UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2017 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)**
3001 Quail Springs Parkway Oklahoma City, Oklahoma	**73134**
(Address of Principal Executive Offices)	**(Zip Code)**

(405) 252-4600
(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 ☒ 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 ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Emerging growth company ☐

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

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

As of August 1, 2017, 182,854,921 shares of the registrant’s common stock were outstanding.

GULFPORT ENERGY CORPORATION
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GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2017	December 31, 2016
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 117,555	$ 1,275,875
Restricted cash	—	185,000
Accounts receivable—oil and natural gas	164,154	136,761
Accounts receivable—related parties	185	16
Prepaid expenses and other current assets	4,279	3,135
Short-term derivative instruments	46,416	3,488
Total current assets	332,589	1,604,275
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $3,109,143 and $1,580,305 excluded from amortization in 2017 and 2016, respectively	8,500,790	6,071,920
Other property and equipment	79,521	68,986
Accumulated depletion, depreciation, amortization and impairment	(3,937,656)	(3,789,780)
Property and equipment, net	4,642,655	2,351,126
Other assets:		
Equity investments	256,265	243,920
Long-term derivative instruments	19,761	5,696
Deferred tax asset	4,692	4,692
Inventories	19,303	4,504
Other assets	18,890	8,932
Total other assets	318,911	267,744
Total assets	$ 5,294,155	$ 4,223,145
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 495,734	$ 265,124
Asset retirement obligation—current	195	195
Short-term derivative instruments	28,106	119,219
Current maturities of long-term debt	595	276
Total current liabilities	524,630	384,814
Long-term derivative instrument	8,198	26,759
Asset retirement obligation—long-term	43,934	34,081
Long-term debt, net of current maturities	1,802,554	1,593,599
Total liabilities	2,379,316	2,039,253
Commitments and contingencies (Note 9)		
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:		
Common stock - $.01 par value, 200,000,000 authorized, 182,854,921 issued and outstanding at June 30, 2017 and 158,829,816 at December 31, 2016	1,828	1,588
Paid-in capital	4,410,871	3,946,442
Accumulated other comprehensive loss	(47,171)	(53,058)
Retained deficit	(1,450,689)	(1,711,080)
Total stockholders' equity	2,914,839	2,183,892
Total liabilities and stockholders' equity	$ 5,294,155	$ 4,223,145

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(In thousands, except share data)			
Revenues:				
Natural gas sales	$ 205,367	$ 75,761	$ 383,204	$ 149,855
Oil and condensate sales	29,468	23,161	53,879	39,000
Natural gas liquid sales	24,247	10,311	55,426	19,604
Net gain (loss) on natural gas, oil, and NGL derivatives	64,871	(137,392)	164,448	(79,657)
	323,953	(28,159)	656,957	128,802
Costs and expenses:				
Lease operating expenses	20,721	14,661	40,024	31,318
Production taxes	5,139	2,856	9,045	5,967
Midstream gathering and processing	58,945	39,349	106,886	77,001
Depreciation, depletion and amortization	82,246	55,652	148,237	121,129
Impairment of oil and natural gas properties	—	170,621	—	389,612
General and administrative	12,257	11,854	24,857	22,474
Accretion expense	410	261	692	508
Acquisition expense	1,060	—	2,358	—
	180,778	295,254	332,099	648,009
INCOME (LOSS) FROM OPERATIONS	143,175	(323,413)	324,858	(519,207)
OTHER (INCOME) EXPENSE:				
Interest expense	24,188	16,082	47,667	32,105
Interest income	(48)	(391)	(890)	(485)
Loss from equity method investments, net	13,301	836	18,208	31,573
Other income	(202)	(7)	(518)	(9)
	37,239	16,520	64,467	63,184
INCOME (LOSS) BEFORE INCOME TAXES	105,936	(339,933)	260,391	(582,391)
INCOME TAX BENEFIT	—	(157)	—	(348)
NET INCOME (LOSS)	$ 105,936	$ (339,776)	$ 260,391	$ (582,043)
NET INCOME (LOSS) PER COMMON SHARE:				
Basic	$ 0.58	$ (2.71)	$ 1.47	$ (4.91)
Diluted	$ 0.58	$ (2.71)	$ 1.47	$ (4.91)
Weighted average common shares outstanding—Basic	182,840,213	125,343,723	176,591,166	118,426,654
Weighted average common shares outstanding—Diluted	182,841,730	125,343,723	176,842,239	118,426,654

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Net income (loss)	$ 105,936	$ (339,776)	$ 260,391	$ (582,043)
Foreign currency translation adjustment	4,514	(684)	5,887	8,374
Other comprehensive income (loss)	4,514	(684)	5,887	8,374
Comprehensive income (loss)	$ 110,450	$ (340,460)	$ 266,278	$ (573,669)

See accompanying notes to consolidated financial statements.

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

	Common Stock		Paid-in Capital	Accumulated Other Comprehensive Income (loss)	Retained Deficit	Total Stockholders' Equity
	Shares	Amount				
	(In thousands, except share data)					
Balance at January 1, 2017	158,829,816	$ 1,588	$3,946,442	$ (53,058)	$(1,711,080)	$2,183,892
Net income	—	—	—	—	260,391	260,391
Other Comprehensive Income	—	—	—	5,887	—	5,887
Stock Compensation	—	—	5,233	—	—	5,233
Issuance of Common Stock for the Vitruvian Acquisition, net of related expenses	23,852,117	239	459,197	—	—	459,436
Issuance of Restricted Stock	172,988	1	(1)	—	—	—
Balance at June 30, 2017	182,854,921	$ 1,828	$4,410,871	$ (47,171)	$(1,450,689)	$2,914,839
Balance at January 1, 2016	108,322,250	$ 1,082	$2,824,303	$ (55,177)	$ (731,371)	$2,038,837
Net loss	—	—	—	—	(582,043)	(582,043)
Other Comprehensive Income	—	—	—	8,374	—	8,374
Stock Compensation	—	—	6,561	—	—	6,561
Issuance of Common Stock in public offerings, net of related expenses	16,905,000	169	411,542	—	—	411,711
Issuance of Restricted Stock	137,916	2	(2)	—	—	—
Balance at June 30, 2016	125,365,166	$ 1,253	$3,242,404	$ (46,803)	$(1,313,414)	$1,883,440

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six months ended June 30, 2017	Six months ended June 30, 2016
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$ 260,391	$ (582,043)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Accretion of discount—Asset Retirement Obligation	692	508
Depletion, depreciation and amortization	148,237	121,129
Impairment of oil and natural gas properties	—	389,612
Stock-based compensation expense	3,140	3,936
Loss from equity investments	18,662	31,732
Change in fair value of derivative instruments	(166,667)	206,370
Deferred income tax expense (benefit)	—	(348)
Amortization of loan commitment fees	2,288	1,921
Amortization of note discount and premium	—	(1,135)
Changes in operating assets and liabilities:		
Increase in accounts receivable	(27,393)	(19,590)
Increase in accounts receivable—related party	(169)	(7)
Increase in prepaid expenses	(1,144)	(3,877)
Increase in other assets	(4,425)	—
Increase (decrease) in accounts payable, accrued liabilities and other	53,385	(5,412)
Settlement of asset retirement obligation	(344)	(72)
Net cash provided by operating activities	286,653	142,724
Cash flows from investing activities:		
Deductions to cash held in escrow	—	8
Additions to other property and equipment	(10,645)	(13,410)
Acquisition of oil and natural gas properties	(1,339,222)	—
Additions to oil and natural gas properties	(460,765)	(257,222)
Proceeds from sale of oil and natural gas properties	3,730	1,612
Funding of restricted cash	185,000	—
Contributions to equity method investments	(24,151)	(16,690)
Distributions from equity method investments	1,429	4,658
Net cash used in investing activities	(1,644,624)	(281,044)
Cash flows from financing activities:		
Principal payments on borrowings	(47)	(1,685)
Borrowings on line of credit	210,000	—
Borrowings on term loan	2,951	11,962
Debt issuance costs and loan commitment fees	(7,889)	(205)
Proceeds from issuance of common stock, net of offering costs	(5,364)	411,711
Net cash provided by financing activities	199,651	421,783
Net (decrease) increase in cash and cash equivalents	(1,158,320)	283,463
Cash and cash equivalents at beginning of period	1,275,875	112,974
Cash and cash equivalents at end of period	$ 117,555	$ 396,437
Supplemental disclosure of cash flow information:		
Interest payments	$ 48,118	$ 35,026
Income tax payments	$ —	$ —
Supplemental disclosure of non-cash transactions:		
Capitalized stock based compensation	$ 2,093	$ 2,625
Asset retirement obligation capitalized	$ 9,505	$ 3,195
Interest capitalized	$ 6,699	$ 3,707
Foreign currency translation gain on equity method investments	$ 5,887	$ 8,374

See accompanying notes to consolidated financial statements.

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 six month periods ended June 30, 2017 are not necessarily indicative of the results expected for the full year.

1. ACQUISITIONS

Vitruvian Acquisition

In December 2016, the Company, through its wholly-owned subsidiary Gulfport MidCon LLC ("Gulfport MidCon") (formerly known as SCOOP Acquisition Company, LLC), entered into an agreement to acquire certain assets of Vitruvian II Woodford, LLC ("Vitruvian"), an unrelated third-party seller (the "Vitruvian Acquisition"). The assets included in the Vitruvian Acquisition include 46,400 net surface acres located in Grady, Stephens and Garvin Counties, Oklahoma. On February 17, 2017, the Company completed the Vitruvian Acquisition for a total initial purchase price of approximately $1.85 billion, consisting of $1.35 billion in cash, subject to certain adjustments, and approximately 23.9 million shares of the Company's common stock (of which approximately 5.2 million shares were placed in an indemnity escrow). The cash portion of the purchase price was funded with the net proceeds from the December 2016 common stock and senior note offerings and cash on hand. Acquisition costs of $1.1 million and $2.4 million were incurred during the three and six months ended June 30, 2017, respectively, related to the Vitruvian Acquisition.

Allocation of Purchase Price

The Vitruvian 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 February 17, 2017 acquisition date. The fair value of the assets acquired and liabilities assumed was estimated using assumptions that represent Level 3 inputs. See Note 11 for additional discussion of the measurement inputs.

The Company estimated that the consideration paid in the Vitruvian 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 Vitruvian Acquisition to acquire the properties and the fair value amount of the assets acquired as of February 17, 2017. Both the consideration paid and the fair value assigned to the assets is preliminary and subject to adjustment.

		(In thousands)
Consideration:		
Cash, net of purchase price adjustments	$	1,354,093
Fair value of Gulfport’s common stock issued		464,639
Total Consideration	$	1,818,732
Estimated Fair value of identifiable assets acquired and liabilities assumed:		
Oil and natural gas properties		
Proved properties	$	362,264
Unproved properties		1,462,957
Asset retirement obligations		(6,489)
Total fair value of net identifiable assets acquired	$	1,818,732

The equity consideration included in the initial purchase price was based on an equity offering price of $20.96 on December 15, 2016. The decrease in the price of Gulfport’s common stock from $20.96 on December 15, 2016 to $19.48 on February 17, 2017 resulted in a decrease to the fair value of the total consideration paid as compared to the initial purchase price of approximately $35.3 million, which resulted in a closing date fair value lower than the initial purchase price.

Post-Acquisition Operating Results

For the three months ended June 30, 2017 and the period from the acquisition date of February 17, 2017 to June 30, 2017, the assets acquired in the Vitruvian Acquisition have contributed the following amounts of revenue to the Company’s consolidated statements of operations. The amount of net income contributed by the assets acquired is not presented below as it is impracticable to calculate due to the Company integrating the acquired assets into its overall operations using the full cost method of accounting.

	Three months ended June 30, 2017	Period from February 17, 2017 to June 30, 2017
	(In thousands)	
Revenue	$ 51,069	$ 77,997

Pro Forma Information (Unaudited)

The following unaudited pro forma combined financial information presents the Company’s results as though the Vitruvian Acquisition had been completed at January 1, 2016. The pro forma combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have actually occurred had the Vitruvian Acquisition taken place on January 1, 2016; furthermore, the financial information is not intended to be a projection of future results.

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(In thousands, except share data)			
Pro forma revenue	$ 323,953	$ (28,012)	$ 692,856	$ 175,700
Pro forma net income (loss)	$ 105,936	$ (461,007)	$ 281,817	$ (735,214)
Pro forma earnings (loss) per share (basic)	$ 0.58	$ (3.09)	$ 1.60	$ (5.17)
Pro forma earnings (loss) per share (diluted)	$ 0.58	$ (3.09)	$ 1.59	$ (5.17)

2. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of June 30, 2017 and December 31, 2016 are as follows:

	June 30, 2017	December 31, 2016
	(In thousands)	
Oil and natural gas properties	$ 8,500,790	$ 6,071,920
Office furniture and fixtures	30,227	21,204
Building	44,474	42,530
Land	4,820	5,252
Total property and equipment	8,580,311	6,140,906
Accumulated depletion, depreciation, amortization and impairment	(3,937,656)	(3,789,780)
Property and equipment, net	$ 4,642,655	$ 2,351,126

Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and natural gas properties. At June 30, 2017, the calculated ceiling was greater than the net book value of the Company’s oil and natural gas properties, thus no ceiling test impairment was required for the six months ended June 30, 2017. An impairment of $170.6 million and $389.6 million was required for oil and natural gas properties for the three and six months ended June 30, 2016, respectively.

Included in oil and natural gas properties at June 30, 2017 is the cumulative capitalization of $146.6 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 $8.3 million and $16.7 million for the three and six months ended June 30, 2017, respectively, and $7.9 million and $15.0 million for the three and six months ended June 30, 2016, respectively.

The following table summarizes the Company’s non-producing properties excluded from amortization by area at June 30, 2017:

	June 30, 2017
	(In thousands)
Utica	$ 1,614,824
MidCon	1,491,144
Niobrara	2,173
Southern Louisiana	536
Bakken	98
Other	368
	$ 3,109,143

At December 31, 2016, approximately $1.6 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 six months ended June 30, 2017 and 2016 is as follows:

	June 30, 2017	June 30, 2016
	(In thousands)	
Asset retirement obligation, beginning of period	$ 34,276	$ 26,437
Liabilities incurred	9,505	3,195
Liabilities settled	(344)	(72)
Accretion expense	692	508
Asset retirement obligation as of end of period	44,129	30,068
Less current portion	195	75
Asset retirement obligation, long-term	$ 43,934	$ 29,993

3. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of June 30, 2017 and December 31, 2016:

		Carrying value		(Income) loss from equity method investments			
				Three months ended June 30,		Six months ended June 30,	
	Approximate ownership %	June 30, 2017	December 31, 2016	2017	2016	2017	2016
				(In thousands)			
Investment in Tatex Thailand II, LLC	23.5%	$ —	$ —	$ (211)	$ —	$ (454)	$ (159)
Investment in Tatex Thailand III, LLC	17.9%	—	—	—	—	—	—
Investment in Grizzly Oil Sands ULC	24.9999%	51,604	45,213	208	763	573	24,448
Investment in Timber Wolf Terminals LLC	50.0%	987	991	—	1	4	4
Investment in Windsor Midstream LLC	22.5%	270	25,749	25,545	(2,881)	25,234	(3,048)
Investment in Stingray Cementing LLC(1)	—%	—	1,920	77	78	205	108
Investment in Blackhawk Midstream LLC	48.5%	—	—	—	—	—	—
Investment in Stingray Energy Services LLC(1)	—%	—	4,215	85	139	282	641
Investment in Sturgeon Acquisitions LLC(1)	—%	—	20,526	(139)	134	(71)	511
Investment in Mammoth Energy Services, Inc.(1)	25.1%	150,458	111,717	(12,181)	2,543	(10,023)	9,009
Investment in Strike Force Midstream LLC	25.0%	52,946	33,589	(83)	59	2,458	59
		$ 256,265	$ 243,920	$ 13,301	$ 836	$ 18,208	$ 31,573

(1) On June 5, 2017, Mammoth Energy Services, Inc. acquired Stingray Cementing LLC, Stingray Energy Services LLC and Sturgeon Acquisitions LLC. See below under *Mammoth Energy Partners LP/Mammoth Energy Services, Inc.* for information regarding these transactions.

The tables below summarize financial information for the Company's equity investments as of June 30, 2017 and December 31, 2016.

Summarized balance sheet information:

	June 30, 2017	December 31, 2016
	(In thousands)	
Current assets	$ 145,857	$ 148,733
Noncurrent assets	$ 1,414,377	$ 1,305,407
Current liabilities	$ 102,011	$ 57,173
Noncurrent liabilities	$ 137,215	$ 67,680

Summarized results of operations:

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Gross revenue	$ 99,640	$ 86,732	$ 194,118	$ 130,039
Net loss	$ (67,336)	$ (560)	$ (92,675)	$ (25,868)

Tatex Thailand II, LLC

The Company has an indirect ownership interest in Tatex Thailand II, LLC ("Tatex II"). Tatex II holds an 8.5% interest in 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 180,000 acres which includes the Phu Horm Field. The Company received $0.5 million and $0.2 million in distributions from Tatex II during the six months ended June 30, 2017 and 2016, respectively.

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, together with Tatex III, 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 June 30, 2017, 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 as such, 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 loss from equity method investments, net in the consolidated statements of operations. As of and during the period ended June 30, 2017, 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 six months ended June 30, 2017, Gulfport paid $1.2 million in cash calls. Grizzly's functional currency is the Canadian dollar. The Company's investment in Grizzly was increased by $4.5 million and $5.8 million as a result of a foreign currency translation gain for the three and six months ended June 30, 2017, respectively. The Company's investment in Grizzly was decreased by $0.6 million as a result of a foreign currency translation loss and increased by $9.7 million as a result of a foreign currency translation gain for the three and six months ended June 30, 2016, respectively.

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

At June 30, 2017, the Company held a 22.5% interest in Windsor Midstream LLC (“Midstream”), an entity controlled and managed by an unrelated third party. Midstream previously 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”). As a result of the sale of Coronado to EnLink, Midstream received common units of EnLink, which were subsequently sold by Midstream. During the six months ended June 30, 2017, the Company noted that Midstream had not recorded certain activity and fair value treatment of Midstream's investment in EnLink common units in a timely manner. The corresponding effect of this treatment was immaterial to the Company's previously issued financial statements and the recording of the correction in the current periods' financial statements was not material to the Company's estimated net income for the current full fiscal year. For the three and six months ended June 30, 2017, approximately $23.4 million of the loss from equity method investments, net was related to the out-of-period activity associated with the accounting for Midstream's investment in EnLink common units. The Company received $0.2 million and $4.9 million in distributions from Midstream during the six months ended June 30, 2017 and 2016, respectively.

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. On June 5, 2017, Mammoth Energy Services, Inc. (“Mammoth Energy”) acquired Stingray Cementing. See below under *Mammoth Energy Partners LP/Mammoth Energy Services, Inc.* for information regarding this transaction.

Blackhawk Midstream LLC

During 2012, the Company invested in Blackhawk Midstream LLC (“Blackhawk”). Blackhawk coordinated gathering, compression, processing and marketing activities for the Company in connection with the development of its Utica Shale acreage. Blackhawk does not have any current activities.

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. On June 5, 2017, Mammoth Energy acquired Stingray Energy. See below under *Mammoth Energy Partners LP/Mammoth Energy Services, Inc.* for information regarding this transaction.

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. On June 5, 2017, Mammoth Energy acquired Sturgeon. See below under *Mammoth Energy Partners LP/Mammoth Energy Services, Inc.* for information regarding this transaction.

Mammoth Energy Partners LP/Mammoth Energy Services, Inc.

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 converted from a limited partnership into a limited liability company named Mammoth Energy Partners LLC (“Mammoth LLC”) and the Company and the other members of Mammoth LLC contributed their interests in Mammoth LLC to Mammoth Energy. The Company received 9,150,000 shares of Mammoth Energy common stock in return for its contribution. Following the contribution, Mammoth Energy completed its initial public offering (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 the Company for which it received net proceeds of $1.1 million.

On June 5, 2017, the Company contributed all of its membership interests in Sturgeon (which owns Taylor Frac, LLC, Taylor Real Estate Investments, LLC and South River Road, LLC), Stingray Energy and Stingray Cementing to Mammoth Energy in exchange for approximately 2.0 million shares of Mammoth Energy common stock. As of June 30, 2017, the Company held approximately 25.1% of Mammoth Energy's outstanding common stock. The Company accounted for the transactions as a sale of financial assets under FASB ASC 860. The Company valued the shares of Mammoth Energy common stock it received in the transactions at $18.50 per share, which was the closing price of Mammoth Energy common stock on June 5, 2017. The Company recognized a gain of $12.5 million from the transactions, which is included in loss from equity method investments, net in the accompanying consolidated statements of operations.

The Company's investment in Mammoth Energy was increased by a $0.02 million and $0.1 million foreign currency gain resulting from Mammoth Energy's foreign subsidiary for the three and six months ended June 30, 2017, respectively. The Company's investment in Mammoth Energy was decreased by a $0.1 million and $1.3 million foreign currency loss resulting from Mammoth Energy's foreign subsidiary for the three and six months ended June 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 six months ended June 30, 2017, Gulfport paid $23.0 million in cash calls to Strike Force and received distributions of $1.2 million from Strike Force. During the six months ended June 30, 2016, Gulfport paid $3.0 million in cash calls to Strike Force.

The Company accounted for its initial 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 11 - 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 June 30, 2017, the Company held variable interests in the following variable interest entities ("VIEs"), but was not the primary beneficiary: 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. Prior to Mammoth Energy's IPO, Mammoth LLC was considered a variable interest entity. As a result of the Company's contribution of its interest in Mammoth LLC to Mammoth Energy in exchange for Mammoth Energy common stock and Mammoth Energy's IPO, the Company determined that it no longer held an interest in a variable interest entity. Prior to the contribution of Stingray Energy, Stingray Cementing and Sturgeon to Mammoth Energy, these entities were considered VIEs. As a result of the Company's contribution of its membership interests in Stingray Energy, Stingray Cementing and Sturgeon to Mammoth Energy in exchange for Mammoth Energy common stock, the Company determined that it no longer held an interest in a variable interest 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. LONG-TERM DEBT

Long-term debt consisted of the following items as of June 30, 2017 and December 31, 2016:

	June 30, 2017	December 31, 2016
	(In thousands)	
Revolving credit agreement (1)	$ 210,000	$ —
7.75% senior unsecured notes due 2020 (2)	—	—
6.625% senior unsecured notes due 2023 (3)	350,000	350,000
6.000% senior unsecured notes due 2024 (4)	650,000	650,000
6.375% senior unsecured notes due 2025 (5)	600,000	600,000
Net unamortized debt issuance costs (6)	(30,804)	(27,174)
Construction loan (7)	23,953	21,049
Less: current maturities of long term debt	(595)	(276)
Debt reflected as long term	$ 1,802,554	$ 1,593,599

The Company capitalized approximately $3.6 million and $6.7 million in interest expense to undeveloped oil and natural gas properties during the three and six months ended June 30, 2017, respectively. The Company capitalized approximately $1.4 million and $3.0 million in interest expense to undeveloped oil and natural gas properties during the three and six months ended June 30, 2016, respectively. During the three and six months ended June 30, 2016, the Company also capitalized approximately $0.4 million and $0.7 million, respectively, in interest expense related to building construction. Construction on the building was completed in December 2016 and, as such, the Company did not capitalize any interest expense related to building construction for the three and six months ended June 30, 2017.

(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 December 13, 2016, the Company further amended its revolving credit facility to, among other things, (a) reset the maturity date to December 31, 2021, (b) adjust lenders, (c) increase the basket for unsecured debt issuances to $1.6 billion, (d) increase the interest rates by 50 basis points, (e) increase the mortgage requirement to 85% (from 80%), and (f) add deposit account control agreement language. On March 29, 2017, the Company further amended its revolving credit facility to, among other things, amend the definition of the term EBITDAX to permit pro forma treatment of acquisitions that involve the payment of consideration by Gulfport and its subsidiaries in excess of $50.0 million and of dispositions of property or series of related dispositions of properties that yields gross proceeds to Gulfport or any of its subsidiaries in excess of $50.0 million. On May 4, 2017, the revolving credit facility was further amended to increase the borrowing base from $700.0 million to $1.0 billion, adjust certain of the Company's investment baskets and add five additional banks to the syndicate.

As of June 30, 2017, $210.0 million was outstanding under the revolving credit facility and the total availability for future borrowings under this facility, after giving effect to an aggregate of $237.5 million of letters of credit, was $552.5 million. The Company's wholly-owned subsidiaries have guaranteed the obligations of the Company under the revolving credit facility.

Advances under the 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 1.00% to 2.00%, 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 2.00% to 3.00%, 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 service that displays on average London interbank offered rate as determined by ICE Benchmark Administration (or any other person that takes over 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. At June 30, 2017, amounts borrowed under the credit facility bore interest at the eurodollar rate (3.46%).

The 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 affiliates.

The negative covenants are subject to certain exceptions as specified in the revolving credit facility. The revolving credit facility also contains certain affirmative covenants, including, but not limited to the following financial covenants:

(i) 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 investments 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 disposition 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

(ii) 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 all covenants at June 30, 2017.

(2) On October 17, 2012, the Company issued $250.0 million in aggregate principal amount of 7.75% Senior 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 7.75% Senior 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 7.75% Senior 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 October 2016, the Company repurchased (in a cash tender offer) or redeemed all of the 2020 Notes, of which $600.0 million in aggregate principal amount was then outstanding, with the net proceeds from the issuance of its 6.000% Senior Notes due 2024 (the "2024 Notes") discussed below and cash on hand, and the indenture governing the 2020 Notes was fully satisfied and discharged.

(3) On April 21, 2015, the Company issued $350.0 million in aggregate principal amount of 6.625% Senior Notes due 2023 (the "2023 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. In October 2015, the 2023 Notes were exchanged for a new issue of substantially identical debt securities registered under the Securities Act. Pursuant to the indenture relating to the 2023 Notes, interest on the 2023 Notes accrues at a rate of 6.625% per annum on the outstanding principal amount thereof, payable semi-annually on May 1 and November 1 of each year. The 2023 Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of the Company’s future unrestricted subsidiaries.

(4) On October 14, 2016, the Company issued the 2024 Notes in aggregate principal amount of $650.0 million. The 2024 Notes were issued under an indenture, dated as of October 14, 2016, among the Company, the subsidiary guarantors party thereto and the senior note indenture trustee (the “2024 Indenture”), 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 “2024 Notes Offering”). Under the 2024 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 $638.9 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.

(5) On December 21, 2016, the Company issued $600.0 million in aggregate principal amount of 6.375% Senior Notes due 2025 (the “2025 Notes”). The 2025 Notes were issued under an indenture, dated as of December 21, 2016, among the Company, the subsidiary guarantors party thereto and the senior note indenture trustee (the “2025 Indenture”), to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. Under the 2025 Indenture, interest on the 2025 Notes accrues at a rate of 6.375% per annum on the outstanding principal amount thereof from December 21, 2016, payable semi-annually on May 15 and November 15 of each year, commencing on May 15, 2017. The 2025 Notes will mature on May 15, 2025. The Company received approximately $584.7 million in net proceeds from the offering of the 2025 Notes, which was used, together with the net proceeds from the Company’s December 2016 common stock offering and cash on hand, to fund the cash portion of the purchase price for the Vitruvian Acquisition. See “Note 1 – Acquisitions” for additional discussion of the Vitruvian Acquisition.

(6) In accordance with ASU 2015-03, loan issuance costs related to the 2023 Notes, the 2024 Notes and the 2025 Notes (collectively the “Notes”) have been presented as a reduction to the Notes. At June 30, 2017, total unamortized debt issuance costs were $5.6 million for the 2023 Notes, $10.5 million for the 2024 Notes and $14.6 million for the 2025 Notes. In addition, loan commitment fee costs for the construction loan agreement described immediately below were $0.1 million at June 30, 2017.

(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, which was substantially completed in December 2016. The Construction Loan allows for maximum principal borrowings of $24.5 million and required the Company to fund 30% of the cost of the construction before any funds could 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 was 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 June 30, 2017, the total borrowings under the Construction Loan were approximately $24.0 million.

6. COMMON STOCK AND CHANGES IN CAPITALIZATION

Issuance 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 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 used the net proceeds from this offering primarily to fund a portion of its 2017 capital development plan and for general corporate purposes.

On February 17, 2017, the Company completed the Vitruvian Acquisition for a total initial purchase price of approximately $1.85 billion, consisting of $1.35 billion in cash, subject to certain adjustments, and approximately 23.9 million shares of the Company's common stock (of which approximately 5.2 million shares are subject to the indemnity escrow). See "Note 1 - Acquisitions" for additional discussion of the Vitruvian Acquisition.

7. STOCK-BASED COMPENSATION

During the three and six months ended June 30, 2017, the Company's stock-based compensation cost was $2.6 million and $5.2 million, respectively, of which the Company capitalized $1.1 million and $2.1 million, respectively, relating to its exploration and development efforts. During the three and six months ended June 30, 2016, the Company's stock-based compensation cost was $3.3 million and $6.6 million, respectively, of which the Company capitalized $1.3 million and $2.6 million, respectively, relating to its exploration and development efforts.

The following table summarizes restricted stock activity for the six months ended June 30, 2017:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of January 1, 2017	613,056	$ 32.90
Granted	525,808	17.31
Vested	(172,988)	32.06
Forfeited	(66,661)	31.18
Unvested shares as of June 30, 2017	899,215	$ 24.08

Unrecognized compensation expense as of June 30, 2017 related to restricted shares was $16.1 million. The expense is expected to be recognized over a weighted average period of 1.59 years.

8. EARNINGS PER SHARE

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

	Three months ended June 30,					
	2017			2016		
	Income	Shares	Per Share	(Loss)	Shares	Per Share
	(In thousands, except share data)					
Basic:						
Net income (loss)	$ 105,936	182,840,213	$ 0.58	$ (339,776)	125,343,723	$ (2.71)
Effect of dilutive securities:						
Stock options and awards	—	1,517		—	—	
Diluted:		—				
Net income (loss)	$ 105,936	182,841,730	$ 0.58	$ (339,776)	125,343,723	$ (2.71)

	Six months ended June 30,					
	2017			2016		
	Income	Shares	Per Share	(Loss)	Shares	Per Share
	(In thousands, except share data)					
Basic:						
Net income (loss)	$ 260,391	176,591,166	$ 1.47	$ (582,043)	118,426,654	$ (4.91)
Effect of dilutive securities:						
Stock options and awards	—	251,073		—	—	
Diluted:		—				
Net income (loss)	$ 260,391	176,842,239	$ 1.47	$ (582,043)	118,426,654	$ (4.91)

There were 573,187 and 558,894 shares of common stock that were considered anti-dilutive for the three months and six months ended June 30, 2016, respectively.

9. 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 June 30, 2017, the plugging and abandonment trust totaled approximately $3.1 million. At June 30, 2017, the Company had plugged 513 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its 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 June 30, 2017 were as follows:

	(In thousands)
Remaining 2017	$ 70
2018	54
Total	$ 124

Firm Transportation Commitments

The Company had approximately 2,930,000 MMBtu per day of firm sales contracted with third parties. The table below presents these commitments at June 30, 2017 as follows:

	(MMBtu per day)
Remaining 2017	728,000
2018	498,000
2019	579,000
2020	506,000
2021	371,000
Thereafter	248,000
Total	2,930,000

The Company also had approximately $3.8 billion of firm transportation contracted with third parties. The table below presents these commitments at June 30, 2017 as follows:

	(In thousands)
Remaining 2017	$ 105,871
2018	246,749
2019	243,389
2020	240,746
2021	239,786
Thereafter	2,705,270
Total	$ 3,781,811

Other Commitments

Effective October 1, 2014, the Company entered into a Sand Supply Agreement with Muskie Proppant LLC ("Muskie"), a subsidiary of Mammoth Energy, that expires on September 30, 2018. Pursuant to this agreement, as amended, 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 $0.7 million and $2.0 million related to non-utilization fees during the three months and six months ended June 30, 2016, respectively. The Company did not incur any non-utilization fees during the six months ended June 30, 2017.

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"), a subsidiary of Mammoth Energy, that expires on September 30, 2018. Pursuant to this agreement, as amended, 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.

Future minimum commitments under these agreements at June 30, 2017 are as follows:

	(In thousands)
Remaining 2017	$ 26,220
2018	39,330
Total	$ 65,550

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 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, 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 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. In March 2017, the United States Court of Appeals, Fifth Circuit issued its ruling. Subsequently, the Vermillion Parish case and Cameron Parish case have both had their respective stays lifted. On July 3, 2017, the Magistrate issued her Report and Recommendation on the Motion to Remand for the Vermillion Parish case, recommending that the plaintiffs' motion to remand be granted. On July 21, 2017, a group of the defendants in the Vermillion Parish case filed objections to the Magistrate's remand recommendation. No hearing on the remand motions has been set for the Cameron Parish case. 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.

10. DERIVATIVE INSTRUMENTS

Natural Gas, Oil and Natural Gas Liquids Derivative Instruments

The Company seeks to reduce its exposure to unfavorable changes in natural gas, oil 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. These contracts allow the Company to predict with greater certainty the effective natural gas, oil 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 the NYMEX Henry Hub for natural gas, Argus Louisiana Light Sweet Crude for oil, the NYMEX West Texas Intermediate for oil, and Mont Belvieu for propane and pentane. Below is a summary of the Company's open fixed price swap positions as of June 30, 2017.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
Remaining 2017	NYMEX Henry Hub	681,000	$ 3.20
2018	NYMEX Henry Hub	669,000	$ 3.08
2019	NYMEX Henry Hub	57,000	$ 3.10

	Location	Daily Volume (Bbls/day)	Weighted Average Price
Remaining 2017	ARGUS LLS	2,000	$ 53.12
Remaining 2017	NYMEX WTI	5,000	$ 54.89
2018	NYMEX WTI	1,000	$ 55.31

	Location	Daily Volume (Bbls/day)	Weighted Average Price
Remaining 2017	Mont Belvieu C3	3,000	$ 26.63
Remaining 2017	Mont Belvieu C5	250	$ 49.14

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 volumes.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
Remaining 2017	NYMEX Henry Hub	65,000	$ 3.11
2018	NYMEX Henry Hub	103,000	$ 3.25
2019	NYMEX Henry Hub	35,000	$ 3.11

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 2018 through December 2018. The option to extend the terms expires in December 2017. If executed, the Company would have additional fixed price swaps for 30,000 MMBtu per day with the option to double at a weighted average price of $3.36 per MMBtu and additional short call options for 30,000 MMBtu per day with the option to double at a weighted average ceiling price of $3.36 per MMBtu.

In addition, the Company has entered into natural gas basis swap positions, which settle on the pricing index to basis differential of NGPL Mid-Continent to NYMEX Henry Hub. As of June 30, 2017, the Company had the following natural gas basis swap positions for NGPL Mid-Continent.

	Location	Daily Volume (MMBtu/day)	Hedged Differential
Remaining 2017	NGPL Mid-Continent	50,000	$ (0.26)
2018	NGPL Mid-Continent	12,000	$ (0.26)

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 June 30, 2017 and December 31, 2016:

	June 30, 2017	December 31, 2016
	(In thousands)	
Short-term derivative instruments - asset	$ 46,416	$ 3,488
Long-term derivative instruments - asset	$ 19,761	$ 5,696
Short-term derivative instruments - liability	$ 28,106	$ 119,219
Long-term derivative instruments - liability	$ 8,198	$ 26,759

Gains and Losses

The following table presents the gain and loss recognized in Net gain (loss) on natural gas, oil and NGL derivatives in the accompanying consolidated statements of operations for the three and six months ended June 30, 2017 and 2016.

	Net gain (loss) on derivative instruments			
	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Natural gas derivatives	$ 56,668	$ (133,621)	$ 142,945	$ (76,621)
Oil derivatives	8,143	(2,628)	19,048	(1,346)
Natural gas liquids derivatives	60	(1,143)	2,455	(1,690)
Total	$ 64,871	$ (137,392)	$ 164,448	$ (79,657)

Offsetting of derivative assets and liabilities

As noted above, the Company records the fair value of derivative instruments on a gross basis. The following table presents the gross amounts of recognized derivative assets and liabilities in the consolidated balance sheets and the amounts that are subject to offsetting under master netting arrangements with counterparties, all at fair value.

	As of June 30, 2017		
	Gross Assets (Liabilities) Presented in the Consolidated Balance Sheets	Gross Amounts Subject to Master Netting Agreements	Net Amount
	(In thousands)		
Derivative assets	$ 66,177	$ (27,984)	$ 38,193
Derivative liabilities	$ (36,304)	$ 27,984	$ (8,320)

	As of December 31, 2016		
	Gross Assets (Liabilities) Presented in the Consolidated Balance Sheets	Gross Amounts Subject to Master Netting Agreements	Net Amount
	(In thousands)		
Derivative assets	$ 9,184	$ (9,184)	$ —
Derivative liabilities	$ (145,978)	$ 9,184	$ (136,794)

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. None of the Company's derivative instrument contracts contain credit-risk related contingent features. 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.

11. 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.

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 June 30, 2017 and December 31, 2016:

	June 30, 2017		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Derivative Instruments	$ —	$ 66,177	$ —
Liabilities:			
Derivative Instruments	$ —	$ 36,304	$ —

	December 31, 2016		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Derivative Instruments	$ —	$ 9,184	$ —
Liabilities:			
Derivative Instruments	$ —	$ 145,978	$ —

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 natural 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 natural 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. The asset retirement obligations assumed as part of the business combination were estimated using the same assumptions and methodology as described below. See Note 1 for further discussion of the Vitruvian Acquisition.

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 six months ended June 30, 2017 were approximately $9.5 million.

The fair value of the common stock received from Mammoth Energy in connection with the Company's contribution of all of its membership interests in Sturgeon, Stingray Energy and Stingray Cementing was estimated using Level 1 inputs, as the price per share was a quoted price in an active market for identical Mammoth Energy common shares.

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 initial 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.

12. FAIR VALUE OF FINANCIAL INSTRUMENTS

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 June 30, 2017, the carrying value of the outstanding debt represented by the Notes was approximately $1.6 billion, including the unamortized debt issuance cost of approximately $5.6 million related to the 2023 Notes, approximately $10.5 million related to the 2024 Notes and approximately $14.6 million related to the 2025 Notes. Based on the quoted market price, the fair value of the Notes was determined to be approximately $1.6 billion at June 30, 2017.

13. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

On October 17, 2012, December 21, 2012 and August 18, 2014, the Company issued the 2020 Notes in an aggregate of $600.0 million principal amount. The 2020 Notes were subsequently exchanged for substantially identical notes in the same aggregate principal amount that were registered under the Securities Act. In October 2016, the Company repurchased (in a cash tender offer) or redeemed all of the 2020 Notes, of which $600.0 million in aggregate principal amount was then outstanding, with the net proceeds from the issuance of the 2024 Notes discussed below and cash on hand.

On April 21, 2015, the Company issued $350.0 million in aggregate principal amount of the 2023 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. 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.

On October 14, 2016, the Company issued $650.0 million in aggregate principal amount of the 2024 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 net proceeds from the issuance of the 2024 Notes, together with cash on hand, were used to repurchase or redeem all of the then-outstanding 2020 Notes in October 2016.

On December 21, 2016, the Company issued $600.0 million in aggregate principal amount of the 2025 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 Company used the net proceeds from the issuance of the 2025 Notes, together with the net proceeds from the December 2016 underwritten offering of the Company's common stock and cash on hand, to fund the cash portion of the purchase price for the Vitruvian Acquisition.

The 2020 Notes were, and the 2023 Notes, the 2024 Notes and the 2025 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 were not, and the 2023 Notes, the 2024 Notes and the 2025 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.

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.

CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	June 30, 2017				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 72,062	$ 45,493	$ —	$ —	$ 117,555
Accounts receivable - oil and natural gas	121,565	42,589	—	—	164,154
Accounts receivable - related parties	185	—	—	—	185
Accounts receivable - intercompany	459,503	45,749	—	(505,252)	—
Prepaid expenses and other current assets	4,113	166	—	—	4,279
Short-term derivative instruments	46,416	—	—	—	46,416
Total current assets	703,844	133,997	—	(505,252)	332,589
Property and equipment:					
Oil and natural gas properties, full-cost accounting	6,142,757	2,358,762	—	(729)	8,500,790
Other property and equipment	79,478	43	—	—	79,521
Accumulated depletion, depreciation, amortization and impairment	(3,937,621)	(35)	—	—	(3,937,656)
Property and equipment, net	2,284,614	2,358,770	—	(729)	4,642,655
Other assets:					
Equity investments and investments in subsidiaries	2,179,931	52,946	51,605	(2,028,217)	256,265
Long-term derivative instruments	19,761	—	—	—	19,761
Deferred tax asset	4,692	—	—	—	4,692
Inventories	13,591	5,712	—	—	19,303
Other assets	10,834	8,056	—	—	18,890
Total other assets	2,228,809	66,714	51,605	(2,028,217)	318,911
Total assets	$ 5,217,267	$ 2,559,481	$ 51,605	$ (2,534,198)	$ 5,294,155
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$ 385,908	$ 109,826	$ —	$ —	$ 495,734
Accounts payable - intercompany	39,564	465,561	127	(505,252)	—
Asset retirement obligation - current	195	—	—	—	195
Derivative instruments	28,106	—	—	—	28,106
Current maturities of long-term debt	595	—	—	—	595
Total current liabilities	454,368	575,387	127	(505,252)	524,630
Long-term derivative instrument	8,198	—	—	—	8,198
Asset retirement obligation - long-term	37,308	6,626	—	—	43,934
Long-term debt, net of current maturities	1,802,554	—	—	—	1,802,554
Total liabilities	2,302,428	582,013	127	(505,252)	2,379,316
Stockholders' equity:					
Common stock	1,828	—	—	—	1,828
Paid-in capital	4,410,871	1,885,598	258,178	(2,143,776)	4,410,871
Accumulated other comprehensive (loss) income	(47,171)	—	(45,117)	45,117	(47,171)
Retained (deficit) earnings	(1,450,689)	91,870	(161,583)	69,713	(1,450,689)
Total stockholders' equity	2,914,839	1,977,468	51,478	(2,028,946)	2,914,839
Total liabilities and stockholders' equity	$ 5,217,267	$ 2,559,481	$ 51,605	$ (2,534,198)	$ 5,294,155

CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 1,273,882	$ 1,993	$ —	$ —	$ 1,275,875
Restricted Cash	185,000	—	—	—	185,000
Accounts receivable - oil and natural gas	137,087	37,496	—	(37,822)	136,761
Accounts receivable - related parties	16	—	—	—	16
Accounts receivable - intercompany	449,517	1,151	—	(450,668)	—
Prepaid expenses and other current assets	3,135	—	—	—	3,135
Short-term derivative instruments	3,488	—	—	—	3,488
Total current assets	2,052,125	40,640	—	(488,490)	1,604,275
Property and equipment:					
Oil and natural gas properties, full-cost accounting,	5,655,125	417,524	—	(729)	6,071,920
Other property and equipment	68,943	43	—	—	68,986
Accumulated depletion, depreciation, amortization and impairment	(3,789,746)	(34)	—	—	(3,789,780)
Property and equipment, net	1,934,322	417,533	—	(729)	2,351,126
Other assets:					
Equity investments and investments in subsidiaries	236,327	33,590	45,213	(71,210)	243,920
Long-term derivative instruments	5,696	—	—	—	5,696
Deferred tax asset	4,692	—	—	—	4,692
Inventories	3,095	1,409	—	—	4,504
Other assets	8,932	—	—	—	8,932
Total other assets	258,742	34,999	45,213	(71,210)	267,744
Total assets	$ 4,245,189	$ 493,172	$ 45,213	$ (560,429)	$ 4,223,145
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$ 255,966	$ 9,158	$ —	$ —	$ 265,124
Accounts payable - intercompany	31,202	457,163	126	(488,491)	—
Asset retirement obligation - current	195	—	—	—	195
Derivative instruments	119,219	—	—	—	119,219
Current maturities of long-term debt	276	—	—	—	276
Total current liabilities	406,858	466,321	126	(488,491)	384,814
Long-term derivative instrument	26,759	—	—	—	26,759
Asset retirement obligation - long-term	34,081	—	—	—	34,081
Long-term debt, net of current maturities	1,593,599	—	—	—	1,593,599
Total liabilities	2,061,297	466,321	126	(488,491)	2,039,253
Stockholders' equity:					
Common stock	1,588	—	—	—	1,588
Paid-in capital	3,946,442	33,822	257,026	(290,848)	3,946,442
Accumulated other comprehensive (loss) income	(53,058)	—	(50,931)	50,931	(53,058)
Retained (deficit) earnings	(1,711,080)	(6,971)	(161,008)	167,979	(1,711,080)
Total stockholders' equity	2,183,892	26,851	45,087	(71,938)	2,183,892
Total liabilities and stockholders' equity	$ 4,245,189	$ 493,172	$ 45,213	$ (560,429)	$ 4,223,145

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three months ended June 30, 2017				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ 249,353	$ 74,600	$ —	$ —	$ 323,953
Costs and expenses:					
Lease operating expenses	16,423	4,298	—	—	20,721
Production taxes	3,645	1,494	—	—	5,139
Midstream gathering and processing	42,291	16,654	—	—	58,945
Depreciation, depletion, and amortization	82,245	1	—	—	82,246
General and administrative	13,052	(796)	1	—	12,257
Accretion expense	291	119	—	—	410
Acquisition expense	5	1,055	—	—	1,060
	157,952	22,825	1	—	180,778
INCOME (LOSS) FROM OPERATIONS	91,401	51,775	(1)	—	143,175
OTHER (INCOME) EXPENSE:					
Interest expense	26,133	(1,945)	—	—	24,188
Interest income	(42)	(6)	—	—	(48)
(Income) loss from equity method investments and investments in subsidiaries	(40,475)	(83)	208	53,651	13,301
Other income	(151)	(51)	—	—	(202)
	(14,535)	(2,085)	208	53,651	37,239
INCOME (LOSS) BEFORE INCOME TAXES	105,936	53,860	(209)	(53,651)	105,936
INCOME TAX EXPENSE	—	—	—	—	—
NET INCOME (LOSS)	$ 105,936	$ 53,860	$ (209)	$ (53,651)	$ 105,936

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three months ended June 30, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ (28,580)	$ 421	$ —	$ —	$ (28,159)
Costs and expenses:					
Lease operating expenses	14,491	170	—	—	14,661
Production taxes	2,828	28	—	—	2,856
Midstream gathering and processing	39,242	107	—	—	39,349
Depreciation, depletion, and amortization	55,651	1	—	—	55,652
Impairment of oil and natural gas properties	170,621	—	—	—	170,621
General and administrative	11,846	8	—	—	11,854
Accretion expense	261	—	—	—	261
	294,940	314	—	—	295,254
(LOSS) INCOME FROM OPERATIONS	(323,520)	107	—	—	(323,413)
OTHER (INCOME) EXPENSE:					
Interest expense	16,082	—	—	—	16,082
Interest income	(391)	—	—	—	(391)
Loss (income) from equity method investments and investments in subsidiaries	722	59	762	(707)	836
Other income	—	(7)	—	—	(7)
	16,413	52	762	(707)	16,520
(LOSS) INCOME BEFORE INCOME TAXES	(339,933)	55	(762)	707	(339,933)
INCOME TAX BENEFIT	(157)	—	—	—	(157)
NET (LOSS) INCOME	$ (339,776)	$ 55	$ (762)	$ 707	$ (339,776)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Six months ended June 30, 2017				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ 521,794	$ 135,163	$ —	$ —	$ 656,957
Costs and expenses:					
Lease operating expenses	33,872	6,152	—	—	40,024
Production taxes	6,747	2,298	—	—	9,045
Midstream gathering and processing	80,015	26,871	—	—	106,886
Depreciation, depletion, and amortization	148,235	2	—	—	148,237
General and administrative	25,926	(1,071)	2	—	24,857
Accretion expense	573	119	—	—	692
Acquisition expense	5	2,353	—	—	2,358
	295,373	36,724	2	—	332,099
INCOME (LOSS) FROM OPERATIONS	226,421	98,439	(2)	—	324,858
OTHER (INCOME) EXPENSE:					
Interest expense	51,181	(3,514)	—	—	47,667
Interest income	(884)	(6)	—	—	(890)
(Income) loss from equity method investments and investments in subsidiaries	(83,089)	2,458	573	98,266	18,208
Other (income) expense	(1,178)	(240)	—	900	(518)
	(33,970)	(1,302)	573	99,166	64,467
INCOME (LOSS) BEFORE INCOME TAXES	260,391	99,741	(575)	(99,166)	260,391
INCOME TAX BENEFIT	—	—	—	—	—
NET INCOME (LOSS)	$ 260,391	$ 99,741	$ (575)	$ (99,166)	$ 260,391

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Six months ended June 30, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ 128,171	$ 631	$ —	$ —	$ 128,802
Costs and expenses:					
Lease operating expenses	30,963	355	—	—	31,318
Production taxes	5,915	52	—	—	5,967
Midstream gathering and processing	76,865	136	—	—	77,001
Depreciation, depletion, and amortization	121,127	2			121,129
Impairment of oil and natural gas properties	389,612	—	—	—	389,612
General and administrative	22,458	14	2	—	22,474
Accretion expense	508	—	—	—	508
	647,448	559	2	—	648,009
(LOSS) INCOME FROM OPERATIONS	(519,277)	72	(2)	—	(519,207)
OTHER (INCOME) EXPENSE:					
Interest expense	32,104	1	—	—	32,105
Interest income	(485)	—	—	—	(485)
Loss (income) from equity method investments and investments in subsidiaries	31,495	59	24,447	(24,428)	31,573
Other income	—	(9)	—	—	(9)
	63,114	51	24,447	(24,428)	63,184
(LOSS) INCOME BEFORE INCOME TAXES	(582,391)	21	(24,449)	24,428	(582,391)
INCOME TAX BENEFIT	(348)	—	—	—	(348)
NET (LOSS) INCOME	$ (582,043)	$ 21	$ (24,449)	$ 24,428	$ (582,043)

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

	Three months ended June 30, 2017				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$ 105,936	$ 53,860	$ (209)	$ (53,651)	$ 105,936
Foreign currency translation adjustment	4,514	19	4,495	(4,514)	4,514
Other comprehensive income (loss)	4,514	19	4,495	(4,514)	4,514
Comprehensive income (loss)	$ 110,450	$ 53,879	$ 4,286	$ (58,165)	$ 110,450

	Three months ended June 30, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net (loss) income	$ (339,776)	$ 55	$ (762)	$ 707	$ (339,776)
Foreign currency translation adjustment	(684)	—	(604)	604	(684)
Other comprehensive (loss) income	(684)	—	(604)	604	(684)
Comprehensive (loss) income	$ (340,460)	$ 55	$ (1,366)	$ 1,311	$ (340,460)

	Six months ended June 30, 2017				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$ 260,391	$ 99,741	$ (575)	$ (99,166)	$ 260,391
Foreign currency translation adjustment	5,887	74	5,813	(5,887)	5,887
Other comprehensive income (loss)	5,887	74	5,813	(5,887)	5,887
Comprehensive income (loss)	$ 266,278	$ 99,815	$ 5,238	$ (105,053)	$ 266,278

	Six months ended June 30, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net (loss) income	$ (582,043)	$ 21	$ (24,449)	$ 24,428	$ (582,043)
Foreign currency translation adjustment	8,374	—	9,669	(9,669)	8,374
Other comprehensive income (loss)	8,374	—	9,669	(9,669)	8,374
Comprehensive (loss) income	$ (573,669)	$ 21	$ (14,780)	$ 14,759	$ (573,669)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Six months ended June 30, 2017				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ 268,068	$ 18,585	$ 1	$ (1)	$ 286,653
Net cash (used in) provided by investing activities	(1,669,539)	(1,362,222)	(1,151)	1,388,288	(1,644,624)
Net cash provided by (used in) financing activities	199,651	1,387,137	1,150	(1,388,287)	199,651
Net (decrease) increase in cash and cash equivalents	(1,201,820)	43,500	—	—	(1,158,320)
Cash and cash equivalents at beginning of period	1,273,882	1,993	—	—	1,275,875
Cash and cash equivalents at end of period	$ 72,062	$ 45,493	$ —	$ —	$ 117,555

	Six months ended June 30, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by operating activities	$ 142,470	$ 254	$ —	$ —	$ 142,724
Net cash (used in) provided by investing activities	(281,044)	(25,500)	(13,690)	39,190	(281,044)
Net cash provided by (used in) financing activities	421,783	25,500	13,690	(39,190)	421,783
Net increase in cash and cash equivalents	283,209	254	—	—	283,463
Cash and cash equivalents at beginning of period	112,494	479	1	—	112,974
Cash and cash equivalents at end of period	$ 395,703	$ 733	$ 1	$ —	$ 396,437

14. 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 evaluating the impact of this ASU on its consolidated financial statements and working to identify any potential differences that would result from applying the requirements of the ASU to existing contracts and current accounting policies and practices. This evaluation includes the review of contracts for each revenue stream identified within the Company's business. The Company will conduct its contract review process throughout the remainder of 2017. Based on the continuing evaluation of its revenue streams, this ASU is not expected to have a material impact on the Company's net income. The Company is still in the process of determining whether or not it will use the retrospective method or the modified retrospective approach to implementation and does not plan to early adopt this guidance.

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. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements and related disclosures; however, based on the Company’s current operating leases, it is not expected to have a material impact.

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. The Company adopted the standard as of January 1, 2017. There was no impact on the Company’s consolidated financial statements because all current derivative instruments are not designated for hedge accounting.

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. The Company adopted the standard as of January 1, 2017. The Company has elected to recognize forfeitures of awards as they occur. The adoption of this standard did not have a material impact on the Company's 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 June 2016, the FASB issued ASU No. 2016-13, *Financial Instruments-Credit Losses: Measurement of Credit Losses on Financial Instruments*. This ASU amends guidance on reporting credit losses for assets held at amortized cost basis and available for sale debt securities. For assets held at amortized cost basis, this ASU eliminates the probable initial recognition threshold in current GAAP and instead, requires an entity to reflect its current estimate of all expected credit losses. The amendments affect loans, debt securities, trade receivables, net investments in leases, off balance sheet credit exposure, reinsurance receivables and any other financial assets not excluded from the scope that have the contractual right to receive cash. The Company is currently evaluating the impact this standard will have on its financial statements and related disclosures and does not anticipate it to have a material affect.

In August 2016, the FASB issued ASU No. 2016-15, *Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments.* This ASU provides guidance of eight specific cash flow issues. This ASU 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.

In December 2016, the FASB issued ASU No. 2016-20, *Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers*. This guidance updates narrow aspects of the guidance issued in Update 2014-09. 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 ASU on its consolidated financial statements.

In January 2017, the FASB issued ASU No. 2017-01, *Clarifying the Definition of a Business*. Under the current business combination guidance, there are three elements of a business: inputs, processes and outputs. The revised guidance adds an initial screen test to determine if substantially all of the fair value of the gross assets acquired is concentrated in a single asset or group of similar assets. If that screen is met, the set of assets is not a business. The new framework also specifies the minimum required inputs and processes necessary to be a business. 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 ASU on its consolidated financial statements.

15. SUBSEQUENT EVENTS

Derivatives

In July and August 2017, the Company entered into fixed price swaps for 2017 for approximately 66,000 MMBtu of natural gas per day at a weighted average price of $3.08 per MMBtu. For 2018, the Company entered into fixed price swaps for approximately 105,000 MMBtu of natural gas per day at a weighted average price of $2.94 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. In July and August 2017, the Company sold call options for 2019 for approximately 50,000 MMBtu of natural gas per day at a weighted average price of $3.04 per MMBtu. 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 volumes.

Registration Rights Agreements

As required under the terms of the registration rights agreements relating to the 2024 Notes and the 2025 Notes, on July 7, 2017, the Company filed with the SEC a Registration Statement on Form S-4 (the "Registration Statement"), relating to the exchange offers of the 2024 Notes and the 2025 Notes for substantially identical notes registered under the Securities Act (the "Exchange Offers"). The Registration Statement was declared effective by the SEC on August 4, 2017. The Company commenced the Exchange Offers on August 8, 2017 and expects to close the Exchange Offers in September of 2017.

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 (including those recently acquired from Vitruvian II Woodford, LLC) 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 primarily in Eastern Ohio and the SCOOP Woodford and SCOOP Springer plays in Oklahoma. In addition, among other interests, we hold an acreage position along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields, an acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, and an approximate 25.1% equity interest in Mammoth Energy Services, Inc., or Mammoth Energy, an oil field services company listed on the NASDAQ Global Select Market (TUSK). We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

2017 Operational and Other Highlights

- Production increased 56% to 94,490 net million cubic feet of natural gas equivalent, or MMcfe, for the three months ended June 30, 2017 from 60,492 MMcfe for the three months ended June 30, 2016. Our net daily production mix for the 2017 period was comprised of approximately 88% of natural gas, 8% of natural gas liquids, or NGLs, and 4% of oil.

- On February 17, 2017, we, through our wholly-owned subsidiary Gulfport MidCon LLC, or Gulfport MidCon (formerly known as SCOOP Acquisition Company, LLC), completed our acquisition, which we refer to as the Acquisition, of certain assets from Vitruvian II Woodford, LLC, an unrelated third-party seller, for a total purchase price of approximately $1.85 billion, consisting of $1.35 billion in cash, subject to certain adjustments and approximately 23.9 million shares of the Company's common stock (of which approximately 5.2 million shares were placed in an indemnity escrow). The Acquisition included approximately 46,000 net surface acres with multiple producing zones, including the Woodford and Springer formations in the South Central Oklahoma Oil Province, or SCOOP, resource play, in Grady, Stephens and Garvin Counties, Oklahoma.

- On June 5, 2017, we acquired approximately 2.0 million shares of Mammoth Energy common stock in connection with our contribution of all of our membership interests in Sturgeon Acquisitions LLC, Stingray Energy Services LLC and Stingray Cementing LLC, which we refer to as Sturgeon, Stingray Energy and Stingray Cementing, respectively, bringing our equity interest in Mammoth Energy to approximately 25.1%.

- During the three months ended June 30, 2017, we spud 28 gross (25.7 net) wells in the Utica Shale, participated in an additional six gross (2.2 net) wells that were drilled by other operators on our Utica Shale acreage and spud six gross and net wells and recompleted 29 gross and net wells on our Louisiana acreage. In addition, during the three months ended June 30, 2017, three gross (2.4 net) wells were spud in the SCOOP. We also participated in an additional 15 gross (0.5 net) wells that were drilled by other operators on our SCOOP acreage. Of these 37 new wells spud, at June 30, 2017, 27 were in various stages of completion and ten were being drilled. In addition, we turned-to-sales 31 gross (27.9 net) operated wells and 25 gross (4.2 net) non-operated wells in our Utica Shale and SCOOP operating areas, during the three months ended June 30, 2017.

- During the six months ended June 30, 2017, we reduced our unit lease operating expense by 8% to $0.23 per Mcfe from $0.25 per Mcfe during the six months ended June 30, 2016.

- During the six months ended June 30, 2017, we decreased our unit general and administrative expense by 20% to $0.15 per Mcfe from $0.18 per Mcfe during the six months ended June 30, 2016.

2017 Production and Drilling Activity

During the three months ended June 30, 2017, our total net production was 82,902,956 cubic feet, or Mcf, of natural gas, 650,021 barrels of oil and 53,807,975 gallons of NGLs for a total of 94,490 MMcfe, as compared to 52,775,359 Mcf of natural gas, 551,452 barrels of oil and 30,853,010 gallons of NGLs, or 60,492 MMcfe, for the three months ended June 30, 2016. Our total net production averaged approximately 1,038.4 MMcfe per day during the three months ended June 30, 2017 as compared to 664.7 MMcfe per day during the same period in 2016. The 56% increase in production is largely the result of the continuing development of our Utica Shale acreage and production attributable to the Acquisition.

Utica Shale. As of July 28, 2017, we held leasehold interests in approximately 232,000 gross (211,000 net) acres in the Utica Shale. From January 1, 2017 through July 28, 2017, we spud 63 gross (58.0 net) wells, of which 57 were in various stages of completion and six were being drilled at July 28, 2017. In addition, 12 gross (4.2 net) wells were drilled by other operators on our Utica Shale acreage during the six months ended June 30, 2017.

As of July 28, 2017, we had six horizontal rigs under contract on our Utica Shale acreage. We currently intend to spud 87 to 97 gross (67 to 74 net) wells, and commence sales from 72 to 80 gross (61 to 67 net) wells, on our Utica Shale acreage in 2017.

Aggregate net production from our Utica Shale acreage during the three months ended June 30, 2017 was approximately 78,003 MMcfe, or an average of 857.2 MMcfe per day, of which 93% was from natural gas and 7% was from oil and NGLs.

SCOOP. As of July 28, 2017, we held leasehold interests in approximately 49,200 net acres in the SCOOP. From January 1, 2017 through July 28, 2017, 12 gross (10.5 net) wells were spud, of which four were being drilled and eight were waiting on completion at July 28, 2017. In addition, 22 gross (0.8 net) wells were drilled by other operators on our SCOOP acreage during the period from February 17, 2017 to June 30, 2017.

As of July 28, 2017, we had six horizontal rigs under contract on our SCOOP acreage. We expect to return to four horizontal rigs in this play as contracts expire. We currently intend to spud 19 to 21 gross (16 to 18 net) wells, and commence sales from 17 to 19 gross (14 to 16 net) wells, on our SCOOP acreage in 2017.

Aggregate net production from our SCOOP acreage during the three months ended June 30, 2017 was approximately 14,744 MMcfe, or an average of 162.0 MMcfe per day, of which 69% was from natural gas and 31% was from oil and NGLs.

WCBB. From January 1, 2017 through July 28, 2017, we spud nine new wells and recompleted 54 wells. Aggregate net production from the WCBB field during the three months ended June 30, 2017 was approximately 1,254 MMcfe, or an average of 13.8 MMcfe per day, 100% of which was from oil.

East Hackberry Field. From January 1, 2017 through July 28, 2017, we spud five new wells and recompleted 17 wells. Aggregate net production from the East Hackberry field during the three months ended June 30, 2017 was approximately 369 MMcfe, or an average of 4.1 MMcfe per day, of which 98% was from oil and 2% was from natural gas.

West Hackberry Field. From January 1, 2017 through July 28, 2017, we did not spud any wells in our West Hackberry field. Aggregate net production from the West Hackberry field during the three months ended June 30, 2017 was approximately 26.9 MMcfe, or an average of 295.9 Mcfe per day, of which 100% was from oil.

Niobrara Formation. As of June 30, 2017, we held leases for approximately 4,000 net acres in the Niobrara Formation in Northwestern Colorado. From January 1, 2017 through July 28, 2017, there were no wells spud on our Niobrara Formation acreage. Aggregate net production was approximately 33.4 MMcfe, or an average of 366.8 Mcfe per day during the three months ended June 30, 2017, 76% of which was from oil.

Bakken. As of June 30, 2017, 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 June 30, 2017 was approximately 58.5 MMcfe, or an average of 642.7 Mcfe per day, of which 79% was from oil, 12% was from natural gas and 9% was from NGLs.

2017 Update Regarding Our Equity Investments

On June 5, 2017, we contributed all of our membership interests in Sturgeon (which owns Taylor Frac, LLC, Taylor Real Estate Investments, LLC and South River Road, LLC), Stingray Energy and Stingray Cementing to Mammoth Energy in exchange for approximately 2.0 million shares of Mammoth Energy common stock. As of June 30, 2017, we held approximately 25.1% of Mammoth Energy's outstanding common stock.

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 $3.1 billion at June 30, 2017 and $1.6 billion at December 31, 2016. 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. For instance, as a result of the decline in commodity prices in 2015 and 2016 and subsequent reduction in our proved reserves, we recognized a ceiling test impairment of $715.5 million for the year ended December 31, 2016. At June 30, 2017, the calculated ceiling was greater than the net book value of our oil and natural gas properties, thus no ceiling test impairment was required for the six months ended June 30, 2017. If prices of oil, natural gas and natural gas liquids decline in the future, 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 inflation of these costs, the productive life of the asset and our risk adjusted cost to settle such obligations discounted using our credit adjusted 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, 2016 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.

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 June 30, 2017, a valuation allowance of $556.9 million had been provided against the net deferred tax asset, with the exception of certain state net operating losses, or NOL, and alternative minimum tax, or AMT, credits that we expect to be able to utilize with NOL carrybacks and tax planning in the amount of $4.7 million.

Revenue Recognition. We derive almost all of our revenue from the sale of crude oil and natural gas produced from our oil and natural 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 three months ended March 31, 2016, we recognized an impairment loss related to our investment in Grizzly of approximately $23.1 million.

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 June 30, 2017.

RESULTS OF OPERATIONS

Comparison of the Three Months Ended June 30, 2017 and 2016

We reported net income of $105.9 million for the three months ended June 30, 2017 as compared to a net loss of $339.8 million for the three months ended June 30, 2016. This $445.7 million period-to-period increase was due primarily to a $352.1 million increase in natural gas, oil and NGL revenues and no impairment charge for the three months ended June 30, 2017 as compared to a $170.6 million impairment of oil and natural gas properties for the three months ended June 30, 2016, partially offset by a $19.6 million increase in midstream gathering and processing expenses, a $12.5 million increase in loss from equity method investments, net, an $8.1 million increase in interest expense and a $6.0 million increase in lease operating expenses for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016.

Oil and Gas Revenues. For the three months ended June 30, 2017, we reported natural gas, oil and NGL revenues of $324.0 million as compared to oil and natural gas revenues of negative $28.2 million during the same period in 2016. This $352.1 million, or 1,250%, increase in revenues was primarily attributable to the following:

- A $202.3 million increase in natural gas, oil and NGL sales due to a favorable change in gains and losses from derivative instruments. Of the total change, $258.6 million was due to favorable changes in the fair value of our open derivative positions in each period, offset by $56.3 million unfavorable change in settlements related to our derivative positions.

- A $129.6 million increase in natural gas sales without the impact of derivatives due to a 73% increase in natural gas market prices and a 57% increase in natural gas sales volumes.

- A $6.3 million increase in oil and condensate sales without the impact of derivatives due to an 8% increase in oil and condensate market prices and an 18% increase in oil and condensate sales volumes.
- A $13.9 million increase in natural gas liquids sales without the impact of derivatives due to a 35% increase in natural gas liquids market prices and a 74% increase in natural gas liquids sales volumes.

The following table summarizes our oil and natural gas production and related pricing for the three months ended June 30, 2017, as compared to such data for the three months ended June 30, 2016:

	Three months ended June 30, 2017		Three months ended June 30, 2016	
	($ In thousands)			
Natural gas sales				
Natural gas production volumes (MMcf)		82,903		52,775
Total natural gas sales	$	205,367	$	75,761
Natural gas sales without the impact of derivatives ($/Mcf)	$	2.48	$	1.44
Impact from settled derivatives ($/Mcf)	$	0.03	$	1.09
Average natural gas sales price, including settled derivatives ($/Mcf)	$	2.51	$	2.53
Oil and condensate sales				
Oil and condensate production volumes (MBbls)		650		551
Total oil and condensate sales	$	29,468	$	23,161
Oil and condensate sales without the impact of derivatives ($/Bbl)	$	45.33	$	42.00
Impact from settled derivatives ($/Bbl)	$	3.58	$	6.49
Average oil and condensate sales price, including settled derivatives ($/Bbl)	$	48.91	$	48.49
Natural gas liquids sales				
Natural gas liquids production volumes (MGal)		53,808		30,853
Total natural gas liquids sales	$	24,247	$	10,311
Natural gas liquids sales without the impact of derivatives ($/Gal)	$	0.45	$	0.33
Impact from settled derivatives ($/Gal)	$	—	$	—
Average natural gas liquids sales price, including settled derivatives ($/Gal)	$	0.45	$	0.33
Natural gas, oil and condensate and natural gas liquids sales				
Gas equivalents (MMcfe)		94,490		60,492
Total natural gas, oil and condensate and natural gas liquids sales	$	259,082	$	109,233
Natural gas, oil and condensate and natural gas liquids sales without the impact of derivatives ($/Mcfe)	$	2.74	$	1.81
Impact from settled derivatives ($/Mcfe)	$	0.05	$	1.01
Average natural gas, oil and condensate and natural gas liquids sales price, including settled derivatives ($/Mcfe)	$	2.79	$	2.82
Production Costs:				
Average production costs (per Mcfe)	$	0.22	$	0.24
Average production taxes and midstream costs (per Mcfe)	$	0.68	$	0.70
Total production and midstream costs and production taxes (per Mcfe)	$	0.90	$	0.94

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $20.7 million for the three months ended June 30, 2017 from $14.7 million for the three months ended June 30, 2016. This $6.0 million increase was primarily the result of an increase in expenses related to compression, location and facility repairs and maintenance, supervision and labor expenses, overhead and water hauling. However, due to increased efficiencies and a 56% increase in our production volumes for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016, our per unit LOE decreased by 10% from $0.24 per Mcfe to $0.22 per Mcfe.

Production Taxes. Production taxes increased $2.2 million to $5.1 million for the three months ended June 30, 2017 from $2.9 million for the three months ended June 30, 2016. This increase was related to an increase in realized prices and production volumes.

Midstream Gathering and Processing Expenses. Midstream gathering and processing expenses increased $19.6 million to $58.9 million for the three months ended June 30, 2017 from $39.3 million for the same period in 2016. This increase was primarily attributable to midstream expenses related to our increased production volumes in the Utica Shale resulting from our 2016 and 2017 drilling activities, as well as production volumes resulting from our recent SCOOP acquisition.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $82.2 million for the three months ended June 30, 2017, and consisted of $80.9 million in depletion of oil and natural gas properties and $1.3 million in depreciation of other property and equipment, as compared to total DD&A expense of $55.7 million for the three months ended June 30, 2016. This increase was due to an increase in our full cost pool as a result of our SCOOP acquisition and an increase in our production, partially offset by an increase in our total proved reserves volume used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $12.3 million for the three months ended June 30, 2017 from $11.9 million for the three months ended June 30, 2016. This $0.4 million increase was due to increases in salaries and benefits, consulting fees, legal fees and bank service charges, partially offset by a decrease in employee stock compensation expense and travel expenses. However, during the three months ended June 30, 2017, we decreased our unit general and administrative expense by 34% to $0.13 per Mcfe from $0.20 per Mcfe during the three months ended June 30, 2016.

Accretion Expense. Accretion expense remained relatively flat at $0.4 million and $0.3 million for the three months ended June 30, 2017 and 2016, respectively.

Interest Expense. Interest expense increased to $24.2 million for the three months ended June 30, 2017 from $16.1 million for the three months ended June 30, 2016 due primarily to the issuance of $600.0 million in aggregate principal amount of our 6.375% Senior Notes due 2025, or the 2025 Notes, in December 2016. In addition, total weighted average debt outstanding under our revolving credit facility was $142.0 million for the three months ended June 30, 2017 as compared to no debt outstanding under such facility for the same period in 2016. As of June 30, 2017, amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate of 3.46%. In addition, we capitalized approximately $3.6 million and $1.4 million in interest expense to undeveloped oil and natural gas properties during the three months ended June 30, 2017 and 2016, respectively. This increase in capitalized interest in the 2017 period was primarily due to the SCOOP Acquisition.

Income Taxes. As of June 30, 2017, we had a federal net operating loss carryforward of approximately $626.8 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 June 30, 2017, a valuation allowance of $556.9 million had been provided against the net deferred tax asset, with the exception of certain state NOLs and AMT credits that we expect to be able to utilize with NOL carrybacks and tax planning in the amount of $4.7 million.

Comparison of the Six Months Ended June 30, 2017 and 2016

We reported net income of $260.4 million for the six months ended June 30, 2017 as compared to a net loss of $582.0 million for the six months ended June 30, 2016. This $842.4 million period-to-period increase was due primarily to (a) a $528.2 million increase in natural gas, oil and NGL revenues, (b) no impairment charge for the six months ended June 30, 2017 as compared to a $389.6 million impairment of oil and natural gas properties for the six months ended June 30, 2016 and (c) a $13.4 million decrease in loss from equity method investments, net, partially offset by a $29.9 million increase in midstream gathering and processing expenses, a $15.6 million increase in interest expense and an $8.7 million increase in lease operating expenses for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016.

Oil and Gas Revenues. For the six months ended June 30, 2017, we reported oil and natural gas revenues of $657.0 million as compared to oil and natural gas revenues of $128.8 million during the same period in 2016. This $528.2 million, or 410%, increase in revenues was primarily attributable to the following:

- A $244.1 million increase in natural gas, oil and NGL sales due to a favorable change in gains and losses from derivative instruments. Of the total change, $373.0 million was due to favorable changes in the fair value of our open derivative positions in each period, offset by $128.9 million unfavorable change in settlements related to our derivative positions.

- A $233.3 million increase in natural gas sales without the impact of derivatives due to an 82% increase in natural gas market prices and a 41% increase in natural gas sales volumes.

- A $14.9 million increase in oil and condensate sales without the impact of derivatives due to a 37% increase in oil and condensate market prices and a 1% increase in oil and condensate sales volumes.

- A $35.8 million increase in natural gas liquid sales without the impact of derivatives due to a 100% increase in natural gas liquids market prices and a 41% increase in natural gas liquids sales volumes.

The following table summarizes our oil and natural gas production and related pricing for the six months ended June 30, 2017, as compared to such data for the six months ended June 30, 2016:

	Six months ended June 30, 2017	Six months ended June 30, 2016
	($ In thousands)	
Natural gas sales		
Natural gas production volumes (MMcf)	149,187	106,082
Total natural gas sales	$ 383,204	$ 149,855
Natural gas sales without the impact of derivatives ($/Mcf)	$ 2.57	$ 1.41
Impact from settled derivatives ($/Mcf)	$ (0.03)	$ 1.10
Average natural gas sales price, including settled derivatives ($/Mcf)	$ 2.54	$ 2.51
Oil and condensate sales		
Oil and condensate production volumes (MBbls)	1,164	1,153
Total oil and condensate sales	$ 53,879	$ 39,000
Oil and condensate sales without the impact of derivatives ($/Bbl)	$ 46.30	$ 33.82
Impact from settled derivatives ($/Bbl)	$ 2.07	$ 8.60
Average oil and condensate sales price, including settled derivatives ($/Bbl)	$ 48.37	$ 42.42
Natural gas liquids sales		
Natural gas liquids production volumes (MGal)	103,475	73,380
Total natural gas liquids sales	$ 55,426	$ 19,604
Natural gas liquids sales without the impact of derivatives ($/Gal)	$ 0.54	$ 0.27
Impact from settled derivatives ($/Gal)	$ —	$ —
Average natural gas liquids sales price, including settled derivatives ($/Gal)	$ 0.54	$ 0.27
Natural gas, oil and condensate and natural gas liquids sales		
Gas equivalents (MMcfe)	170,951	123,485
Total natural gas, oil and condensate and natural gas liquids sales	$ 492,509	$ 208,459
Natural gas, oil and condensate and natural gas liquids sales without the impact of derivatives ($/Mcfe)	$ 2.88	$ 1.69
Impact from settled derivatives ($/Mcfe)	$ (0.01)	$ 1.02
Average natural gas, oil and condensate and natural gas liquids sales price, including settled derivatives ($/Mcfe)	$ 2.87	$ 2.71
Production Costs:		
Average production costs (per Mcfe)	$ 0.23	$ 0.25
Average production taxes and midstream costs (per Mcfe)	$ 0.68	$ 0.67
Total production and midstream costs and production taxes (per Mcfe)	$ 0.91	$ 0.92

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $40.0 million for the six months ended June 30, 2017 from $31.3 million for the six months ended June 30, 2016. This increase was mainly the result of an increase in expenses related to supervision and labor, overhead, compressors, surface rentals, water hauling, workover costs and road, location and equipment repairs, partially offset by a decrease in ad valorem taxes and disposal costs. However, due to increased efficiencies and a 38% increase in our production volumes for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016, our per unit LOE decreased by 8% from $0.25 per Mcfe to $0.23 per Mcfe.

Production Taxes. Production taxes increased $3.0 million to $9.0 million for the six months ended June 30, 2017 from $6.0 million for the same period in 2016. This increase was primarily related to an increase in realized prices and production volumes.

Midstream Gathering and Processing Expenses. Midstream gathering and processing expenses increased by $29.9 million to $106.9 million for the six months ended June 30, 2017 from $77.0 million for the same period in 2016. This increase was primarily attributable to midstream expenses related to our increased production volumes in the Utica Shale resulting from our 2016 and 2017 drilling activities, as well as production volumes resulting from our recent SCOOP acquisition.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $148.2 million for the six months ended June 30, 2017, and consisted of $145.4 million in depletion of oil and natural gas properties and $2.8 million in depreciation of other property and equipment, as compared to total DD&A expense of $121.1 million for the six months ended June 30, 2016. This increase was due to an increase in our full cost pool as a result of our SCOOP acquisition and an increase in our production, partially offset by an increase in our total proved reserves volume used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $24.9 million for the six months ended June 30, 2017 from $22.5 million for the six months ended June 30, 2016. This $2.4 million increase was due to increases in salaries and benefits, consulting fees, bank service charges, computer support and franchise taxes, partially offset by a decrease in employee stock compensation expense. However, during the six months ended June 30, 2017, we decreased our unit general and administrative expense by 20% to $0.15 per Mcfe from $0.18 per Mcfe during the six months ended June 30, 2016.

Accretion Expense. Accretion expense was $0.7 million and $0.5 million for the six months ended June 30, 2017 and 2016, respectively.

Interest Expense. Interest expense increased to $47.7 million for the six months ended June 30, 2017 from $32.1 million for the six months ended June 30, 2016 due primarily to the issuance of $600.0 million of the 2025 Notes in December 2016. In addition, total weighted average debt outstanding under our revolving credit facility was $81.1 million for the six months ended June 30, 2017 as compared to no debt outstanding under such facility for the same period in 2016. Additionally, we capitalized approximately $6.7 million and $3.0 million in interest expense to undeveloped oil and natural gas properties during the six months ended June 30, 2017 and June 30, 2016, respectively. This increase in capitalized interest in the 2017 period was primarily due to the SCOOP Acquisition.

Income Taxes. As of June 30, 2017, we had a net operating loss carryforward of approximately $626.8 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 June 30, 2017, a valuation allowance of $556.9 million had been provided against the net deferred tax asset, with the exception of certain state NOLs and AMT credits that we expect to be able to utilize with NOL carrybacks and tax planning in the amount of $4.7 million.

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 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.

Net cash flow provided by operating activities was $286.7 million for the six months ended June 30, 2017 as compared to net cash flow provided by operating activities of $142.7 million for the same period in 2016. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 46% 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 six months ended June 30, 2017 was $1,644.6 million as compared to $281.0 million for the same period in 2016. During the six months ended June 30, 2017, we spent $460.8 million in additions to oil and natural gas properties, of which $274.6 million was spent on our 2017 drilling, completion and recompletion activities, $65.2 million was spent on expenses attributable to wells spud, completed and recompleted during 2016, $1.3 million was spent on facility enhancements, $53.8 million was spent on lease related costs, primarily the acquisition of leases in the Utica Shale and $7.2 million was spent on seismic, with the remainder attributable mainly to future location development and capitalized general and administrative expenses. We also spent $1.3 billion to fund the cash portion of the purchase price for our SCOOP acquisition. In addition, $1.2 million was invested in Grizzly and $23.0 million was invested in Strike Force during the six months ended June 30, 2017. We did not make any investments in our other equity investments during the six months ended June 30, 2017.

Net cash provided by financing activities for the six months ended June 30, 2017 was $199.7 million as compared to $421.8 million for the same period in 2016. The 2017 amount provided by financing activities is primarily attributable to borrowings under our revolving credit facility. The 2016 amount provided by financing activities is primarily attributable to the net proceeds of approximately $411.7 million from our March 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 December 13, 2021. As of June 30, 2017, we had a borrowing base of $1.0 billion and $210.0 million in borrowings outstanding, and total funds available for borrowing under our revolving credit facility, after giving effect to an aggregate of $237.5 million of outstanding letters of credit, were $552.5 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 1.00% to 2.00%, 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 2.00% to 3.00%, 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. As of June 30, 2017, amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate of 3.46%.

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 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 June 30, 2017.

***Senior Notes*.**

In October 2012, December 2012 and August 2014, we issued an aggregate of $600.0 million in principal amount of our 7.75% Senior Notes due 2020 which were issued under an indenture among us, our subsidiary guarantors and Wells Fargo Bank, National Association, as the trustee, and are referred to collectively as the 2020 Notes. In October 2016, we repurchased (in a cash tender offer) or redeemed all of the 2020 Notes, of which $600.0 million in aggregate principal amount was then outstanding, with the net proceeds from the issuance of our 6.000% Senior Notes due 2024, which are discussed below and are referred to herein as the 2024 Notes, and cash on hand, and the indenture governing the 2020 Notes was fully satisfied and discharged.

In April 2015, we issued an aggregate of $350.0 million in principal amount of our 6.625% Senior Notes due 2023 under a new indenture, dated as of April 21, 2015, among us, our subsidiary guarantors and Wells Fargo Bank, N.A., as trustee. 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 from April 21, 2015, payable semi-annually on May 1 and November 1 of each year, commencing on November 1, 2015. The 2023 Notes will mature on May 1, 2023.

On October 14, 2016, we issued the 2024 Notes in aggregate principal amount of $650.0 million. The 2024 Notes were issued under an indenture, dated as of October 14, 2016, among us, the subsidiary guarantors party thereto and the senior note indenture, 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. Under this 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. We received approximately $638.9 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.

On December 21, 2016, we issued $600.0 million in aggregate principal amount of 2025 Notes. The 2025 Notes were issued under an indenture, dated as of December 21, 2016, among us, the subsidiary guarantors party thereto and the senior note indenture, to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. Under this indenture, interest on the 2025 Notes accrues at a rate of 6.375% per annum on the outstanding principal amount thereof from December 21, 2016, payable semi-annually on May 15 and November 15 of each year, commencing on May 15, 2017. The 2025 Notes will mature on May 15, 2025. We received approximately $584.7 million in net proceeds from the offering of the 2025 Notes, which we used, together with the net proceeds from our December 2016 offering of common stock and cash on hand, to fund the cash portion of the purchase price for the SCOOP acquisition.

All of our existing and future restricted subsidiaries that guarantee our secured revolving credit facility or certain other debt guarantee the 2023 Notes, 2024 Notes and 2025 Notes, provided, however, that the 2023 Notes, 2024 Notes and 2025 Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of our future unrestricted subsidiaries. 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, 2024 Notes and 2025 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 amended and restated 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, 2024 Notes and 2025 Notes.

If we experience a change of control (as defined in the senior note indentures relating to the 2023 Notes, 2024 Notes and 2025 Notes), we will be required to make an offer to repurchase the 2023 Notes, 2024 Notes and 2025 Notes and 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 our senior note indentures, we will be required to use the remaining proceeds to make an offer to repurchase the 2023 Notes, 2024 Notes and 2025 Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase. The senior note indentures relating to the 2023 Notes, 2024 Notes and 2025 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. Under the indenture relating to the 2023 Notes, 2024 Notes and 2025 Notes, certain of these covenants are subject to termination upon the occurrence of certain events, including in the event the 2023 Notes, 2024 Notes and 2025 Notes are ranked as “investment grade.”

As required under the terms of the registration rights agreements relating to the 2024 Notes and the 2025 Notes, on July 7, 2017, we filed with the SEC a Registration Statement on Form S-4 relating to the exchange offers of the 2024 Notes and the 2025 Notes for substantially identical notes registered under the Securities Act. The Registration Statement was declared effective by the SEC on August 4, 2017. We commenced the Exchange Offers on August 8, 2017 and expect to close such Exchange Offers in September of 2017.

Construction Loan.

On June 4, 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, which was substantially completed in December 2016. The construction loan allows for maximum principal borrowings of $24.5 million and required us to fund 30% of the cost of the construction before any funds could 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 was 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 June 30, 2017, the total borrowings under the construction loan were approximately $24.0 million.

Capital Expenditures.

Our recent capital commitments have been primarily for the execution of our drilling programs, for acquisitions in the Utica Shale and our recent SCOOP acquisition, 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, 2016, 63.0% 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, 2017 through July 28, 2017, we spud 63 gross (58.0 net) wells in the Utica Shale. We currently expect to spud 87 to 97 gross (67 to 74 net) horizontal wells and commence sales from 72 to 80 gross (61 to 67 net) wells on our Utica Shale acreage during 2017. As of July 28, 2017, we had six operated horizontal rigs drilling in the play. We also anticipate an additional 30 to 34 gross (10 to 11 net) horizontal wells will be drilled, and sales commenced from 42 to 46 gross (nine to ten net) horizontal wells, on our Utica Shale acreage by other operators during 2017. We currently anticipate our 2017 capital expenditures to be $645.0 million to $690.0 million related to our operated and non-operated Utica Shale drilling and completion activity.

From January 1, 2017 through July 28, 2017, 12 gross (10.5 net) wells were spud in the SCOOP. We currently anticipate our 2017 capital expenditures to be $170.0 million to $190.0 million related to our operated and non-operated SCOOP drilling and completion activity. We currently expect to spud 19 to 21 gross (16 to 18 net) wells and commence sales from 17 to 19 gross (14 to 16 net) wells on the SCOOP acreage during 2017. As of July 28, 2017, we had six operated horizontal rigs drilling in the play, but expect to return to four horizontal rigs in this play as contracts expire. We also anticipate ten to 12 gross (one to two net) wells will be drilled, and sales commenced from ten to 12 gross (one to two net) wells on this SCOOP acreage by other operators during 2017.

In addition, we currently expect to spend an aggregate of $110.0 million to $120.0 million in 2017 for acreage expenses, primarily lease extensions, in the Utica Shale and SCOOP.

From January 1, 2017 through July 28, 2017, we spud nine new wells and recompleted 54 existing wells at our WCBB field. In our Hackberry fields, from January 1, 2017 through July 28, 2017, we spud five wells and recompleted 17 existing wells. We currently expect to spend $30.0 million to $35.0 million in 2017 to drill 12 to 15 gross and net wells and perform recompletion activities in Southern Louisiana.

From January 1, 2017 through July 28, 2017, no new wells were spud on our Niobrara Formation acreage. We do not currently anticipate any capital expenditures in the Niobrara Formation in 2017.

As of June 30, 2017, our net investment in Grizzly was approximately $51.6 million. We do not currently anticipate any material capital expenditures in 2017 related to Grizzly’s activities.

We had no capital expenditures during the six months ended June 30, 2017 related to our interests in Thailand. We do not currently anticipate any capital expenditures in Thailand in 2017.

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. See Note 3 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments. During the six months ended June 30, 2017, we paid $23.0 million in cash calls related to Strike Force. We currently anticipate that we will make $50.0 million to $60.0 million in cash contributions to Strike Force in 2017. We did not make any investments in any other of these entities during the six months ended June 30, 2017, and we do not currently anticipate any capital expenditures related to these entities in 2017.

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 85% of our currently anticipated Utica Shale drilling and completion costs for 2017. This has allowed us to secure a base level of activity for 2017, hedge against expected increases in service costs and ensure access to quality equipment and experienced crews, all of which we expect to contribute to further efficiency gains.

Our total capital expenditures for 2017 are currently estimated to be in the range of $845.0 million to $915.0 million for drilling and completion expenditures, of which $536.1 million was spent as of June 30, 2017. In addition, we currently expect to spend $110.0 million to $120.0 million in 2017 for acreage expenses, primarily lease extensions in the Utica Shale, of which $55.2 million was spent as of June 30, 2017, and $50.0 million to $60.0 million to fund our investment in Strike Force, of which $23.0 million was spent as of June 30, 2017. Approximately 75% and 20% of our 2017 estimated capital expenditures are currently expected to be spent in the Utica Shale and in the SCOOP play in Oklahoma, respectively. The 2017 range of capital expenditures is higher than the $549.5 million spent in 2016, primarily due to the increase in current commodity prices and our expansion into the SCOOP play in Oklahoma.

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 our Utica Basin and Mid-Continent operating areas, or to scale back our activity, as the market conditions warrant. Notwithstanding the foregoing, in the event commodity prices decline from current levels, 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 current low commodity price environment worsens, our revenues, cash flows, results of operations, liquidity and reserves may be materially and adversely affected.

Commodity Price Risk

See Item 3. “Quantitative and Qualitative Disclosures about Market Risk” for information regarding our open fixed price swaps at June 30, 2017.

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 can access the trust for use in plugging and abandonment charges associated with the property. As of June 30, 2017, the plugging and abandonment trust totaled approximately $3.1 million. At June 30, 2017, we have plugged 513 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our 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, 2016.

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of June 30, 2017.

New 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 we expect 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 evaluating the impact of this ASU on our consolidated financial statements and working to identify any potential differences that would result from applying the requirements of the ASU to existing contracts and current accounting policies and practices. This evaluation includes the review of contracts for each revenue stream identified within our business. We will conduct our contract review process throughout the remainder of 2017. Based on the continuing evaluation of our revenue streams, this ASU is not expected to have a material impact on our net income. We are still in the process of determining whether or not we will use the retrospective method or the modified retrospective approach to implementation and do not plan to early adopt this guidance.

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 and related disclosures; however, based on our current operating leases, it is not expected to have a material impact.

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. We adopted the standard as of January 1, 2017. There was no 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. 2016-09, *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. We adopted the standard as of January 1, 2017. We elected to recognize forfeitures of awards as they occur. The adoption of this standard did not have a material impact 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 June 2016, the FASB issued ASU No. 2016-13, *Financial Instruments-Credit Losses: Measurement of Credit Losses on Financial Instruments*. This ASU amends guidance on reporting credit losses for assets held at amortized cost basis and available for sale debt securities. For assets held at amortized cost basis, this ASU eliminates the probable initial recognition threshold in current GAAP and instead, requires an entity to reflect its current estimate of all expected credit losses. The amendments affect loans, debt securities, trade receivables, net investments in leases, off balance sheet credit exposure, reinsurance receivables and any other financial assets not excluded from the scope that have the contractual right to receive cash. We are currently evaluating the impact this standard will have on our financial statements and related disclosures and do not anticipate it to have a material affect.

In August 2016, the FASB issued ASU No. 2016-15, *Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments.* This ASU provides guidance of eight specific cash flow issues. This ASU 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.

In December 2016, the FASB issued ASU No. 2016-20, *Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers*. This guidance updates narrow aspects of the guidance issued in Update 2014-09. This amendment is effective for periods after December 15, 2017, with early adoption permitted. We in the process of evaluating the impact of this ASU on our consolidated financial statements.

In January 2017, the FASB issued ASU No. 2017-01, *Clarifying the Definition of a Business*. Under the current business combination guidance, there are three elements of a business: inputs, processes and outputs. The revised guidance adds an initial screen test to determine if substantially all of the fair value of the gross assets acquired is concentrated in a single asset or group of similar assets. If that screen is met, the set of assets is not a business. The new framework also specifies the minimum required inputs and processes necessary to be a business. 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 ASU 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 seven 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 July 28, 2017, the WTI posted price for crude oil was $49.71 per Bbl and the Henry Hub spot market price of natural gas was $2.92 per MMBtu. If the prices of oil and natural gas decline from current levels, 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 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 June 30, 2017:

	Location	Daily Volume (MMBtu/day)	Weighted Average Price	
Remaining 2017	NYMEX Henry Hub	681,000	$	3.20
2018	NYMEX Henry Hub	669,000	$	3.08
2019	NYMEX Henry Hub	57,000	$	3.10

	Location	Daily Volume (Bbls/day)	Weighted Average Price	
Remaining 2017	ARGUS LLS	2,000	$	53.12
Remaining 2017	NYMEX WTI	5,000	$	54.89
2018	NYMEX WTI	1,000	$	55.31

	Location	Daily Volume (Bbls/day)	Weighted Average Price	
Remaining 2017	Mont Belvieu C3	3,000	$	26.63
Remaining 2017	Mont Belvieu C5	250	$	49.14

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	
Remaining 2017	NYMEX Henry Hub	65,000	$	3.11
2018	NYMEX Henry Hub	103,000	$	3.25
2019	NYMEX Henry Hub	35,000	$	3.11

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 2018 through December 2018. The option to extend the terms expires in December 2017. If executed, we would have additional fixed price swaps for 30,000 MMBtu per day with the option to double at a weighted average price of $3.36 per MMBtu and additional short call options for 30,000 MMBtu per day with the option to double at a weighted average ceiling price of $3.36 per MMBtu.

In addition, we have entered into natural gas basis swap positions, which settle on the pricing index to basis differential of NGPL Mid-Continent to NYMEX Henry Hub natural gas price. As of June 30, 2017, we had the following natural gas basis swap positions for NGPL Mid-Continent.

	Location	Daily Volume (MMBtu/day)	Hedged Differential	
Remaining 2017	NGPL Mid-Continent	50,000	$	(0.26)
2018	NGPL Mid-Continent	12,000	$	(0.26)

Under our 2017 contracts, we have hedged approximately 62% to 64% of our estimated 2017 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 June 30, 2017, we had a net asset derivative position of $29.9 million as compared to a net liability derivative position of $19.9 million as of June 30, 2016, 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 $125.8 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $125.8 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. At June 30, 2017, we had $210.0 million in borrowings outstanding under our credit facility which bore interest at the eurodollar rate of 3.46%. A 1.0% increase in the average interest rate for the six months ended June 30, 2017 would have resulted in an estimated $0.4 million increase in interest expense. As of June 30, 2017, 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 Financial 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 Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

As of June 30, 2017, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and President and our Chief Financial 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 Financial Officer have concluded that, as of June 30, 2017, 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.

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. In March 2017, the United States Court of Appeals, Fifth Circuit issued its ruling. Subsequently, the Vermillion Parish case and Cameron Parish case have both had their respective stays lifted. On July 3, 2017, the Magistrate issued her Report and Recommendation on the Motion to Remand for the Vermillion Parish case, recommending that the plaintiffs' motion to remand be granted. On July 21, 2017, a group of the defendants in the Vermillion Parish case filed objections to the Magistrate's remand recommendation. No hearing on the remand motions has been set for the Cameron Parish case. 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 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 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, 2016.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

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).
4.8	Indenture, dated as of December 21, 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 6.375% Senior Notes due 2025) (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 21, 2016).
4.9	Registration Rights Agreement, dated as of December 21, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 21, 2016).

4.10	Registration Rights Agreement, dated as of February 17, 2017, by and between Gulfport Energy Corporation and Vitruvian II Woodford, LLC (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 24, 2017).
10.1	Eighth Amendment to Amended and Restated Credit Agreement, entered into as of March 29, 2017, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent and L/C issuer, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 4, 2017).
10.2	Ninth Amendment to Amended and Restated Credit Agreement, entered into as of May 4, 2017, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent and L/C issuer, the existing lenders named therein and JPMorgan Chase Bank, N.A., Commonwealth Bank of Australia, ABN, AMRO Capital USA LLC, Fifth Third Bank and Canadian Imperial Bank of Commerce, New York branch, as new lenders (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 9, 2017).
10.3	Employment Agreement, entered into as of April 28, 2017, effective as of January 1, 2017, by and between Gulfport Energy Corporation and Keri Crowell (incorporated by reference to Exhibit 10.3 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 9, 2017).
10.4	Employment Agreement, entered into as of April 28, 2017, effective as of January 1, 2017, by and between Gulfport Energy Corporation and Stuart Maier (incorporated by reference to Exhibit 10.4 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 9, 2017).
10.5	Employment Agreement, entered into as of April 28, 2017, effective as of January 1, 2017, by and between Gulfport Energy Corporation and Steve Baldwin (incorporated by reference to Exhibit 10.5 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 9, 2017).
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.

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: August 9, 2017

GULFPORT ENERGY CORPORATION

By: /s/ Keri Crowell

Keri Crowell
Chief Financial Officer

Exhibit 31.1

CERTIFICATION

I, Michael G. Moore, Chief Executive Officer of Gulfport Energy Corporation, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Gulfport Energy Corporation;

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

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

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

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

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

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

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

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

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

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

Date: August 9, 2017

/s/ Michael G. Moore
Michael G. Moore
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION

I, Keri Crowell, Chief Financial Officer of Gulfport Energy Corporation, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Gulfport Energy Corporation;

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

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

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

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

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

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

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

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

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

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

Date: August 9, 2017

/s/ Keri Crowell

Keri Crowell
Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF PERIODIC REPORT

I, Michael G. Moore, Chief Executive Officer of Gulfport Energy Corporation (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Quarterly Report on Form10-Q of the Company for the quarterly period ended June 30, 2017 (the "Report") fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: August 9, 2017

/s/ Michael G. Moore
Michael G. Moore
Chief Executive Officer and President

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION OF PERIODIC REPORT

I, Keri Crowell, Chief Financial Officer of Gulfport Energy Corporation (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Quarterly Report on Form 10-Q of the Company for the quarterly period ended June 30, 2017 (the "Report") fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: August 9, 2017

/s/ Keri Crowell
Keri Crowell
Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.