 2015. This $0.5 million decrease was due to a decrease in employee stock compensation expense, partially offset by increases in salaries and benefits, bank fees, legal fees, accounting fees and consulting fees.

Accretion Expense. Accretion expense remained relatively flat at $0.3 million and $0.2 million for the three months ended September 30, 2016 and 2015, respectively.

Interest Expense. Interest expense decreased to $12.8 million for the three months ended September 30, 2016 from $14.1 million for the three months ended September 30, 2015 due primarily to an increase in the amount of interest capitalized during the three months ended September 30, 2016 as compared to the same period in 2015. We capitalized approximately $4.7 million and $3.6 million in interest expense to undeveloped oil and natural gas properties during the three months ended September 30, 2016 and 2015, respectively. This increase in capitalized interest in the 2016 period was the result of changes to our development plan for our oil and natural gas properties.

Income Taxes. As of September 30, 2016, we had a net operating loss carryforward of approximately $138.0 million, in addition to numerous temporary differences, which gave rise to a net deferred tax asset. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management's opinion, it is more likely than not that some portion will not be realized. At September 30, 2016, a valuation allowance of $559.1 million had been provided against the net deferred tax asset, with the exception of certain state net operating losses and AMT credits that we expect to be able to utilize with net operating loss carrybacks and tax planning in the amount of $4.2 million. We recognized an income tax benefit of $3.4 million for the three months ended September 30, 2016.

Comparison of the Nine Months Ended September 30, 2016 and 2015

We reported a net loss of $739.3 million for the nine months ended September 30, 2016 as compared to a net loss of $394.0 million for the nine months ended September 30, 2015. This $345.3 million increase in period-to-period net loss was due primarily to a $196.3 million decrease in oil and gas revenues, a $213.2 million decrease in income tax benefit, a $22.0 million increase in midstream gathering and processing expenses, a $7.0 million increase in impairment of oil and gas properties and a $10.0 million increase in interest expense, partially offset by a $68.0 million decrease in depreciation, depletion and amortization expense for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015.

Oil and Gas Revenues. For the nine months ended September 30, 2016, we reported oil and natural gas revenues of $322.5 million as compared to oil and natural gas revenues of $518.8 million during the same period in 2015. This $196.3 million, or 38%, decrease in revenues was primarily attributable to the following:

- A $176.2 million decrease in oil and natural gas revenues due to an unfavorable change in gains and losses from derivative instruments. Of the total change, $242.9 million was due to an unfavorable change in the fair value of our open derivative positions in each period. This amount was offset by a favorable change of $66.7 million due to a favorable change in settlements related to our derivative positions.

- A $26.4 million increase in gas sales without the impact of derivatives due to a 53% increase in gas sales volumes largely offset by a 28% decrease in natural gas market prices.

- A $37.3 million decrease in oil and condensate sales without the impact of derivatives due to a 25% decrease in oil and condensate sales volumes and an 18% decrease in oil and condensate market prices.

- A $9.2 million decrease in natural gas liquid sales without the impact of derivatives due to an 18% decrease in natural gas liquids sales volumes and a 5% decrease in natural gas liquid market prices.

Table of Contents

The following table summarizes our oil and natural gas production and related pricing for the nine months ended September 30, 2016, as compared to such data for the nine months ended September 30, 2015:

	Nine months ended September 30,	
	2016	2015
	($ In thousands)	
Gas sales		
Gas production volumes (MMcf)	164,233	107,208
Gas sales without the impact of derivatives	$271,873	$245,519
Net (loss) gain on derivatives included in gas sales	(43,454)	118,137
Total Gas sales	$228,419	$363,656
Gas sales without the impact of derivatives ($/Mcf)	$1.66	$2.29
Impact from settled derivatives ($/Mcf)	$0.78	$0.64
Average Gas sales price, including settled derivatives ($/Mcf)	$2.44	$2.93
Oil and condensate sales		
Oil and condensate production volumes (MBbls)	1,675	2,225
Oil and condensate sales without the impact of derivatives	$60,799	$98,071
Net gain on derivatives included in oil and condensate sales	362	13,641
Total Oil and condensate sales	$61,161	$111,712
Oil and condensate sales without the impact of derivatives ($/Bbl)	$36.31	$44.08
Impact from settled derivatives ($/Bbl)	$6.42	$2.06
Average Oil and condensate sales price, including settled derivatives ($/Bbl)	$42.73	$46.14
Natural gas liquids sales		
Natural gas liquids production volumes (MGal)	117,217	142,093
Natural gas liquids sales without the impact of derivatives	$34,198	$43,396
Net loss on derivatives included in natural gas liquids sales	(1,284)	—
Total Natural gas liquids sales	$32,914	$43,396
Natural gas liquids sales without the impact of derivatives ($/Gal)	$0.29	$0.31
Impact from settled derivatives ($/Gal)	$—	$—
Average Natural gas liquids sales price, including settled derivatives ($/Gal)	$0.29	$0.31

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes decreased to $48.8 million for the nine months ended September 30, 2016 from $51.4 million for the nine months ended September 30, 2015. This decrease was mainly the result of a decrease in expenses related to contract labor, disposal costs and road, location and equipment repairs, partially offset by an increase in overhead, compressors, ad valorem taxes and water hauling expenses.

Production Taxes. Production taxes decreased $1.7 million to $9.5 million for the nine months ended September 30, 2016 from $11.2 million for the same period in 2015. This decrease was primarily related to changes in our product mix and production location as well as a decrease in realized prices.

Table of Contents

Midstream Gathering and Processing Expenses. Midstream gathering and processing expenses increased by $22.0 million to $122.5 million for the nine months ended September 30, 2016 from $100.5 million for the same period in 2015. This increase was primarily attributable to midstream expenses related to our increased production volumes in the Utica Shale resulting from our 2015 and 2016 drilling activities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense decreased to $183.4 million for the nine months ended September 30, 2016, and consisted of $181.4 million in depletion of oil and natural gas properties and $2.0 million in depreciation of other property and equipment, as compared to total DD&A expense of $251.4 million for the nine months ended September 30, 2015. This decrease was due to a decrease in our full cost pool as a result of our 2015 and 2016 ceiling test impairments, partially offset by a decrease in our total proved reserves volume used to calculate our total DD&A expense and an increase in our production.

General and Administrative Expenses. Net general and administrative expenses increased to $32.9 million for the nine months ended September 30, 2016 from $31.3 million for the nine months ended September 30, 2015. This $1.6 million increase was due to an increase in consulting fees, salaries and related employee benefits, bank fees, accounting fees, legal fees, computer support expenses and franchise taxes, partially offset by a decrease in employee stock compensation expense.

Accretion Expense. Accretion expense was $0.8 million and $0.6 million for the nine months ended September 30, 2016 and 2015, respectively.

Interest Expense. Interest expense increased to $44.9 million for the nine months ended September 30, 2016 from $34.9 million for the nine months ended September 30, 2015 due partially to the issuance of $350.0 million of 6.625% Senior Notes due 2023 on April 21, 2015. This increase is partially offset by total weighted debt outstanding under our revolving credit facility of $62.3 million for the nine months ended September 30, 2015 as compared to no debt outstanding under such facility for the nine months ended September 30, 2016. Additionally, we capitalized approximately $7.7 million and $12.0 million in interest expense to undeveloped oil and natural gas properties during the nine months ended September 30, 2016 and September 30, 2015, respectively. This decrease in capitalized interest in the 2016 period was the result of changes to our development plan for our oil and natural gas properties. Additionally, we capitalized approximately $1.2 million in interest expense related to our construction loan during the nine months ended September 30, 2016.

Income Taxes. As of September 30, 2016, we had a net operating loss carryforward of approximately $138.0 million, in addition to numerous temporary differences, which gave rise to a net deferred tax asset. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management's opinion, it is more likely than not that some portion will not be realized. At September 30, 2016, a valuation allowance of $559.1 million had been provided against the net deferred tax asset, with the exception of certain state net operating losses and AMT credits that we expect to be able to utilize with net operating loss carrybacks and tax planning in the amount of $4.2 million. We recognized an income tax benefit of $3.8 million for the nine months ended September 30, 2016.

Liquidity and Capital Resources

Overview.

Historically, our primary sources of funds have been cash flow from our producing oil and natural gas properties, borrowings under our credit facility and the issuances of equity and debt securities. Our ability to access any of these sources of funds can be significantly impacted by decreases in oil and natural gas prices or oil and natural gas production. During 2015, we received net proceeds of approximately $343.6 million from the sale of our 6.625% Senior Notes due 2023 issued in April 2015. In addition, we received an aggregate of $981.5 million in net proceeds from the sale of shares of our common stock in underwritten public offerings completed in April and June 2015.

On March 15, 2016, we issued 16,905,000 shares of our common stock in an underwritten public offering (which included 2,205,000 shares sold pursuant to an option to purchase additional shares of our common stock granted by the us to, and exercised in full by, the underwriters). The net proceeds from this equity offering were approximately $411.7 million, after deducting underwriting discounts and commissions and offering expenses. We intend to use the net proceeds from the offering primarily to fund a portion of our 2017 capital development plan and for general corporate purposes.

Net cash flow provided by operating activities was $245.3 million for the nine months ended September 30, 2016 as compared to net cash flow provided by operating activities of $235.1 million for the same period in 2015. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 10% increase in net revenues after giving effect to settled derivative instruments, partially offset by an increase in our operating expenses.

Net cash used in investing activities for the nine months ended September 30, 2016 was $420.3 million as compared to $1.4 billion for the same period in 2015. During the nine months ended September 30, 2016, we spent $441.1 million in additions to oil and natural gas properties, of which $220.7 million was spent on our 2016 drilling, completion and recompletion activities, $96.3 million was spent on expenses attributable to wells spud, completed and recompleted during 2015, $4.2 million was spent on facility enhancements, $53.4 million was spent on lease related costs, primarily the acquisition of leases in the Utica Shale, with the remainder attributable mainly to future location development and capitalized general and administrative expenses. In addition, $14.5 million was invested in Grizzly and $4.0 million was invested in Strike Force during the nine months ended September 30, 2016. We also received approximately $41.5 million from the sale of oil and gas properties, primarily the sale of non-producing leasehold acreage in the non-core area of our Utica acreage. We did not make any investments in our other equity investments during the nine months ended September 30, 2016.

Net cash provided by financing activities for the nine months ended September 30, 2016 was $426.3 million as compared to $1.2 billion for the same period in 2015. The 2016 amount provided by financing activities is primarily attributable to the net proceeds of approximately $411.7 million from our 2016 equity offering.

Credit Facility.

We have entered into a senior secured revolving credit facility, as amended, with The Bank of Nova Scotia, as the lead arranger and administrative agent and certain lenders from time to time party thereto. The credit agreement provides for a maximum facility amount of $1.5 billion and matures on June 6, 2018. On February 19, 2016, we further amended our credit facility to, among other things, (a) increase the basket for unsecured debt issuances to $1.35 billion from $1.2 billion (of which $950 million was then outstanding), (b) reaffirm our borrowing base of $700.0 million, and (c) increase the percentage of projected oil and gas production that may be hedged by us during 2016. As of September 30, 2016, we had no balance outstanding under our revolving credit facility and total funds available for borrowing, after giving effect to an aggregate of $207.0 million of outstanding letters of credit, were $493.0 million. This facility is secured by substantially all of our assets. Our wholly-owned subsidiaries guarantee our obligations under our revolving credit facility.

Advances under our revolving credit facility may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 0.50% to 1.50%, plus (2) the highest of: (a) the federal funds rate plus 0.50%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its “prime rate,” and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 1.50% to 2.50%, plus (2) the London interbank offered rate that appears on pages LIBOR01 or LIBOR02 of the Reuters screen that displays such rate for deposits in U.S. dollars, or, if such rate is not available, the rate as administered by ICE Benchmark Administration (or any other person that takes over administration of such rate) per annum equal to the offered rate on such other page or other service that displays an average London interbank offered rate as administered by ICE Benchmark Administration (or any other person that takes over the administration of such rate) for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the “London Interbank Offered Rate” for deposits in U.S. dollars.

Our revolving credit facility contains customary negative covenants including, but not limited to, restrictions on our and our subsidiaries' ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in our revolving credit facility. Our revolving credit facility also contains certain affirmative covenants, including, but not limited to the following financial covenants: (1) the ratio of net funded debt to EBITDAX (net income, excluding (i) any non-cash revenue or expense associated with swap contracts resulting from ASC 815 and (ii) any cash or non-cash revenue or expense attributable to minority investment plus without duplication and, in the case of expenses, to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) exploration costs deducted in determining net income under successful efforts accounting, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offerings (provided that expenses related to any

Table of Contents

unsuccessful dispositions will be limited to $3.0 million in the aggregate) for a twelve-month period may not be greater than 4.00 to 1.00; and (2) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. We were in compliance with these financial covenants at September 30, 2016.

Senior Notes due 2020.

In October 2012, December 2012 and August 2014, we issued an aggregate of $600.0 million in principal amount of our senior notes due 2020 which we refer to as the 2020 Notes. Interest on the 2020 Notes accrued at a rate of 7.75% per annum on the outstanding principal amount payable semi-annually on May 1 and November 1 of each year. The 2020 Notes were scheduled to mature on November 1, 2020. On October 6, 2016, we commenced a cash tender offer to purchase any and all of the 2020 Notes, which tender offer expired on October 13, 2016 and settled on October 14, 2016. Holders of the 2020 Notes that were validly tendered and accepted at or prior to the expiration time of the tender offer, or who delivered the 2020 Notes pursuant to the guaranteed delivery procedures, received total cash consideration of $1,042.00 per $1,000 principal amount of notes, plus any accrued and unpaid interest up to, but not including, the settlement date. An aggregate of $403.5 principal amount of the 2020 Notes was validly tendered in the tender offer. The remaining 2020 Notes that were not tendered in the tender offer were redeemed by us. The redemption payment included approximately $196.5 million in aggregate principal amount at a redemption price of 103.875% of the principal amount of the redeemed 2020 Notes, plus accrued and unpaid interest thereon to the redemption date. Upon deposit of the redemption payment with the paying agent on October 14, 2016, the indenture governing the 2020 Notes was fully satisfied and discharged. The cash tender offer for the 2020 Notes and redemption of the remaining 2020 Notes were funded with the net proceeds from the offering of the 2024 Notes (discussed in more detail below) and cash on hand.

Outstanding Senior Notes.

Senior Notes due 2023. In April 2015, we issued an aggregate of $350.0 million in principal amount of our senior notes due 2023. Interest on these senior notes, which we refer to as the 2023 Notes, accrues at a rate of 6.625% per annum on the outstanding principal amount thereof on May 1 and November 1 of each year. The 2023 Notes mature on May 1, 2023. The 2023 Notes are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior in right of payment to any of our future subordinated indebtedness.

Senior Notes due 2024. On October 14, 2016, we issued $650.0 million in aggregate principal amount of 6.000% Senior Notes due 2024, which we refer to as the 2024 Notes. Interest on the 2024 Notes accrues at a rate of 6.000% per annum on the outstanding principal amount thereof from October 14, 2016, payable semi-annually on April 15 and October 15 of each year, commencing on April 15, 2017. The 2024 Notes will mature on October 15, 2024. The 2024 Notes are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness, including the 2023 Notes, and senior in right of payment to any of our future subordinated indebtedness. We may redeem some or all of the 2024 Notes at any time on or after October 15, 2019, at the redemption prices listed in the indenture relating to the 2024 Notes. Prior to October 15, 2019, we may redeem all or a portion of the 2024 Notes at a price equal to 100% of the principal amount of the Notes plus a “make-whole” premium and accrued and unpaid interest to the redemption date. In addition, any time prior to October 15, 2019, we may redeem the 2024 Notes in an aggregate principal amount not to exceed 35% of the aggregate principal amount of the 2024 Notes issued prior to such date at a redemption price of 106%, plus accrued and unpaid interest to the redemption date, with an amount equal to the net cash proceeds from certain equity offerings.

If we experience a change of control (as defined in the indenture relating to the 2024 Notes), we will be required to make an offer to repurchase the 2024 Notes at a price equal to 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase. If we sell certain assets and fail to use the proceeds in a manner specified in the indenture, we will be required to use the remaining proceeds to make an offer to repurchase the 2024 Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase.

In connection with the issuance of the 2024 Notes, we and our subsidiary guarantors entered into a registration rights agreement pursuant to which we agreed to file a registration statement with respect to an offer to exchange the Notes for a new issue of substantially identical debt securities registered under the Securities Act of 1933, as amended. We may be required to file a shelf registration statement to cover resales of the 2024 Notes under certain circumstances. If we fail to satisfy these obligations under the registration rights agreement, we agreed to pay additional interest to the holders of the 2024 Notes as specified in the registration rights agreement.

Table of Contents

All of our existing restricted subsidiaries that guarantee our secured revolving credit facility or certain other debt (other than Grizzly Holdings, Inc.) guarantee the 2023 Notes and the 2024 Notes. The guarantees rank equally in the right of payment with all of the senior indebtedness of the subsidiary guarantors and senior in the right of payment to any future subordinated indebtedness of the subsidiary guarantors. The 2023 Notes and the 2024 Notes and the guarantees are effectively subordinated to all of our and the subsidiary guarantors' secured indebtedness (including all borrowings and other obligations under our credit agreement) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated to all indebtedness and other liabilities of any of our subsidiaries that do not guarantee the 2023 Notes and the 2024 Notes.

The senior note indentures relating to the 2023 Notes and the 2024 Notes contain certain covenants that, subject to certain exceptions and qualifications, among other things, limit our ability and the ability of our restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make distributions on capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting our restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of our assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and gas business and designate certain of our subsidiaries as unrestricted subsidiaries. For additional information regarding the 2023 Notes and the 2024 Notes, see Note 6, Note 14 and Note 16 to our consolidated financial statements included elsewhere in this report.

Construction Loan.

In June 2015, we entered into a construction loan agreement, or the construction loan, with InterBank for the construction of our new corporate headquarters in Oklahoma City. The construction loan allows for maximum principal borrowings of $24.5 million and requires us to fund 30% of the estimated cost of the construction before any funds can be drawn, which occurred in January 2016. Interest accrues daily on the outstanding principal balance at a fixed rate of 4.5% per annum and is payable on the last day of the month through May 31, 2017. Monthly interest and principal payments are due beginning June 30, 2017, with the final payment due June 4, 2025. As of September 30, 2016, $16.5 million of borrowings were outstanding under the construction loan.

Capital Expenditures.

Our recent capital commitments have been primarily for the execution of our drilling programs, for acquisitions primarily in the Utica Shale, and for investments in entities that may provide services to facilitate the development of our acreage. Our strategy is to continue to (1) increase cash flow generated from our operations by undertaking new drilling, workover, sidetrack and recompletion projects to exploit our existing properties, subject to economic and industry conditions, (2) pursue acquisition and disposition opportunities and (3) pursue business integration opportunities.

Of our net reserves at December 31, 2015, 55.0% were categorized as proved undeveloped. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved developed reserves, or both. To realize reserves and increase production, we must continue our exploratory drilling, undertake other replacement activities or use third parties to accomplish those activities.

From January 1, 2016 through October 28, 2016, we spud 35 gross (31.7 net) wells in the Utica Shale. We currently expect our 2016 capital expenditures to be $299.0 million to $347.0 million to drill 42 to 46 gross (36 to 39 net) horizontal wells and commence sales from 50 to 56 gross (37 to 41 net) wells on our Utica Shale acreage. As of October 28, 2016, we had four operated horizontal rigs drilling in the play. We also anticipate an additional 20 to 22 gross (three to four net) horizontal wells will be drilled, and sales commenced from 25 to 27 gross (six to seven net) horizontal wells, on our Utica Shale acreage by other operators for estimated 2016 expenditures to us of $90.0 million to $100.0 million. In addition, we currently expect to spend $40.0 million to $50.0 million in 2016 for acreage expenses, primarily lease extensions, in the Utica Shale.

From January 1, 2016 through October 28, 2016, we recompleted 48 existing wells and spud no new wells at our WCBB field. In our Hackberry fields, from January 1, 2016 through October 28, 2016, we recompleted 19 existing wells and spud no new wells. We currently expect our 2016 capital expenditures to be $26.0 million to $28.0 million for maintenance capital expenditures and recompletions in Southern Louisiana.

From January 1, 2016 through October 28, 2016, no new wells were spud on our Niobrara Formation acreage. We do not currently anticipate any capital expenditures in the Niobrara Formation in 2016.

As of September 30, 2016, our net investment in Grizzly was approximately $48.6 million. During the nine months ended September 30, 2016, we paid cash calls of $14.5 million to Grizzly. Effective October 5, 2012, Grizzly entered into a $125.0

million revolving credit facility, of which all outstanding balance was paid as of September 30, 2016. We do not currently anticipate any additional material capital expenditures in 2016 related to Grizzly's activities.

In connection with the formation of Strike Force, we contributed certain assets valued at $22.5 million, including an approximately 11 mile-long, 12-inch diameter gathering line. During the nine months ended September 30, 2016, we paid cash calls of $4.0 million to Strike Force. We currently expect to make $20.0 million to $25.0 million in cash contributions to Strike Force in 2016.

We had no capital expenditures during the nine months ended September 30, 2016 related to our interests in Thailand. We do not currently anticipate any capital expenditures in Thailand in 2016.

In an effort to facilitate the development of our Utica Shale and other domestic acreage, we have invested in entities that can provide services that are required to support our operations, including pressure pumping and proppant. See Note 3 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments. In the nine months ended September 30, 2016, we did not make any investments in these entities, and we do not currently anticipate any capital expenditures related to these entities in 2016.

During 2015 and 2016, we continued to focus on operational efficiencies in an effort to reduce our overall well costs and deliver better results in a more economical manner, particularly in light of the continued downturn in commodity prices. We have successfully leveraged the lower commodity price environment to gain access to higher-quality equipment and superior services for reduced costs, which has contributed to increased productivity. We have also renegotiated the contracts for our horizontal drilling rigs and locked in approximately 70% of our drilling and completion costs through the remainder of 2016 and 2017. This has allowed us to secure a base level of activity for 2017, hedge against increases in service costs and ensure access to quality equipment and experienced crews, all of which we expect to contribute to further efficiency gains.

With regard to our leasehold position, we continue to upgrade our acreage within our portfolio and focus our efforts on consolidating our premium, core position in the wet gas and dry gas windows of the Utica Shale. During the third quarter of 2016, we sold a non-core exploratory acreage position in the Utica Shale in West Virginia and have already started to re-invest the net proceeds from that sale just across the border in the dry gas window of the Utica Shale in Ohio. We believe a significant organic leasing opportunity is unfolding in this area, where infrastructure build out exists or is underway and where we experience favorable economic returns.

As a result of the decline in commodity prices, our initial 2016 development plan contemplated running three rigs beginning in January 2016 and reducing activity levels throughout the year for an average of 2.5 rigs on our operated Utica Shale acreage during 2016, as compared to an average of 3.7 rigs in 2015. However, in response to the recent strengthening of natural gas prices, we contracted a fourth rig that began operations in September 2016 and currently plan to add two additional rigs, one in November 2016 and the other in December 2016. Our total capital expenditures for 2016 are currently estimated to be in the range of $475.0 million to $550.0 million, including $415.0 million to $475.0 million for drilling and completion expenditures, of which $369.2 million was spent as of September 30, 2016, $40.0 million to $50.0 million for acreage expenses, primarily lease extensions, in the Utica Shale, of which $9.8 million ($51.3 million net of $41.5 million of proceeds from our sale of non-producing, non-core exploratory leasehold acreage) was spent as of September 30, 2016, and $20.0 million to $25.0 million to fund our investment in Strike Force. Approximately 95% of our 2016 estimated capital expenditures are currently expected to be spent in the Utica Shale. The estimated 2016 range of capital expenditures for drilling and completion is down from the $851.8 million spent in 2015, primarily due to the low commodity price environment and a desire to maintain a favorable liquidity position.

We continually monitor market conditions and are prepared to adjust our drilling program if commodity prices dictate. Currently, we believe that our cash flow from operations, cash on hand and borrowings under our loan agreements will be sufficient to meet our normal recurring operating needs and capital requirements for the next twelve months. We believe that our strong liquidity position, hedge portfolio and conservative balance sheet position us well to react quickly to changing commodity prices and accelerate our activity within the Utica Basin to a six or possibly eight rig program in 2017, or to scale back our activity, as the market conditions warrant. Notwithstanding the foregoing, in the event commodity prices decline further, our capital or other costs increase, our equity investments require additional contributions and/or we pursue additional equity method investments or acquisitions, we may be required to obtain additional funds which we would seek to do through traditional borrowings, offerings of debt or equity securities or other means, including the sale of assets. We regularly evaluate new acquisition opportunities. Needed capital may not be available to us on acceptable terms or at all. Further, if we are unable to obtain funds when needed or on acceptable terms, we may be required to delay or curtail implementation of our business plan or not be able to complete acquisitions that may be favorable to us. If the low commodity price environment continues or worsens, our revenues, cash flows, results of operations, liquidity and reserves may be materially and adversely affected.

Commodity Price Risk

The volatility of the energy markets makes it extremely difficult to predict future oil and natural gas price movements with any certainty. During the past six years, the posted price for West Texas intermediate light sweet crude oil, which we refer to as West Texas Intermediate or WTI, has ranged from a low of $26.05 per barrel, or Bbl, in February 2016 to a high of $113.39 per Bbl in April 2011. The Henry Hub spot market price of natural gas has ranged from a low of $1.61 per MMBtu in March 2016 to a high of $7.51 per MMBtu in January 2010. On October 28, 2016, the WTI posted price for crude oil was $48.70 per Bbl and the Henry Hub spot market price of natural gas was $3.11 per MMBtu. If the prices of oil and natural gas continue at current levels or decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected. In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to further write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Reductions in our reserves could also negatively impact the borrowing base under our revolving credit facility, which could further limit our liquidity and ability to conduct additional exploration and development activities.

See Item 3. Quantitative and Qualitative Disclosures about Market Risk for information regarding our open fixed price swaps at September 30, 2016.

Commitments

In connection with our acquisition in 1997 of the remaining 50% interest in the WCBB properties, we assumed the seller's (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until our abandonment obligations to Chevron have been fulfilled. Beginning in 2009, we could access the trust for use in plugging and abandonment charges associated with the property. As of September 30, 2016, the plugging and abandonment trust totaled approximately $3.1 million. At September 30, 2016, we have plugged 483 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

Contractual and Commercial Obligations

We have various contractual obligations in the normal course of our operations and financing activities. There have been no material changes to our contractual obligations from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2015.

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of September 30, 2016.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, No. 2014-09, Revenue from Contracts with Customers, which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. The core principle of the new standard is for the recognition of revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which the company expects to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. The ASU is effective for annual periods beginning after December 15, 2016, and interim periods within those years, using either a full or a modified retrospective application approach. In July 2015, the FASB decided to defer the effective date by one year (until 2018). We are in the process of evaluating the impact on our consolidated financial statements.

Table of Contents

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements - Going Concern (Subtopic 205-40). The new guidance addresses management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and in certain circumstances to provide related footnote disclosures. The standard is effective for periods after December 15, 2016, with early adoption permitted. We do not believe that the adoption of this guidance will have a material impact on our consolidated financial statements.
In April 2015, the FASB issued ASU No. 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. This ASU provides additional guidance to reporting entities in evaluating whether certain legal entities, such as limited partnerships, limited liability corporation and securitization structure, should be consolidated. The ASU is considered to be an improvement on current accounting requirements as it reduces the number of existing consolidation models. The ASU is for periods after December 15, 2015 and is required to be adopted using a retrospective or modified retrospective approach, with early adoption permitted. We adopted this ASU on January 1, 2016. As a result, certain of our equity investments were determined to be variable interest entites; however, we were not required to consolidate these investments.

In April 2015, the FASB issued ASU No. 2015-03, Simplifying the Presentation of Debt Issuance Costs. To simplify the presentation of debt issuance costs, ASU 2015-03 requires that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts. This guidance is effective for periods after December 15, 2015. We adopted this guidance effective December 31, 2015, and have reclassified $16.0 million and $17.9 million of debt issuance costs to offset long-term debt at September 30, 2016 and December 31, 2015, respectively, as shown in Note 6 to our consolidated financial statements included elsewhere in this quarterly report.

In September 2015, the FASB issued ASU No. 2015-16, Simplifying the Accounting for Measurement-Period Adjustments. The guidance eliminates the requirement to retrospectively adjust the financial statements for measurement-period adjustments that occur in periods after a business combination is consummated. Measurement period adjustments are calculated as if they were known at the acquisition date, but are recognized in the reporting period in which they are determined. Additional disclosures are required about the impact on current-period income statement line items of adjustments that would have been recognized in prior periods if the prior-period information had been revised. The guidance is effective for periods after December 15, 2015. We adopted this guidance in the first quarter of 2016 and there was no material impact to our consolidated financial statements.
In November 2015, the FASB issued ASU No. 2015-17, Balance Sheet Classification of Deferred Taxes (Topic 705). Current guidance requires an entity to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified statement of financial position. Deferred tax liabilities and assets are classified as current or noncurrent based on the classification of the related asset or liability for financial reporting. Deferred tax liabilities and assets that are not related to an asset or liability for financial reporting are classified according to the expected reversal date of the temporary difference. To simplify the presentation of deferred income taxes, the amendments in this update require that deferred income tax liabilities and assets be classified as noncurrent in a classified statement of financial position. This guidance is effective for periods after December 15, 2016, with early adoption permitted. We are in the process of evaluating the impact of this guidance on our consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, Leases. The guidance requires the lessee to recognize most leases on the balance sheet thereby resulting in the recognition of lease assets and liability for those leases currently classified as operating leases. The accounting for lessors is largely unchanged. The guidance is effective for periods after December 15, 2018, with early adoption permitted. We are in the process of evaluating the impact of this guidance on our consolidated financial statements.

In March 2016, the FASB issued ASU No. 2016-05, Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships. The guidance was issued to clarify that change in the counterparty to a derivative instrument that had been designated as the hedging instrument under Topic 815, does not require dedesignation of that hedging relationship provided that all other hedge accounting criteria continue to be met. This guidance is effective for periods after December 15, 2017, with early adoption permitted. We are in the process of evaluating the impact on our consolidated financial statements. We do not believe that the adoption of this guidance will have a material impact on our consolidated financial statements because all current derivative instruments are not designated for hedge accounting.

In March 2016, the FASB issued ASU No. 2016-07, Equity Method and Joint Ventures. This guidance simplified current requirements by eliminating the need to retrospectively apply the equity method of accounting upon obtaining significant influence over an investment that it previously accounted for under the cost basis or at fair value. This guidance is effective for periods after December 15, 2016, with early adoption permitted. We are in the process of evaluating the impact on our

consolidated financial statements. We do not believe that the adoption of this guidance will have a material impact on our consolidated financial statements because all current investments are accounted under the equity method investment.
In March 2016, the FSB issued ASU No. 2016-09, Improvements to Employee Share-Based Payment Accounting. This guidance was intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. This guidance is effective for periods after December 15, 2016, with early adoption permitted. We are in the process of evaluating the impact of this guidance on our consolidated financial statements.

In May 2016, the FASB issued ASU No. 2016-11, Revenue Recognition and Derivatives and Hedging: Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant to Staff Announcements at the March 3, 2016 EITF Meeting. This guidance rescinds SEC Staff Observer comments that are codified in Topic 606, Revenue Recognition, and Topic 932, Extractive Activities--Oil and Gas. This amendment is effective upon adoption of Topic 606. We are in the process of evaluating the impact of this guidance on our consolidated financial statements.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments. This guidance provides guidance of eight specific cash flow issues. This amendment is effective for periods after December 15, 2017, with early adoption permitted. We are in the process of evaluating the impact of this guidance on our consolidated financial statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors, including: worldwide and domestic supplies of oil and natural gas; the level of prices, and expectations about future prices, of oil and natural gas; the cost of exploring for, developing, producing and delivering oil and natural gas; the expected rates of declining current production; weather conditions, including hurricanes, that can affect oil and natural gas operations over a wide area; the level of consumer demand; the price and availability of alternative fuels; technical advances affecting energy consumption; risks associated with operating drilling rigs; the availability of pipeline capacity; the price and level of foreign imports; domestic and foreign governmental regulations and taxes; the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls; political instability or armed conflict in oil and natural gas producing regions; and the overall economic environment.
These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. During the past six years, the posted price for WTI, has ranged from a low of \$26.05 per barrel, or Bbl, in February 2016 to a high of \$113.39 per Bbl in April 2011. The Henry Hub spot market price of natural gas has ranged from a low of \$1.61 per MMBtu in March 2016 to a high of \$7.51 per MMBtu in January 2010. On October 28, 2016, the WTI posted price for crude oil was \$48.70 per Bbl and the Henry Hub spot market price of natural gas was \$3.11 per MMBtu. If the prices of oil and natural gas continue at current levels or decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected. In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to further write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Reductions in our reserves could also negatively impact the borrowing base under our revolving credit facility, which could further limit our liquidity and ability to conduct additional exploration and development activities.

To mitigate the effects of commodity price fluctuations on our oil and natural gas production, we had the following open fixed price swap positions at September 30, 2016:

	Location	Daily Volume (Bbls/day)	Weighted Average Price
October 2016 - June 2017	ARGUS LLS	2,000	$ 51.10

Table of Contents

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
October 2016	NYMEX Henry Hub	570,000	$ 3.05
November 2016 - December 2016	NYMEX Henry Hub	525,000	$ 3.18
January 2017 - February 2017	NYMEX Henry Hub	442,500	$ 3.14
March 2017	NYMEX Henry Hub	422,500	$ 3.13
April 2017 - June 2017	NYMEX Henry Hub	367,500	$ 3.15
July 2017 - October 2017	NYMEX Henry Hub	305,000	$ 2.99
November 2017 - December 2017	NYMEX Henry Hub	435,000	$ 3.06
January 2018 - March 2018	NYMEX Henry Hub	290,000	$ 3.10
April 2018 - December 2018	NYMEX Henry Hub	160,000	$ 3.01
January 2019 - March 2019	NYMEX Henry Hub	20,000	$ 3.37

	Location	Daily Volume (Bbls/day)	Weighted Average Price
October 2016 - December 2016	Mont Belvieu	1,500	$ 19.95

We sold call options and used the associated premiums to enhance the fixed price for a portion of the fixed price natural gas swaps listed above. Each short call option has an established ceiling price. When the referenced settlement price is above the price ceiling established by these short call options, we pay our counterparty an amount equal to the difference between the referenced settlement price and the price ceiling multiplied by the hedged contract volume.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
January 2017 - March 2017	NYMEX Henry Hub	105,000	$ 3.27
April 2017 - December 2017	NYMEX Henry Hub	125,000	$ 3.21
January 2018 - March 2018	NYMEX Henry Hub	20,000	$ 2.91

For a portion of the combined natural gas derivative instruments containing fixed price swaps and sold call options, the counterparty has an option to extend the original terms an additional twelve months for the period January 2017 through December 2017. The option to extend the terms expires in December 2016. If executed, we would have additional fixed price swaps for 30,000 MMBtu per day at a weighted average price of $3.33 per MMBtu and additional short call options for 30,000 MMBtu per day at a weighted average ceiling price of $3.33 per MMBtu.

In addition, we have entered into natural gas basis swap positions, which settle on the pricing index to basis differential of MichCon or Tetco M2 to the NYMEX Henry Hub natural gas price. As of September 30, 2016, we had the following natural gas basis swap positions for MichCon and Tetco M2, respectively.

	Location	Daily Volume (MMBtu/day)	Hedged Differential
October 2016 - December 2016	MichCon	40,000	$ 0.02
November 2016 - March 2017	Tetco M2	50,000	$ (0.59)

Under our 2016 contracts, we have hedged approximately 75% to 79% of our estimated 2016 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. At September 30, 2016, we had a net asset derivative position of $2.5 million as compared to a net asset derivative position of $161.7 million as of September 30, 2015, related to our fixed price swaps. Utilizing actual derivative contractual volumes, a 10% increase in underlying commodity prices would have reduced the fair value of these instruments by approximately $79.8 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $79.8 million. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Our revolving amended and restated credit agreement is structured under floating rate terms, as advances under this facility may be in the form of either base rate loans or eurodollar loans. As such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. or, if the eurodollar rates are elected, the eurodollar rates. As of September 30, 2016, we had no variable interest rate borrowings outstanding; therefore, an increase in interest rates would not have impacted our interest expense. Our interest rate on borrowings under our revolving credit facility was 2.18% on April 20, 2015, the last day on which borrowings were outstanding under such facility. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $3.0 million based on the $300.0 million outstanding in the aggregate under our revolving credit facility as of such date. As of September 30, 2016, we did not have any interest rate swaps to hedge our interest risks.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures. Under the direction of our Chief Executive Officer and President and our Chief Accounting Officer, we have established disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and President and our Chief Accounting Officer, as appropriate to allow timely decisions regarding required disclosures.

As of September 30, 2016, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and President and our Chief Accounting Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and President and our Chief Accounting Officer have concluded that, as of September 30, 2016, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

Table of Contents

PART II

ITEM 1. LEGAL PROCEEDINGS

In two separate complaints, one filed by the State of Louisiana and the Parish of Cameron in the 38th Judicial District Court for the Parish of Cameron on February 9, 2016 and the other filed by the State of Louisiana and the District Attorney for the 15th Judicial District of the State of Louisiana in the 15th Judicial District Court for the Parish of Vermillion on July 29, 2016, we were named as a defendant, among 26 oil and gas companies, in the Cameron Parish complaint and among more than 40 oil and gas companies in the Vermillion Parish complaint, or the Complaints. The Complaints were filed under the State and Local Coastal Resources Management Act of 1978, as amended, and the rules, regulations, orders and ordinances adopted thereunder, which we referred to collectively as the CZM Laws, and allege that certain of the defendants' oil and gas exploration, production and transportation operations associated with the development of the East Hackberry and West Hackberry oil and gas fields, in the case of the Cameron Parish complaint, and the Tigre Lagoon oil and gas field, in the case of the Vermillion Parish complaint, were conducted in violation of the CZM Laws. The Complaints allege that such activities caused substantial damage to land and waterbodies located in the coastal zone of the relevant Parish, including due to defendants' design, construction and use of waste pits and the alleged failure to properly close the waste pits and to clear, re-vegetate, detoxify and return the property affected to its original condition, as well as the defendants' alleged discharge of waste into the coastal zone. The Complaints also allege that the defendants' oil and gas activities have resulted in the dredging of numerous canals, which had a direct and significant impact on the state coastal waters within the relevant Parish and that the defendants, among other things, failed to design, construct and maintain these canals using the best practical techniques to prevent bank slumping, erosion and saltwater intrusion and to minimize the potential for inland movement of storm-generated surges, which activities allegedly have resulted in the erosion of marshes and the degradation of terrestrial and aquatic life therein. The Complaints also allege that the defendants failed to re-vegetate, refill, clean, detoxify and otherwise restore these canals to their original condition. In these two petitions, the plaintiffs seek damages and other appropriate relief under the CZM Laws, including the payment of costs necessary to clear, re-vegetate, detoxify and otherwise restore the affected coastal zone of the relevant Parish to its original condition, actual restoration of such coastal zone to its original condition, and the payment of reasonable attorney fees and legal expenses and pre-judgment and post judgment interest.

We were served with the Cameron complaint in early May 2016 and with the Vermillion Complaint in early September 2016. The Louisiana Attorney General and the Louisiana Department of Natural Resources intervened in both the Cameron Parish suit and the Vermillion Parish suit. Shortly after the Complaints were filed, certain defendants removed the cases to the lawsuit to the United States District Court for the Western District of Louisiana. In both cases, the plaintiffs have filed a motion to remand, but both Courts have stayed further proceedings on the motions to remand pending a ruling from the United States Court of Appeals, Fifth Circuit on similar jurisdictional issues in another matter. The plaintiffs have granted all defendants an extension of time to file responsive pleadings to the Complaints until the District Courts rule on the motions to remand. We have not had the opportunity to evaluate the applicability of the allegations made in such complaints to our operations. Due to the early stages of these matters, management cannot determine the amount of loss, if any, that may result.

In addition, due to the nature of our business, we are, from time to time, involved in routine litigation or subject to disputes or claims related to our business activities, including workers' compensation claims and employment related disputes. In the opinion of our management, none of the pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

ITEM 1A. RISK FACTORS

See risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2015.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

(a) None.

(b) Not Applicable.

(c) We do not have a share repurchase program, and during the nine months ended September 30, 2016, we did not purchase any shares of our common stock.

Table of Contents

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

As previously disclosed, J. Ross Kirtley's employment as our Chief Operating Officer terminated on August 5, 2016. In connection with Mr. Kirtley's termination, we have entered into a separation and release agreement with Mr. Kirtley, dated as of November 2, 2016, which we refer to as the Separation Agreement, pursuant to which we agreed to provide Mr. Kirtley with (i) the cash compensation specified in his employment agreement, (ii) health care benefits for Mr. Kirtley and his eligible dependents for up to eighteen (18) months following the termination date, (iii) his company vehicle, (iv) the vesting of 3,000 shares of restricted stock and (v) the vesting of 14,820 restricted stock units provided that such restricted stock units will be settled in four substantially equal annual installments beginning in March 2017 in accordance with the original vesting schedule. All other restricted stock and restricted stock unit awards granted to Mr. Kirtley were forfeited and terminated.

Under the Separation Agreement, Mr. Kirtley is subject to certain covenants regarding confidentiality, non-solicitation, non-competition, trade secrets, unfair competition and inventions. The Separation Agreement also contains customary waiver and release provisions pursuant to which Mr. Kirtley waived, released and discharged us and certain other related parties from any and all claims that Mr. Kirtley may have had against us or such other parties as of the date of the Separation Agreement.

The preceding summary of the Separation Agreement is qualified in its entirety by reference to the full text of such agreement, a copy of which is attached as Exhibit 10.1 hereto and incorporated herein by reference.

Table of Contents

ITEM 6. EXHIBITS

Exhibit Number	Description
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).
3.3	Certificate of Amendment No. 2 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 23, 2013).
3.4	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
3.5	First Amendment to the Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 23, 2013).
3.6	Second Amendment to the Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company on May 2, 2014).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.5	Indenture, dated as of April 21, 2015, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of the Company’s 6.625% Senior Notes due 2023) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 21, 2015).
4.6	Indenture, dated as of October 14, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of Gulfport Energy Corporation’s 6.000% Senior Notes due 2024) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File. No. 000-19514, filed by the Company with the SEC on October 19, 2016).
4.7	Registration Rights Agreement, dated as of October 14, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC and Scotia Capital (USA) Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 to the Form 8-K, File. No. 000-19514, filed by the Company with the SEC on October 19, 2016).
10.1*	Separation and Release Agreement by and between Gulfport Energy Corporation and Ross Kirtley entered into November 2, 2016.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.

31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
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 Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

*Filed herewith.

Table of Contents

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: November 3, 2016

GULFPORT ENERGY
CORPORATION

By: /s/ Keri Crowell
Keri Crowell
Chief Accounting Officer