GULFPORT ENERGY CORP
Form 10-Q
May 09, 2018
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
ý QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2018 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)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ý 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 ý

As of May 1, 2018, 173,657,895 shares of the registrant's common stock were outstanding.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	March 31, 2018	December 31, 2017
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$118,613	$99,557
Accounts receivable—oil and natural gas	199,457	182,213
Prepaid expenses and other current assets	7,564	4,912
Short-term derivative instruments	50,906	78,847
Total current assets	376,540	365,529
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $2,971,119 and $2,912,974 excluded from amortization in 2018 and 2017, respectively	9,470,697	9,169,156
Other property and equipment	89,648	86,754
Accumulated depletion, depreciation, amortization and impairment	(4,264,647)	(4,153,733)
Property and equipment, net	5,295,698	5,102,177
Other assets:		
Equity investments	311,694	302,112
Long-term derivative instruments	15,769	8,685
Deferred tax asset	—	1,208
Inventories	8,505	8,227
Other assets	20,186	19,814
Total other assets	356,154	340,046
Total assets	$6,028,392	$5,807,752
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$577,548	$553,609
Asset retirement obligation—current	120	120
Short-term derivative instruments	37,570	32,534
Current maturities of long-term debt	629	622
Total current liabilities	615,867	586,885
Long-term derivative instruments	2,499	2,989
Asset retirement obligation—long-term	76,267	74,980
Deferred tax liability	2,884	—
Other non-current liabilities	2,963	2,963
Long-term debt, net of current maturities	2,239,023	2,038,321
Total liabilities	2,939,503	2,706,138
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:		
	1,735	1,831

Common stock - $.01 par value, 200,000,000 authorized, 173,523,487 issued and outstanding at March 31, 2018 and 183,105,910 at December 31, 2017		
Paid-in capital	4,319,034	4,416,250
Accumulated other comprehensive loss	(46,042)	(40,539)
Retained deficit	(1,185,838)	(1,275,928)
Total stockholders' equity	3,088,889	3,101,614
Total liabilities and stockholders' equity	$6,028,392	$5,807,752

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three months ended March 31,	
	2018	2017
	(In thousands, except share data)	
Revenues:		
Natural gas sales	$249,399	$ 177,837
Oil and condensate sales	45,686	24,411
Natural gas liquid sales	46,836	31,179
Net (loss) gain on natural gas, oil, and NGL derivatives	(16,529)	99,577
	325,392	333,004
Costs and expenses:		
Lease operating expenses	18,906	19,303
Production taxes	6,854	3,906
Midstream gathering and processing	64,193	47,941
Depreciation, depletion and amortization	111,018	65,991
General and administrative	13,099	12,600
Accretion expense	1,004	282
Acquisition expense	—	1,298
	215,074	151,321
INCOME FROM OPERATIONS	110,318	181,683
OTHER (INCOME) EXPENSE:		
Interest expense	33,965	23,479
Interest income	(37)	(842)
(Income) loss from equity method investments, net	(13,536)	4,907
Other income	(95)	(316)
	20,297	27,228
INCOME BEFORE INCOME TAXES	90,021	154,455
INCOME TAX BENEFIT	(69)	—
NET INCOME	$90,090	$ 154,455
NET INCOME PER COMMON SHARE:		
Basic	$0.50	$ 0.91
Diluted	$0.50	$ 0.91
Weighted average common shares outstanding—Basic	180,714,881	170,272,685
Weighted average common shares outstanding—Diluted	180,802,301	170,488,519

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three months ended March 31,	
	2018	2017
	(In thousands)	
Net income	$90,090	$154,455
Foreign currency translation adjustment	(5,503)	1,373
Other comprehensive (loss) income	(5,503)	1,373
Comprehensive income	$84,587	$155,828

See accompanying notes to consolidated financial statements.

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

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Accumulated Other Comprehensive Income (loss)	Retained Deficit	Total Stockholders' Equity
	(In thousands, except share data)					
Balance at January 1, 2018	183,105,910	$1,831	$4,416,250	$ (40,539)	$(1,275,928)	$3,101,614
Net income	—	—	—	—	90,090	90,090
Other Comprehensive Income	—	—	—	(5,503)	—	(5,503)
Stock-based Compensation	—	—	2,685	—	—	2,685
Shares Repurchased	(9,692,356)	(97)	(99,900)	—	—	(99,997)
Issuance of Restricted Stock	109,933	1	(1)	—	—	—
Balance at March 31, 2018	173,523,487	$1,735	$4,319,034	$ (46,042)	$(1,185,838)	$3,088,889
Balance at January 1, 2017	158,829,816	$1,588	$3,946,442	$ (53,058)	$(1,711,080)	$2,183,892
Net income	—	—	—	—	154,455	154,455
Other Comprehensive Income	—	—	—	1,373	—	1,373
Stock-based Compensation	—	—	2,553	—	—	2,553
Issuance of Common Stock for the Vitruvian Acquisition, net of related expenses	23,852,117	239	459,242	—	—	459,481
Issuance of Restricted Stock	153,868	1	(1)	—	—	—
Balance at March 31, 2017	182,835,801	$1,828	$4,408,236	$ (51,685)	$(1,556,625)	$2,801,754

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three months ended March 31, 2018	2017
	(In thousands)	
Cash flows from operating activities:		
Net income	$90,090	$154,455
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion	1,004	282
Depletion, depreciation and amortization	111,018	65,991
Stock-based compensation expense	1,611	1,532
(Gain) loss from equity investments	(13,495)	5,150
Change in fair value of derivative instruments	25,403	(106,796)
Deferred income tax benefit	(69)	—
Amortization of loan commitment fees	1,488	1,088
Changes in operating assets and liabilities:		
Increase in accounts receivable	(15,450)	(21,393)
Increase in accounts receivable—related party	—	(23)
Increase in prepaid expenses and other current assets	(2,652)	(8,366)
Decrease (increase) in other assets	14	(4,013)
Increase in accounts payable, accrued liabilities and other	27,486	54,738
Settlement of asset retirement obligation	(99)	—
Net cash provided by operating activities	226,349	142,645
Cash flows from investing activities:		
Additions to other property and equipment	(3,329)	(5,444)
Acquisition of oil and natural gas properties	—	(1,338,964)
Additions to oil and natural gas properties	(302,799)	(181,834)
Proceeds from sale of oil and natural gas properties	—	3,605
Proceeds from sale of other property and equipment	76	—
Contributions to equity method investments	(1,569)	(10,673)
Distributions from equity method investments	750	631
Net cash used in investing activities	(306,871)	(1,532,679)
Cash flows from financing activities:		
Principal payments on borrowings	(145)	—
Borrowings on line of credit	200,000	40,000
Borrowings on term loan	—	2,698
Debt issuance costs and loan commitment fees	(280)	(5,733)
Payments on repurchase of stock	(99,997)	—
Proceeds from issuance of common stock, net of offering costs	—	(5,321)
Net cash provided by financing activities	99,578	31,644
Net increase (decrease) in cash, cash equivalents and restricted cash	19,056	(1,358,390)
Cash, cash equivalents and restricted cash at beginning of period	99,557	1,460,875
Cash, cash equivalents and restricted cash at end of period	$118,613	$102,485
Supplemental disclosure of cash flow information:		
Interest payments	$7,944	$347
Income tax payments	$—	$—

Supplemental disclosure of non-cash transactions:		
Capitalized stock-based compensation	$1,074	$1,021
Asset retirement obligation capitalized	$382	$6,779
Interest capitalized	$843	$3,122
Foreign currency translation (loss) gain on equity method investments	$(5,503)	$1,373

See accompanying notes to consolidated financial statements.

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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 month period ended March 31, 2018 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 $1.3 million were incurred during the three months ended March 31, 2017 related to the Vitruvian Acquisition. No acquisition costs were incurred during the three months ended March 31, 2018.

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 by the Company in the Vitruvian Acquisition to acquire the properties and the fair value amount of the assets acquired as of February 17, 2017.

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	(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 period from the acquisition date of February 17, 2017 to March 31, 2017, the assets acquired in the Vitruvian Acquisition contributed $26.2 million of revenue to the Company’s consolidated statements of operations. The amount of net income contributed by the assets is impracticable to calculate due to the Company integrating the acquired assets into its overall operations using the full cost method of accounting.

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, 2017. 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, 2017; furthermore, the financial information is not intended to be a projection of future results.

	Three months ended March 31, 2017 (In thousands, except share data)
Pro forma revenue	$ 368,903
Pro forma net income	$ 175,881
Pro forma earnings per share (basic)	$ 1.03
Pro forma earnings per share (diluted)	$ 1.03

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2. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of March 31, 2018 and December 31, 2017 are as follows:

	March 31, 2018	December 31, 2017
	(In thousands)	
Oil and natural gas properties	$9,470,697	$9,169,156
Office furniture and fixtures	40,236	37,369
Building	44,592	44,565
Land	4,820	4,820
Total property and equipment	9,560,345	9,255,910
Accumulated depletion, depreciation, amortization and impairment	(4,264,647)	(4,153,733)
Property and equipment, net	$5,295,698	$5,102,177

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 March 31, 2018, 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 three months ended March 31, 2018. No impairment was required for oil and natural gas properties for the three months ended March 31, 2017.

Included in oil and natural gas properties at March 31, 2018 is the cumulative capitalization of $174.4 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 $8.8 million and $8.4 million for the three months ended March 31, 2018 and 2017, respectively.

The average depletion rate per Mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $0.93 and $0.84 per Mcfe for the three months ended March 31, 2018 and 2017, respectively.

The following table summarizes the Company's non-producing properties excluded from amortization by area at March 31, 2018:

	March 31, 2018
	(In thousands)
Utica	$1,548,121
MidContinent	1,421,853
Niobrara	449
Southern Louisiana	552
Bakken	99
Other	45
	$2,971,119

At December 31, 2017, approximately $2.9 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 in the Utica Shale have five-year extension terms which could extend this time frame beyond five years.

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A reconciliation of the Company’s asset retirement obligation for the three months ended March 31, 2018 and 2017 is as follows:

	March 31, 2018	March 31, 2017
	(In thousands)	
Asset retirement obligation, beginning of period	$75,100	$ 34,276
Liabilities incurred	329	6,779
Liabilities settled	(99)	—
Accretion expense	1,004	282
Revisions in estimated cash flows	53	—
Asset retirement obligation as of end of period	76,387	41,337
Less current portion	120	195
Asset retirement obligation, long-term	$76,267	$ 41,142

3. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of March 31, 2018 and December 31, 2017:

		Carrying value		(Income) loss from equity method investments	
	Approximate ownership %	March 31, 2018	December 31, 2017	Three months ended March 31, 2018	2017
		(In thousands)			
Investment in Tatex Thailand II, LLC	23.5 %	$—	$ —	$(41)	$(243)
Investment in Grizzly Oil Sands ULC	24.9999 %	53,564	57,641	330	365
Investment in Timber Wolf Terminals LLC	50.0 %	980	983	2	4
Investment in Windsor Midstream LLC	22.5 %	30	30	—	(311)
Investment in Stingray Cementing LLC[(1)]	— %	—	—	—	128
Investment in Blackhawk Midstream LLC	48.5 %	—	—	—	—
Investment in Stingray Energy Services LLC[(1)]	— %	—	—	—	197
Investment in Sturgeon Acquisitions LLC[(1)]	— %	—	—	—	68
Investment in Mammoth Energy Services, Inc.[(1)]	25.1 %	179,770	165,715	(13,470)	2,158
Investment in Strike Force Midstream LLC	25.0 %	77,350	77,743	(357)	2,541
		$311,694	$ 302,112	$(13,536)	$4,907

(1) On June 5, 2017, Mammoth Energy Services, Inc. ("Mammoth Energy") 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 March 31, 2018 and December 31, 2017.

Summarized balance sheet information:

	March 31, 2018	December 31, 2017
	(In thousands)	
Current assets	$395,679	$ 415,032
Noncurrent assets	$2,109,829	$ 1,542,090
Current liabilities	$285,521	$ 261,086
Noncurrent liabilities	$87,259	$ 148,839

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Summarized results of operations:

	Three months ended March 31,	
	2018	2017
	(In thousands)	
Gross revenue	$511,133	$94,478
Net income (loss)	$64,452	$(25,339)

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 an immaterial amount and $0.2 million in distributions from Tatex II during the three months ended March 31, 2018 and 2017, 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. In December 2017, Tatex III was dissolved and the Company received a final distribution of $0.2 million.

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 March 31, 2018, Grizzly had approximately 830,000 acres under lease in the Athabasca, Peace River and Cold Lake oil sands regions of Alberta, Canada. Grizzly has high-graded three oil sands projects to various stages of development. Grizzly commenced commercial production from its Algar Lake Phase I steam-assisted gravity drainage ("SAGD") oil sand project during the second quarter of 2014 and has regulatory approval for up to 11,300 barrels per day of bitumen production. Algar Lake production peaked at 2,200 barrels per day during the ramp-up phase of the SAGD facility, however, in April 2015, Grizzly made the decision to suspend operations at its Algar Lake facility due to the commodity price drop and its effect on project economics. Grizzly continues to monitor market conditions as it assesses start up plans for the facility. The Company reviewed its investment in Grizzly for impairment based on FASB ASC 323 at March 31, 2018 and 2017 and determined no impairment was required. If commodity prices decline in the future however, impairment of the investment in Grizzly may be necessary. During the three months ended March 31, 2018, Gulfport paid $1.6 million in cash calls. Grizzly’s functional currency is the Canadian dollar. The Company’s investment in Grizzly was decreased by $5.3 million as a result of a foreign currency translation loss and increased by $1.3 million as a result of a foreign currency translation gain for the three months ended March 31, 2018 and 2017, 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. During the three months ended March 31, 2018 and 2017, the Company paid no cash calls to Timber Wolf.

Windsor Midstream LLC

At March 31, 2018, 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. The Company received $0.2 million in distributions from Midstream during the three months ended March 31, 2017 and no distributions during the same period in 2018.

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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, the Company contributed all of its membership interests in Stingray Cementing to Mammoth Energy. 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, the Company contributed all of its membership interests in Stingray Energy to Mammoth 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, the Company contributed all of its membership interests in Sturgeon to Mammoth Energy. 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. 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. Following the contribution, Mammoth Energy completed its initial public offering of shares of its common stock.

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 (the "June 2017 Transactions"). As of March 31, 2018, 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 June 2017 Transactions at $18.50 per share, which was the closing price of Mammoth Energy common stock on June 5, 2017. During the second quarter of 2017, the Company recognized a gain of $12.5 million from the June 2017 Transactions. The Company’s investment in Mammoth Energy was decreased by a $0.2 million foreign currency loss and increased by a $0.1 million foreign currency gain resulting from Mammoth Energy’s foreign subsidiary for the three months ended March 31, 2018 and 2017, 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 through Strike Force Midstream LLC ("Strike Force"). In 2017, Rice was acquired by EQT Corporation ("EQT"). The Company owns a 25% interest in Strike

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Force, and EQT acts as operator and owns the remaining 75% interest in Strike Force. Construction of the gathering assets, which is ongoing, provides gathering services for wells operated by Gulfport and other operators and connectivity of existing dry gas gathering systems. During the three months ended March 31, 2018, Gulfport received distributions of $0.8 million from Strike Force. During the three months ended March 31, 2017, Gulfport paid $10.0 million in cash calls to Strike Force and received distributions of $0.4 million from Strike Force.

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 March 31, 2018, 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 VIE. 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 the completion of Mammoth Energy's IPO, the Company determined that it no longer held an interest in a VIE. 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 VIE.

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 March 31, 2018 and December 31, 2017:

	March 31, 2018	December 31, 2017
	(In thousands)	
Revolving credit agreement (1)	$200,000	$—
6.625% senior unsecured notes due 2023 (2)	350,000	350,000
6.000% senior unsecured notes due 2024 (3)	650,000	650,000
6.375% senior unsecured notes due 2025 (4)	600,000	600,000
6.375% senior unsecured notes due 2026 (5)	450,000	450,000
Net unamortized debt issuance costs (6)	(33,927)	(34,781)
Construction loan (7)	23,579	23,724
Less: current maturities of long term debt	(629)	(622)
Debt reflected as long term	$2,239,023	$2,038,321

The Company capitalized approximately $0.8 million and $3.1 million in interest expense to undeveloped oil and natural gas properties during the three months ended March 31, 2018 and 2017, respectively.

(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 December 31, 2021. 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. On November 21, 2017, the Company further amended its revolving credit facility to, among other things, (a) decrease the applicable rate for all loans by 0.5% and (b) add a provision that allows Gulfport to elect a commitment amount (the "Elected Commitment Amount") that is less than the borrowing base. In connection with this amendment, the borrowing base was set at $1.2 billion, with an elected commitment of $1.0 billion.

As of March 31, 2018, $200.0 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 $242.8 million of letters of credit, was $557.2 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 0.50% to 1.50%, plus (2) the highest of: (a) the federal funds rate plus 0.50%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its "prime rate," and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 1.50% to 2.50%, plus (2) the London interbank offered rate that appears on pages LIBOR01 or LIBOR02 of the Reuters screen that displays such rate for deposits in U.S. dollars, or, if such rate is not available, the rate as administered by ICE Benchmark Administration (or any other person that takes over administration of such rate) per annum equal to the offered rate on such other page or 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 March 31, 2018, amounts borrowed under the credit facility bore interest at the eurodollar rate with a weighted average of 3.52%.

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;
- 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 its financial covenants at March 31, 2018.

In connection with the Company's 2018 spring redetermination under the revolving credit facility, the lead lenders have proposed to increase the Company's borrowing base from $1.2 billion to $1.4 billion, with an elected commitment of $1.0 billion, and decrease the interest rate by 25 basis points, subject to the approval of the additional required banks within the syndicate.

(2) 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.

(3) 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 then 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.

(4) 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.

(5) On October 11, 2017, the Company issued $450.0 million in aggregate principal amount of its 6.375% Senior Notes due 2026 (the “2026 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. Interest on the 2026 Notes accrues at a rate of 6.375% per annum on the outstanding principal amount thereof from October 11, 2017, payable semi-annually on January 15 and July 15 of each year, commencing on January 15, 2018. The 2026 Notes will mature

on January 15, 2026. The Company received approximately $444.1 million in net proceeds from the offering of the 2026 Notes, a portion of which was used to repay all of the Company's outstanding borrowings under its secured revolving credit facility on October 11, 2017 and the balance was used to fund the remaining outspend related to the Company's 2017 capital development plans.

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In connection with the 2026 Notes offering, the Company and its subsidiary guarantors entered into a registration rights agreement pursuant to which the Company agreed to file a registration statement with respect to an offer to exchange the 2026 Notes for a new issue of substantially identical debt securities registered under the Securities Act. On January 18, 2018, the Company filed a registration statement on Form S-4 with respect to an offer to exchange the 2026 Notes for substantially identical debt securities registered under the Securities Act, which registration statement was declared effective by the SEC on February 12, 2018. The exchange offer relating to the 2026 notes closed on March 22, 2018.

(6) Loan issuance costs related to the 2023 Notes, the 2024 Notes, the 2025 Notes and the 2026 Notes (collectively the “Notes”) have been presented as a reduction to the Notes. At March 31, 2018, total unamortized debt issuance costs were $5.0 million for the 2023 Notes, $9.6 million for the 2024 Notes, $13.6 million for the 2025 Notes and $5.5 million for the 2026 Notes. In addition, loan commitment fee costs for the construction loan agreement described immediately below were $0.1 million at March 31, 2018.

(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. Starting June 30, 2017, the Company began making monthly payments of principal and interest, with the final payment due June 4, 2025. At March 31, 2018, the total borrowings under the Construction Loan were approximately $23.6 million.

6. COMMON STOCK AND CHANGES IN CAPITALIZATION

Issuance of Common Stock

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.

Stock Repurchase Program

In January 2018, the board of directors of the Company approved a stock repurchase program to acquire up to $100 million of the Company's outstanding stock during 2018. Purchases under the repurchase program may be made from time to time in open market or privately negotiated transactions, and are subject to market conditions, applicable legal requirements, contractual obligations, and other factors. The repurchase program does not require the Company to acquire any specific number of shares. This repurchase program is authorized to extend through December 31, 2018 and may be suspended from time to time, modified, extended, or discontinued by the board of directors at any time. During the three months ended March 31, 2018, the Company repurchased 9.7 million shares for a total cost of approximately $100.0 million. All repurchased shares have been retired.

7. STOCK-BASED COMPENSATION

During the three months ended March 31, 2018 and 2017, the Company’s stock-based compensation cost was $2.7 million and $2.6 million, respectively, of which the Company capitalized $1.1 million and $1.0 million, respectively, relating to its exploration and development efforts.

The following table summarizes restricted stock activity for the three months ended March 31, 2018:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of January 1, 2018	976,027	$ 18.71
Granted	140,041	8.77
Vested	(109,933)	21.42

Forfeited	(5,937)	17.34
Unvested shares as of March 31, 2018	1,000,198	$ 17.03

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Unrecognized compensation expense as of March 31, 2018 related to restricted shares was $12.9 million. The expense is expected to be recognized over a weighted average period of 1.53 years.

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8. EARNINGS PER SHARE

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

	Three months ended March 31,					
	2018			2017		
	Income	Shares	Per Share	Income	Shares	Per Share
	(In thousands, except share data)					
Basic:						
Net income	$90,090	180,714,881	$0.50	$154,455	170,272,685	$0.91
Effect of dilutive securities:						
Stock options and awards	—	87,420		—	215,834	
Diluted:						
Net income	$90,090	180,802,301	$0.50	$154,455	170,488,519	$0.91

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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 March 31, 2018, the plugging and abandonment trust totaled approximately $3.1 million. At March 31, 2018, the Company had plugged 551 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 March 31, 2018 were as follows:

	(In thousands)
Remaining 2018	$ 80
2019	54
Total	$ 134

Firm Transportation Commitments

The Company had approximately 2,621,000 MMBtu per day of firm sales contracted with third parties. The table below presents these commitments at March 31, 2018 as follows:

	(MMBtu per day)
Remaining 2018	552,000
2019	659,000
2020	526,000
2021	372,000
2022	272,000
Thereafter	240,000
Total	2,621,000

The Company also had approximately $3.7 billion of firm transportation contracted with third parties. The table below presents these commitments at March 31, 2018 as follows:

	(In thousands)
Remaining 2018	$186,036
2019	251,644
2020	247,581
2021	246,620
2022	246,620
Thereafter	2,511,853
Total	$3,690,354

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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 $0.9 million in non-utilization fees during the three months ended March 31, 2018. The Company did not incur any non-utilization fees during the three months ended March 31, 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 March 31, 2018 are $26.2 million.

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 and Lac Blanc oil and gas fields, 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 filed a motion to remand, and the plaintiffs agreed to an extension of time for all defendants to file responsive pleadings until the District Courts ruled on the motions to remand. In the Vermilion Parish case, the District Court entered an order on September 26, 2017 remanding the lawsuit to the 15th Judicial

District Court, State of Louisiana, Parish of Vermilion. In the Cameron Parish lawsuit, the federal magistrate, on January 18, 2018, issued a report and recommendation that the Cameron Parish lawsuit be remanded to the 38th Judicial District Court, State of Louisiana, Parish of Cameron. Due to the procedural posture of lawsuits and that responsive pleadings have not been filed, the parties have not begun discovery and the Company has not had the opportunity to evaluate the applicability of the allegations made in plaintiffs' complaints to the Company's operations, management cannot determine the amount of loss, if any, that may result.

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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 March 31, 2018.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
Remaining 2018	NYMEX Henry Hub	927,000	$ 3.02
2019	NYMEX Henry Hub	647,000	$ 2.84
2020	NYMEX Henry Hub	45,000	$ 2.77

	Location	Daily Volume (Bbls/day)	Weighted Average Price
Remaining 2018	ARGUS LLS	2,000	$ 56.22
2019	ARGUS LLS	1,000	$ 59.55
Remaining 2018	NYMEX WTI	4,000	$ 53.99
2019	NYMEX WTI	3,000	$ 57.62

	Location	Daily Volume (Bbls/day)	Weighted Average Price
Remaining 2018	Mont Belvieu C3	4,000	$ 28.97
2019	Mont Belvieu C3	1,000	$ 27.05
Remaining 2018	Mont Belvieu C5	500	$ 46.62

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
April 2018 - March 2019	NYMEX Henry Hub	50,000	$ 3.13
April 2019 - December 2019	NYMEX Henry Hub	30,000	$ 3.10

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For a portion of the natural gas fixed price swaps listed above, the counterparty has an option to extend the original terms an additional twelve months for the period January 2019 through December 2019. The option to extend the terms expires in December 2018. If executed, the Company would have additional fixed price swaps for 100,000 MMBtu per day at a weighted average price of $3.05 per MMBtu.

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 March 31, 2018 and December 31, 2017:

	March 31, 2018	December 31, 2017
	(In thousands)	
Short-term derivative instruments - asset	$50,906	$ 78,847
Long-term derivative instruments - asset	$15,769	$ 8,685
Short-term derivative instruments - liability	$37,570	$ 32,534
Long-term derivative instruments - liability	$2,499	$ 2,989

Gains and Losses

The following table presents the gain and loss recognized in Net (loss) gain on natural gas, oil and NGL derivatives in the accompanying consolidated statements of operations for the three months ended March 31, 2018 and 2017.

	Net (loss) gain on derivative instruments Three months ended March 31,	
	2018	2017
	(In thousands)	
Natural gas derivatives	$(9,696)	$86,277
Oil derivatives	(9,147)	10,905
Natural gas liquids derivatives	2,314	2,395
Total	$(16,529)	$99,577

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 March 31, 2018		
	Gross Assets (Liabilities) Presented in the Consolidated Balance Sheets	Gross Amounts Subject to Master Netting Agreements	Net Amount
	(In thousands)		
Derivative assets	$66,675	$ (27,431)	$39,244
Derivative liabilities	$(40,069)	$ 27,431	$(12,638)

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	As of December 31, 2017		
	Gross Assets (Liabilities) Presented in the Consolidated Balance Sheets	Gross Amounts Subject to Master Netting Agreements	Net Amount
	(In thousands)		
Derivative assets	$87,532	$ (22,199)	$65,333
Derivative liabilities	$(35,523)	$ 22,199	$(13,324)

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 March 31, 2018 and December 31, 2017:

	March 31, 2018		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			

Derivative Instruments	$ —	$66,675	$ —
Liabilities:			
Derivative Instruments	$ —	$40,069	$ —

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	December 31, 2017		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Derivative Instruments	$—	$87,532	$ —
Liabilities:			
Derivative Instruments	$—	$35,523	$ —

The Company estimates the fair value of all derivative instruments using industry-standard models that consider 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 three months ended March 31, 2018 were approximately $0.4 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.

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 March 31, 2018, the carrying value of the outstanding debt represented by the Notes was approximately $2.0 billion, including the unamortized debt issuance cost of approximately $5.0 million related to the 2023 Notes, approximately $9.6 million related to the 2024 Notes, approximately $13.6 million related to the 2025 Notes and approximately $5.5 million related to the 2026 Notes. Based on the quoted market price, the fair value of the Notes was determined to be approximately $2.0 billion at March 31, 2018.

13. REVENUE FROM CONTRACTS WITH CUSTOMERS

Revenue Recognition

On January 1, 2018, the Company adopted Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers ("ASC 606") using the modified retrospective transition applied to contracts that were not completed as of that date. Results for reporting periods beginning after January 1, 2018 are presented under ASC 606 while prior period amounts are not adjusted and continue to be reported in accordance with historic revenue recognition guidance. The Company’s revenues are primarily derived from the sale of natural gas, oil and condensate and natural gas liquids (“NGLs”). Sales of natural gas, oil and condensate and NGLs are recognized in the period that the performance obligations are satisfied. The Company generally considers the delivery of each unit (MMBtu or Bbl) to be separately identifiable and represents a distinct performance obligation that is satisfied at a point-in-time once control of the product has been transferred to the customer upon delivery to an agreed upon delivery point. The Company considers a variety of facts and circumstances in assessing the point of control transfer, including but not limited to: (i) whether the purchaser can direct the use of the product, (ii) the transfer of significant risks, (iii) the Company’s right to payment and (iv) transfer of legal title. Revenue is measured based on consideration specified in the contract with the customer, and excludes any amounts collected on behalf of third parties. These contracts typically include variable consideration that is based on pricing tied to market indices and volumes delivered in the current month. The payment date is usually within 30 days of the end of the calendar month in which the commodity is delivered.

The recognition of gains or losses on derivative instruments is outside the scope of ASC 606 and is not considered revenue from contracts with customers subject to ASC 606. The Company may use financial or physical contracts accounted for as derivatives as economic hedges to manage price risk associated with normal sales, or in limited cases may use them for contracts the Company intends to physically settle but do not meet all of the criteria to be treated as normal sales.

Taxes assessed by a governmental authority that are both imposed on and concurrent with a specific revenue-producing transaction, and that are collected by the Company from a customer, are excluded from revenue.

Transaction Price Allocated to Remaining Performance Obligations

A significant number of the Company's product sales are short-term in nature generally through evergreen contracts with contract terms of one year or less. These contracts typically automatically renew under the same provisions. For those contracts, the Company has utilized the practical expedient allowed in the new revenue accounting standard that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For product sales that have a contract term greater than one year, the Company has utilized the practical expedient that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required. Currently, the Company's product sales that have a contractual term greater than one year have no long-term fixed consideration.

Contract Balances

Receivables from contracts with customers are recorded when the right to consideration becomes unconditional, generally when control of the product has been transferred to the customer. Receivables from contracts with customers were $125.8 million and $135.0 million as of March 31, 2018 and December 31, 2017, respectively, and are reported in accounts receivable - oil and natural gas on the consolidated balance sheet. The Company currently has no assets or liabilities related to its revenue contracts, including no upfront or rights to deficiency payments.

Contract Modifications

For contracts modified prior to the beginning of the earliest reporting period presented under ASC 606, the Company has elected to reflect the aggregate of the effect of all modifications that occurred before the beginning of the earliest period presented under the new standard when identifying the satisfied and unsatisfied performance obligations, determining the transaction price and allocating the transaction price to the satisfied and unsatisfied performance obligations for the modified contracts at transition.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for certain gas and NGLs sales may be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production that was delivered to the purchaser and the price that will be received for the sale of the product. The differences between the estimates and the actual amounts for product sales is recorded in the month that payment is received from the purchaser. The Company has internal controls in place for the estimation process and any identified differences between revenue estimates and actual revenue received historically have not been significant. For the three months ended March 31, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

14. INCOME TAXES

On December 22, 2017, the President of the United States signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act, or the Tax Act, that significantly reformed the Internal Revenue Code of 1986, as amended. The Tax act substantially revised numerous areas of U.S. federal income tax law, including reducing the maximum corporate income tax rate from 35% to 21%, allowing for full expensing of certain capital expenditures, modifying the limitations on the utilization of net operating losses, and repealing the corporate alternative minimum tax. The various estimates included in determining the Company's tax provision as of December 31, 2017 remain provisional through the three months ended March 31, 2018 and may be adjusted through subsequent events such as the filing of its 2017 consolidated federal income tax return and the issuance of additional guidance from the Internal Revenue Service or from state tax authorities. There were no material changes to the provisional estimates during the quarter ended March 31, 2018.

15. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

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.

In connection with the 2024 Notes and the 2025 Notes Offerings, the Company and its subsidiary guarantors entered into two registration rights agreements, pursuant to which the Company agreed to file a registration statement with respect to offers to exchange the 2024 Notes and the 2025 Notes for new issues of substantially identical debt securities registered under the Securities Act. The exchange offers for the 2024 Notes and the 2025 Notes were completed on September 13, 2017.

On October 11, 2017, the Company issued $450.0 million in aggregate principal amount of the 2026 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. A portion of the net proceeds from the issuance of the 2026 Notes was used to repay all of the Company's outstanding borrowings under its secured revolving credit facility on October 11, 2017 and the balance was used to fund the remaining outspend related to the Company's 2017 capital development plans.

In connection with the 2026 Notes offering, the Company and its subsidiary guarantors entered into a registration rights agreement pursuant to which the Company agreed to file a registration statement with respect to an offer to exchange the 2026 Notes for a new issue of substantially identical debt securities registered under the Securities Act.

On January 18, 2018, the Company filed a registration statement on Form S-4 with respect to an offer to exchange the 2026 Notes for substantially identical debt securities registered under the Securities Act, which registration statement was declared effective by the SEC on February 12, 2018. The exchange offer relating to the 2026 notes closed on March 22, 2018.

The 2023 Notes, the 2024 Notes, the 2025 Notes and the 2026 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 2023 Notes, the 2024 Notes, the 2025 Notes and the 2026 Notes are not guaranteed by Grizzly Holdings,

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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 income (loss) 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.

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CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	March 31, 2018				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$81,357	$37,254	$ 2	$—	$118,613
Accounts receivable - oil and natural gas	133,387	66,070	—	—	199,457
Accounts receivable - intercompany	585,111	64,492	—	(649,603)	—
Prepaid expenses and other current assets	6,115	1,449	—	—	7,564
Short-term derivative instruments	50,906	—	—	—	50,906
Total current assets	856,876	169,265	2	(649,603)	376,540
Property and equipment:					
Oil and natural gas properties, full-cost accounting	6,769,164	2,702,262	—	(729)	9,470,697
Other property and equipment	89,597	51	—	—	89,648
Accumulated depletion, depreciation, amortization and impairment	(4,264,609)	(38)	—	—	(4,264,647)
Property and equipment, net	2,594,152	2,702,275	—	(729)	5,295,698
Other assets:					
Equity investments and investments in subsidiaries	2,458,237	77,350	53,563	(2,277,456)	311,694
Long-term derivative instruments	15,769	—	—	—	15,769
Deferred tax asset	—	—	—	—	—
Inventories	6,045	2,460	—	—	8,505
Other assets	13,569	6,617	—	—	20,186
Total other assets	2,493,620	86,427	53,563	(2,277,456)	356,154
Total assets	$5,944,648	$2,957,967	$ 53,565	$(2,927,788)	$6,028,392
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$443,963	$133,585	$ —	$—	$577,548
Accounts payable - intercompany	64,980	584,495	128	(649,603)	—
Asset retirement obligation - current	120	—	—	—	120
Short-term derivative instruments	37,570	—	—	—	37,570
Current maturities of long-term debt	629	—	—	—	629
Total current liabilities	547,262	718,080	128	(649,603)	615,867
Long-term derivative instruments	2,499	—	—	—	2,499
Asset retirement obligation - long-term	64,091	12,176	—	—	76,267
Deferred tax liability	2,884	—	—	—	2,884
Other non-current liabilities	—	2,963	—	—	2,963
Long-term debt, net of current maturities	2,239,023	—	—	—	2,239,023
Total liabilities	2,855,759	733,219	128	(649,603)	2,939,503
Stockholders' equity:					
Common stock	1,735	—	—	—	1,735
Paid-in capital	4,319,034	1,915,598	260,877	(2,176,475)	4,319,034

Accumulated other comprehensive (loss) income	(46,042)	—	(43,909)	43,909	(46,042)
Retained (deficit) earnings	(1,185,838)	309,150	(163,531)	(145,619)	(1,185,838)
Total stockholders' equity	3,088,889	2,224,748	53,437	(2,278,185)	3,088,889
Total liabilities and stockholders' equity	$5,944,648	$2,957,967	$ 53,565	$(2,927,788)	$6,028,392

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CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2017				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$67,908	$31,649	$ —	$—	$99,557
Accounts receivable - oil and natural gas	128,121	54,092	—	—	182,213
Accounts receivable - intercompany	554,439	63,374	—	(617,813)	—
Prepaid expenses and other current assets	4,719	193	—	—	4,912
Short-term derivative instruments	78,847	—	—	—	78,847
Total current assets	834,034	149,308	—	(617,813)	365,529
Property and equipment:					
Oil and natural gas properties, full-cost accounting,	6,562,147	2,607,738	—	(729)	9,169,156
Other property and equipment	86,711	43	—	—	86,754
Accumulated depletion, depreciation, amortization and impairment	(4,153,696)	(37)	—	—	(4,153,733)
Property and equipment, net	2,495,162	2,607,744	—	(729)	5,102,177
Other assets:					
Equity investments and investments in subsidiaries	2,361,575	77,744	57,641	(2,194,848)	302,112
Long-term derivative instruments	8,685	—	—	—	8,685
Deferred tax asset	1,208	—	—	—	1,208
Inventories	5,816	2,411	—	—	8,227
Other assets	12,483	7,331	—	—	19,814
Total other assets	2,389,767	87,486	57,641	(2,194,848)	340,046
Total assets	$5,718,963	$2,844,538	$ 57,641	$(2,813,390)	$5,807,752
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$416,249	$137,361	$ —	$(1)	$553,609
Accounts payable - intercompany	63,373	554,313	127	(617,813)	—
Asset retirement obligation - current	120	—	—	—	120
Short-term derivative instruments	32,534	—	—	—	32,534
Current maturities of long-term debt	622	—	—	—	622
Total current liabilities	512,898	691,674	127	(617,814)	586,885
Long-term derivative instruments	2,989	—	—	—	2,989
Asset retirement obligation - long-term	63,141	11,839	—	—	74,980
Other non-current liabilities	—	2,963	—	—	2,963
Long-term debt, net of current maturities	2,038,321	—	—	—	2,038,321
Total liabilities	2,617,349	706,476	127	(617,814)	2,706,138
Stockholders' equity:					
Common stock	1,831	—	—	—	1,831
Paid-in capital	4,416,250	1,915,598	259,307	(2,174,905)	4,416,250
	(40,539)	—	(38,593)	38,593	(40,539)

Accumulated other comprehensive (loss) income					
Retained (deficit) earnings	(1,275,928)	222,464	(163,200)	(59,264)	(1,275,928)
Total stockholders' equity	3,101,614	2,138,062	57,514	(2,195,576)	3,101,614
Total liabilities and stockholders' equity	$5,718,963	$2,844,538	$ 57,641	$(2,813,390)	$5,807,752

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three months ended March 31, 2018				
	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Total revenues	$213,561	$111,831	$ —	$—	$325,392
Costs and expenses:					
Lease operating expenses	13,831	5,075	—	—	18,906
Production taxes	4,011	2,843	—	—	6,854
Midstream gathering and processing	45,666	18,527	—	—	64,193
Depreciation, depletion and amortization	111,017	1	—	—	111,018
General and administrative	13,811	(713)	1	—	13,099
Accretion expense	790	214	—	—	1,004
Acquisition expense	—	—	—	—	—
	189,126	25,947	1	—	215,074
INCOME (LOSS) FROM OPERATIONS	24,435	85,884	(1)	—	110,318
OTHER (INCOME) EXPENSE:					
Interest expense	34,393	(428)	—	—	33,965
Interest income	(31)	(6)	—	—	(37)
(Income) loss from equity method investments and investments in subsidiaries	(99,864)	(357)	330	86,355	(13,536)
Other income	(84)	(11)	—	—	(95)
	(65,586)	(802)	330	86,355	20,297
INCOME (LOSS) BEFORE INCOME TAXES	90,021	86,686	(331)	(86,355)	90,021
INCOME TAX BENEFIT	(69)	—	—	—	(69)
NET INCOME (LOSS)	$90,090	$86,686	$ (331)	$ (86,355)	$ 90,090

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three months ended March 31, 2017				
	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Total revenues	$ 272,441	$ 60,563	$ —	$ —	$ 333,004
Costs and expenses:					
Lease operating expenses	17,449	1,854	—	—	19,303
Production taxes	3,102	804	—	—	3,906
Midstream gathering and processing	37,724	10,217	—	—	47,941
Depreciation, depletion and amortization	65,990	1	—	—	65,991
General and administrative	12,874	(275)	1	—	12,600
Accretion expense	282	—	—	—	282
Acquisition expense	—	1,298	—	—	1,298
	137,421	13,899	1	—	151,321
INCOME (LOSS) FROM OPERATIONS	135,020	46,664	(1)	—	181,683
OTHER (INCOME) EXPENSE:					
Interest expense	25,048	(1,569)	—	—	23,479
Interest income	(842)	—	—	—	(842)
(Income) loss from equity method investments and investments in subsidiaries	(42,614)	2,541	365	44,615	4,907
Other (income) expense	(1,027)	(189)	—	900	(316)
	(19,435)	783	365	45,515	27,228
INCOME (LOSS) BEFORE INCOME TAXES	154,455	45,881	(366)	(45,515)	154,455
INCOME TAX EXPENSE	—	—	—	—	—
NET INCOME (LOSS)	$ 154,455	$ 45,881	$ (366)	$ (45,515)	$ 154,455

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

	Three months ended March 31, 2018				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$90,090	$86,686	$(331)	$(86,355)	$90,090
Foreign currency translation adjustment	(5,503)	(187)	(5,316)	5,503	(5,503)
Other comprehensive (loss) income	(5,503)	(187)	(5,316)	5,503	(5,503)
Comprehensive income (loss)	$84,587	$86,499	$(5,647)	$(80,852)	$84,587

	Three months ended March 31, 2017				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$154,455	$45,881	$(366)	$(45,515)	$154,455
Foreign currency translation adjustment	1,373	55	1,318	(1,373)	1,373
Other comprehensive income (loss)	1,373	55	1,318	(1,373)	1,373
Comprehensive income (loss)	$155,828	$45,936	$952	$(46,888)	$155,828

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Three months ended March 31, 2018				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by operating activities	$144,895	$81,452	$1	$1	$226,349
Net cash (used in) provided by investing activities	(231,024)	(75,847)	(1,569)	1,569	(306,871)
Net cash provided by (used in) financing activities	99,578	—	1,570	(1,570)	99,578
Net increase in cash, cash equivalents and restricted cash	13,449	5,605	2	—	19,056
Cash, cash equivalents and restricted cash at beginning of period	67,908	31,649	—	—	99,557
Cash, cash equivalents and restricted cash at end of period	$81,357	$37,254	$2	$—	$118,613

	Three months ended March 31, 2017				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by operating activities	$139,260	$3,384	$1	$—	$142,645
Net cash (used in) provided by investing activities	(1,557,852)	(1,348,964)	(673)	1,374,810	(1,532,679)
Net cash provided by (used in) financing activities	31,644	1,374,137	673	(1,374,810)	31,644

Net (decrease) increase in cash, cash equivalents and restricted cash	(1,386,948)	28,557	1	—	(1,358,390)
Cash, cash equivalents and restricted cash at beginning of period	1,458,882	1,993	—	—	1,460,875
Cash, cash equivalents and restricted cash at end of period	$71,934	$ 30,550	$ 1	$ —	$ 102,485

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16. RECENT ACCOUNTING PRONOUNCEMENTS

In May 2014, the Financial Accounting Standards Board ("FASB") issued ASC 606. ASC 606 supersedes existing industry specific revenue recognition guidance and increases disclosure requirements. 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 Company adopted ASC 606 as of January 1, 2018 using the modified retrospective transition method applied to contracts that were not completed as of that date. Results for reporting periods beginning after January 1, 2018 are presented under the new revenue standard. Under the modified retrospective method, the Company recognizes the cumulative effect of initially applying the new revenue standard as an adjustment to the opening balance of retained earnings; however, no adjustment was required as a result of adopting the new revenue standard. The comparative information has not been restated and continues to be reported under the historic accounting standards in effect for those periods. The impact of the adoption of the new revenue standard is not expected to be material to the Company's net income on an ongoing basis.

In February 2016, the FASB issued ASU No. 2016-02, Leases. The standard updates the previous lease guidance by requiring the lessee to recognize a right-to-use asset and lease liability on the balance sheet for all leases with lease terms of more than 12 months. The accounting for lessors is largely unchanged. The guidance is effective for periods after December 15, 2018, with a modified retrospective approach to be used for implementation. The Company will not early adopt this standard, and will apply the revised lease rules for its interim and annual reporting periods starting January 1, 2019. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements and related disclosures by performing an impact assessment to analyze the population of arrangements that meet the definition of a lease under the new standard. This analysis could result in an impact to the Company's financial statements; however, that impact is currently not known.

Additionally, in January 2018, the FASB issued ASU No. 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842. The amendments in this update provide an optional transition to not evaluate existing or expired land easements that were not previously accounted for under current leases guidance in Topic 840. An entity that elects this practical expedient should evaluate new or modified land easements beginning at the date of adoption. An entity that does not elect this practical expedient should evaluate all existing or expired land easements in connection with the adoption of the new lease requirement in Topic 842 to assess whether they meet the definition of a lease. The Company is currently evaluating this guidance to determine whether or not to make use of this practical expedient.

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 guidance is effective for periods after December 15, 2019, with early adoption permitted. 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 effect.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments. This ASU clarifies how certain cash receipts and cash payments should be classified and presented in the statement of cash flows. The Company adopted this standard in the first quarter of 2018 and has made an accounting policy election to classify distributions received from equity method investees using the nature of the distribution approach, which classifies distributions received from investees as either cash inflows from operating activities or cash inflows from investing activities in the statement of cash flows based on the nature of the activities of the investee that generated the distribution. The impact of adopting this ASU was not material to prior periods presented.

In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash This ASU requires that amounts generally described as restricted cash and restricted cash equivalents be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period amounts shown on the statement of cash flows and to provide a reconciliation of the totals in the statement of cash flows to the related captions in the balance sheet when the cash, cash equivalents, restricted cash, and restricted cash equivalents are presented in more than one line item on the balance sheet. The Company adopted this standard in the first quarter of 2018 using the retrospective transition method. The adoption of this standard had no impact on the statement of cash flows for the three months ended March 31, 2018 and resulted in the addition of $185.0 million of restricted cash to the beginning cash balance and an increase to net cash used in investing activities by the same amount on the statement of cash flows for the three months ended March 31, 2017.

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. The Company adopted this standard in the first quarter of 2018 with no significant effect on its financial statements or related disclosures.

In February 2018, the FASB issued ASU No. 2018-02, Income statement - Reporting Comprehensive Income (Topic 220) - Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income, which allows a reclassification from accumulated other comprehensive income to retained earnings for standard tax effects resulting from the Tax Cuts and Jobs Act of 2017. The amendment will be effective for reporting periods beginning after December 15, 2018, and early adoption is permitted. The Company is currently assessing the impact of the ASU on its consolidated financial statements and related disclosures.

17. SUBSEQUENT EVENTS

Derivatives

In April 2018, the Company entered into fixed price swaps for 2018 for approximately 53,000 MMBtu of natural gas per day at a weighted average price of $2.84 per MMBtu. For 2019, the Company entered into fixed price swaps for approximately 15,000 MMBtu of natural gas per day at a weighted average price of $2.76 per MMBtu, for approximately 1,000 Bbls of oil per day at a weighted average price of $60.24 per Bbl, for approximately 2,000 Bbls of C3 propane per day at a weighted average price of $28.04 per Bbl and for approximately 500 Bbls of C5 pentane per day at a weighted average price of $54.08 per Bbl. For 2020, the Company entered into fixed price swaps for approximately 5,000 MMBtu of natural gas per day at a weighted average price of $2.76 per MMBtu. The Company’s fixed price swap contracts are tied to the commodity prices on NYMEX Henry Hub for natural gas, NYMEX WTI for oil, and Mont Belvieu for propane and pentane. 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 and oil or Mont Belvieu for propane and pentane.

Sale of Equity Interest in Strike Force Midstream LLC

On May 1, 2018, the Company sold its 25% equity interest in Strike Force to EQT Midstream Partners, LP for $175.0 million in cash.

Expanded Share Repurchase Program

In May 2018, Gulfport 's board of directors authorized the expansion of its stock repurchase program, authorizing the Company to acquire up to an additional $100 million of its outstanding common stock during 2018 for a total of up to $200 million. Purchases under the expanded repurchase program may be made from time to time in open market or privately negotiated transactions, and will be subject to market conditions, applicable legal requirements, contractual obligations and other factors. The repurchase program does not require the Company to acquire any specific number of shares. The Company intends to purchase shares under the repurchase program opportunistically with available funds while maintaining sufficient liquidity to fund its 2018 capital development program. This repurchase program is authorized to extend through December 31, 2018 and may be suspended from time to time, modified, extended or discontinued by the board of directors at any time.

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

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

Disclosure Regarding Forward-Looking Statements

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

Overview

We are an independent oil and natural gas exploration and production company focused on the exploration, exploitation, acquisition and production of natural gas, crude oil and natural gas liquids in the United States. Our corporate strategy is to internally identify prospects, acquire lands encompassing those prospects and evaluate those prospects using subsurface geology and geophysical data and exploratory drilling. Using this strategy, we have developed an oil and natural gas portfolio of proved reserves, as well as development and exploratory drilling opportunities on high potential conventional and unconventional oil and natural gas prospects. Our principal properties are located in the Utica Shale 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.

2018 Operational and Other Highlights

- Production increased 52% to 115,977 net million cubic feet of natural gas equivalent, or MMcfe, for the three months ended March 31, 2018 from 76,461 MMcfe for the three months ended March 31, 2017. Our net daily production for the first quarter of 2018 averaged 1,288.6 MMcfe per day and was comprised of approximately 88% natural gas, 8% natural gas liquids, or NGLs, and 4% oil.
- During the three months ended March 31, 2018, we spud 13 gross (10 net) wells in the Utica Shale, participated in an additional nine gross (1.8 net) wells that were drilled by other operators on our Utica Shale acreage and recompleted

19 gross and net wells on our Louisiana acreage. In addition, during the three months ended March 31, 2018, we spud five gross (3.8 net) wells in the SCOOP and participated in an additional 17 gross (2.6 net) wells that were drilled by other operators on our SCOOP acreage. Of the 18 new wells we spud, at March 31, 2018, 12 were in various stages of completion and six were being drilled. In addition, three gross and net operated wells and seven gross (3.1 net) non-

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operated wells were turned-to-sales in our Utica Shale operating area and seven gross (6.3 net) operated wells and 12 gross (0.4 net) non-operated wells were turned-to-sales in our SCOOP operating area during the three months ended March 31, 2018.

- During the three months ended March 31, 2018, we reduced our unit lease operating expense by 36% to $0.16 per Mcfe from $0.25 per Mcfe during the three months ended March 31, 2017.
- During the three months ended March 31, 2018, we decreased our unit general and administrative expense by 31% to $0.11 per Mcfe from $0.16 per Mcfe during the three months ended March 31, 2017.
- During the three months ended March 31, 2018, we decreased our unit midstream gathering and processing expense by 13% per Mcfe to $0.55 per Mcfe from $0.63 per Mcfe during the three months ended March 31, 2017.
- In January 2018, our board of directors approved a stock repurchase program to acquire up to $100.0 million of our outstanding common stock, and in May 2018 expanded this program to acquire up to an additional $100.0 million of our common stock, during 2018 for a total of up to $200.0 million, which we believe underscores the confidence we have in our business model, financial performance and asset base. During the three months ended March 31, 2018, we purchased 9,692,356 shares of our outstanding common stock for a total of approximately $100.0 million.
- On May 1, 2018, we sold our 25% equity interest in Strike Force Midstream LLC, or Strike Force, to EQT Midstream Partners, LP for $175.0 million in cash.

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2018 Production and Drilling Activity

During the three months ended March 31, 2018, our total net production was 102,041,668 cubic feet, or Mcf, of natural gas, 756,899 barrels of oil and 65,755,864 gallons of NGLs for a total of 115,977 MMcfe, as compared to 66,283,945 Mcf of natural gas, 513,654 barrels of oil and 49,667,157 gallons of NGLs, or 76,461 MMcfe, for the three months ended March 31, 2017. Our total net production averaged approximately 1,288.6 MMcfe per day during the three months ended March 31, 2018, as compared to 849.6 MMcfe per day during the same period in 2017. The 52% increase in production is largely the result of the continuing development of our Utica Shale acreage and the development of our SCOOP acreage.

Utica Shale. As of May 1, 2018, we held leasehold interests in approximately 240,000 gross (215,000 net) acres in the Utica Shale. From January 1, 2018 through May 1, 2018, we spud 14 gross (10.6 net) wells, of which 12 were in various stages of completion and two were being drilled at May 1, 2018. In addition, nine gross (1.8 net) wells were drilled by other operators on our Utica Shale acreage during the three months ended March 31, 2018.

As of May 1, 2018, we had two operated horizontal rigs under contract on our Utica Shale acreage. We currently intend to spud 36 to 40 gross (26 to 29 net) horizontal wells, and commence sales from 33 to 37 gross (33 to 37 net) wells, on our Utica Shale acreage in 2018.

Aggregate net production from our Utica Shale acreage during the three months ended March 31, 2018 was approximately 92,772 MMcfe, or an average of 1,030.8 MMcfe per day, of which 94% was from natural gas and 6% was from oil and NGLs.

SCOOP. As of May 1, 2018, we held leasehold interests in approximately 50,200 net surface acres in the SCOOP. From January 1, 2018 through May 1, 2018, we spud seven gross (5.8 net) wells, of which four were being drilled and three were waiting on completion at May 1, 2018. In addition, 17 gross (2.6 net) wells were drilled by other operators on our SCOOP acreage during the three months ended March 31, 2018.

As of May 1, 2018, we had four horizontal rigs under contract on our SCOOP acreage, but expect to release two of these rigs in mid-2018 as the contracts for these rigs expire. We currently intend to spud 15 to 16 gross (10 to 11 net) horizontal wells, and commence sales from 20 to 22 gross (16 to 18 net) wells, on our SCOOP acreage in 2018.

Aggregate net production from our SCOOP acreage during the three months ended March 31, 2018 was approximately 22,103 MMcfe, or an average of 245.6 MMcfe per day, of which 67% was from natural gas and 33% was from oil and NGLs.

WCBB. From January 1, 2018 through May 1, 2018, we did not spud any new wells and recompleted 22 wells. Aggregate net production from the WCBB field during the three months ended March 31, 2018 was approximately 844 MMcfe, or an average of 9.4 MMcfe per day, 100% of which was from oil.

East Hackberry Field. From January 1, 2018 through May 1, 2018, we did not spud any new wells and recompleted ten wells. Aggregate net production from the East Hackberry field during the three months ended March 31, 2018 was approximately 170 MMcfe, or an average of 1.9 MMcfe per day, of which 98% was from oil and 2% was from natural gas.

West Hackberry Field. From January 1, 2018 through May 1, 2018, we did not spud any wells in our West Hackberry field. Aggregate net production from the West Hackberry field during the three months ended March 31, 2018 was approximately 7.0 MMcfe, or an average of 77.9 Mcfe per day, all of which was from oil.

We currently intend to perform only recompletion activities on our acreage in Southern Louisiana in 2018.

Niobrara Formation. As of March 31, 2018, we held leases for approximately 3,000 net acres in the Niobrara Formation in Northwestern Colorado. From January 1, 2018 through May 1, 2018, there were no wells spud on our Niobrara Formation acreage. Aggregate net production was approximately 23.7 MMcfe, or an average of 262.9 Mcfe per day during the three months ended March 31, 2018, all of which was from oil.

Bakken. As of March 31, 2018, 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 March 31, 2018 was approximately 57.5 MMcfe, or an average of 638.9 Mcfe per day, of which 85% was from oil, 13% was from natural gas and 2% was from NGLs.

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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 $3.0 billion at March 31, 2018 and $2.9 billion at December 31, 2017. 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 March 31, 2018, 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 three months ended March 31, 2018. 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, 2017 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 March 31, 2018, a valuation allowance of $280.5 million had been provided against the net deferred tax asset.

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.

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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.

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 instrument depends on the intended use of the derivative and the resulting designation. 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 March 31, 2018.

RESULTS OF OPERATIONS

Comparison of the Three Months Ended March 31, 2018 and 2017

We reported net income of $90.1 million for the three months ended March 31, 2018 as compared to net income of $154.5 million for the three months ended March 31, 2017. This $64.4 million period-to-period decrease was due primarily to a $7.6 million decrease in natural gas, oil and NGL revenues, a $16.3 million increase in midstream gathering and processing expenses, a $10.5 million increase in interest expense and a $45.0 million increase in depreciation, depletion and amortization, partially offset by an $18.4 million increase in income from equity method investments for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017.

Oil and Gas Revenues. For the three months ended March 31, 2018, we reported natural gas, oil and NGL revenues of $325.4 million as compared to oil and natural gas revenues of $333.0 million during the same period in 2017. This $7.6 million, or 2%, decrease in revenues was primarily attributable to the following:

- A $116.1 million decrease in natural gas, oil and NGL sales due to an unfavorable change in gains and losses from derivative instruments. Of the total change, $132.2 million was due to unfavorable changes in the fair value of our open derivative positions in each period, partially offset by a $16.1 million favorable change in settlements related to our derivative positions.

- A $71.6 million increase in natural gas sales without the impact of derivatives due to a 54% increase in natural gas sales volumes, partially offset by a 9% decrease in natural gas market prices.

- A $21.3 million increase in oil and condensate sales without the impact of derivatives due to a 27% increase in oil and condensate market prices and a 47% increase in oil and condensate sales volumes.

- A $15.7 million increase in natural gas liquids sales without the impact of derivatives due to a 13% increase in natural gas liquids market prices and a 32% 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 March 31, 2018, as compared to such data for the three months ended March 31, 2017:

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	Three months ended March 31,	
	2018	2017
	($ In thousands)	
Natural gas sales		
Natural gas production volumes (MMcf)	102,042	66,284
Total natural gas sales	$249,399	$177,837
Natural gas sales without the impact of derivatives ($/Mcf)	$2.44	$2.68
Impact from settled derivatives ($/Mcf)	$0.16	$(0.11)
Average natural gas sales price, including settled derivatives ($/Mcf)	$2.60	$2.57
Oil and condensate sales		
Oil and condensate production volumes (MBbls)	757	514
Total oil and condensate sales	$45,686	$24,411
Oil and condensate sales without the impact of derivatives ($/Bbl)	$60.36	$47.52
Impact from settled derivatives ($/Bbl)	$(5.64)	$0.16
Average oil and condensate sales price, including settled derivatives ($/Bbl)	$54.72	$47.68
Natural gas liquids sales		
Natural gas liquids production volumes (MGal)	65,756	49,667
Total natural gas liquids sales	$46,836	$31,179
Natural gas liquids sales without the impact of derivatives ($/Gal)	$0.71	$0.63
Impact from settled derivatives ($/Gal)	$(0.04)	$—
Average natural gas liquids sales price, including settled derivatives ($/Gal)	$0.67	$0.63
Natural gas, oil and condensate and natural gas liquids sales		
Natural gas equivalents (MMcfe)	115,977	76,461
Total natural gas, oil and condensate and natural gas liquids sales	$341,921	$233,427
Natural gas, oil and condensate and natural gas liquids sales without the impact of derivatives ($/Mcfe)	$2.95	$3.05
Impact from settled derivatives ($/Mcfe)	$0.07	$(0.09)
Average natural gas, oil and condensate and natural gas liquids sales price, including settled derivatives ($/Mcfe)	$3.02	$2.96
Production Costs:		
Average production costs (per Mcfe)	$0.16	$0.25
Average production taxes and midstream costs (per Mcfe)	$0.61	$0.68
Total production and midstream costs and production taxes (per Mcfe)	$0.77	$0.93

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Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes decreased to $18.9 million for the three months ended March 31, 2018 from $19.3 million for the three months ended March 31, 2017. This $0.4 million decrease was primarily the result of a decrease in expenses related to location and facility repairs and maintenance and workover expense, partially offset by an increase in water hauling and overhead. In addition, due to increased efficiencies and a 52% increase in our production volumes for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017, our per unit LOE decreased by 36% from $0.25 per Mcfe to $0.16 per Mcfe.

Production Taxes. Production taxes increased $3.0 million to $6.9 million for the three months ended March 31, 2018 from $3.9 million for the three months ended March 31, 2017. This increase was related to an increase in production volumes and realized prices, as well as changes in our product mix and production location.

Midstream Gathering and Processing Expenses. Midstream gathering and processing expenses increased $16.3 million to $64.2 million for the three months ended March 31, 2018 from $47.9 million for the same period in 2017. This increase was primarily attributable to midstream expenses related to our increased production volumes in the Utica Shale resulting from our 2017 drilling activities, as well as production volumes resulting from our February 2017 SCOOP acquisition.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $111.0 million for the three months ended March 31, 2018, and consisted of $108.4 million in depletion of oil and natural gas properties and $2.6 million in depreciation of other property and equipment, as compared to total DD&A expense of $66.0 million for the three months ended March 31, 2017. This increase was due to an increase in our full cost pool 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 $13.1 million for the three months ended March 31, 2018 from $12.6 million for the three months ended March 31, 2017. This $0.5 million increase was due to increases in salaries and benefits, consulting fees and legal fees. However, during the three months ended March 31, 2018, we decreased our unit general and administrative expense by 31% to $0.11 per Mcfe from $0.16 per Mcfe during the three months ended March 31, 2017.

Accretion Expense. Accretion expense increased to $1.0 million for the three months ended March 31, 2018 from $0.3 million for the three months ended March 31, 2017, primarily due to changes in our asset retirement obligation assumptions in 2017.

Interest Expense. Interest expense increased to $34.0 million for the three months ended March 31, 2018 from $23.5 million for the three months ended March 31, 2017 due primarily to the issuance of $450.0 million in aggregate principal amount of our 6.375% Senior Notes due 2026, or the 2026 Notes, in October 2017. In addition, total weighted average debt outstanding under our revolving credit facility was $87.1 million for the three months ended March 31, 2018 as compared to $19.6 million debt outstanding under such facility for the same period in 2017. As of March 31, 2018, amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate which resulted in a weighted average rate of 3.52%. In addition, we capitalized approximately $0.8 million and $3.1 million in interest expense to undeveloped oil and natural gas properties during the three months ended March 31, 2018 and 2017, respectively. This decrease in capitalized interest in the 2018 period was primarily due to a decrease in our average undeveloped leasehold costs in the Utica, partially offset by the SCOOP acquisition.

Income Taxes. As of March 31, 2018, we had a federal net operating loss carryforward of approximately $574.4 million from prior years, 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 March 31, 2018, a valuation allowance of $280.5 million had been provided against the net deferred tax assets. On December 22, 2017, the President of the United States signed into law the Tax Cuts and Jobs Act. Further information on the tax impacts of the Tax Cut and Jobs Act is included in Note 14 of our consolidated financial statements.

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 $226.3 million for the three months ended March 31, 2018 as compared to net cash flow provided by operating activities of $142.6 million for the same period in 2017. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 55% 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 three months ended March 31, 2018 was $306.9 million as compared to $1.5 billion for the same period in 2017. During the three months ended March 31, 2018, we spent $302.8 million in additions to oil and natural gas properties, of which $71.3 million was spent on our 2018 drilling, completion and recompletion activities, $158.3 million was spent on expenses attributable to wells spud, completed and recompleted during 2017, $1.1 million was spent on facility enhancements, $46.4 million was spent on lease related costs, primarily the acquisition of leases in the Utica Shale, with the remainder attributable mainly to future location development and capitalized general and administrative expenses. In addition, we invested $1.6 million in Grizzly, and we received $0.8 million in distributions from our investment in Strike Force during the three months ended March 31, 2018. We did not make any investments in our other equity investments during the three months ended March 31, 2018. During the first quarter of 2017, we spent $1.3 billion to fund the cash portion of the purchase price for our SCOOP acquisition.

Net cash provided by financing activities for the three months ended March 31, 2018 was $99.6 million as compared to $31.6 million for the same period in 2017. The 2018 amount provided by financing activities is primarily attributable to borrowings under our revolving credit facility, partially offset by purchases under our stock repurchase program of approximately $100.0 million.

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 March 31, 2018, we had a borrowing base of $1.2 billion, with an elected commitment of $1.0 billion, and $200.0 million in borrowings outstanding. Total funds available for borrowing under our revolving credit facility, after giving effect to an aggregate of $242.8 million of outstanding letters of credit, were $557.2 million as of March 31, 2018. This facility is secured by substantially all of our assets. Our wholly-owned subsidiaries guarantee our obligations under our revolving credit facility.

Advances under our revolving credit facility may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 0.50% to 1.50%, plus (2) the highest of: (a) the federal funds rate plus 0.50%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its “prime rate,” and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 1.50% to 2.50%, plus (2) the London interbank offered rate that appears on pages LIBOR01 or LIBOR02 of the Reuters screen that displays such rate for deposits in U.S. dollars, or, if such rate is not available, the rate as administered by ICE Benchmark Administration (or any other person that takes over administration of such rate) per annum equal to the offered rate on such other page or other service that displays an average London interbank offered rate as administered by ICE Benchmark Administration (or any other person that takes over the administration of such rate) for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the “London Interbank Offered Rate” for deposits in U.S. dollars. As of March 31, 2018, amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate which resulted in a weighted average rate of 3.52%.

In connection with our spring 2018 redetermination under the revolving credit facility, the lead lenders have proposed to increase the borrowing base from $1.2 billion to $1.4 billion, with an elected commitment of $1.0 billion, and decrease the interest rate by 25 basis points, subject to the approval of the additional required banks within the syndicate.

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 March 31, 2018.

Senior Notes.

In April 2015, we issued an aggregate of $350.0 million in principal amount of our Senior Notes due 2023. Interest on these senior notes 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. 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. 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 our acquisition of certain assets from Vitruvian.

On October 11, 2017, we issued $450.0 million in aggregate principal amount of our 2026 Notes. Interest on the 2026 Notes accrues at a rate of 6.375% per annum on the outstanding principal amount thereof from October 11, 2017, payable semi-annually on January 15 and July 15 of each year, commencing on January 15, 2018. The 2026 Notes will mature on January 15, 2026. We received approximately $444.1 million in net proceeds from the offering of the 2026 Notes, a portion of which was used to repay all of our outstanding borrowings under our secured revolving credit facility on October 11, 2017 and the balance was used to fund the remaining outspend related to our 2017 capital development plans.

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, 2025 Notes and 2026 Notes, provided, however, that the 2023 Notes, 2024 Notes, 2025 Notes and 2026 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, 2025 Notes and 2026 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, 2025 Notes and 2026 Notes.

If we experience a change of control (as defined in the senior note indentures relating to the 2023 Notes, 2024 Notes, 2025 Notes and 2026 Notes), we will be required to make an offer to repurchase the 2023 Notes, 2024 Notes, 2025 Notes and 2026 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, 2025 Notes and 2026 Notes at a

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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, 2025 Notes and 2026 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, 2025 Notes and 2026 Notes, certain of these covenants are subject to termination upon the occurrence of certain events, including in the event the 2023 Notes, 2024 Notes, 2025 Notes and 2026 Notes are ranked as “investment grade.”
In connection with the issuance of the 2024 Notes, 2025 Notes and 2026 Notes, we and our subsidiary guarantors entered into registration rights agreements, pursuant to which we agreed to file a registration statement with respect to offers to exchange the 2024 Notes, 2025 Notes and 2026 Notes, as applicable, for new issues of substantially identical debt securities registered under the Securities Act. The exchange offers for the 2024 Notes and 2025 Notes were completed on September 13, 2017, and the exchange offer for the 2026 Notes was completed on March 22, 2018.
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, after which date we began making monthly payments of interest and principal. The final payment is due June 4, 2025. As of March 31, 2018, the total borrowings under the construction loan were approximately $23.6 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, 2017, 64.9% 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, 2018 through May 1, 2018, we spud 14 gross (10.6 net) wells in the Utica Shale. We currently expect to spud 36 to 40 gross (26 to 29 net) horizontal wells and commence sales from 33 to 37 gross (33 to 37 net) wells on our Utica Shale acreage during 2018. As of May 1, 2018, we had two operated horizontal rigs drilling in the play. We also anticipate an additional seven to eight net horizontal wells will be drilled, and sales commenced from nine to ten net horizontal wells, on our Utica Shale acreage by other operators during 2018. We currently anticipate our 2018 capital expenditures to be $425.0 million to $455.0 million related to our operated and non-operated Utica Shale drilling and completion activity.
From January 1, 2018 through May 1, 2018, seven gross (5.8 net) wells were spud in the SCOOP. We currently anticipate our 2018 capital expenditures to be $185.0 million to $210.0 million related to our operated and non-operated SCOOP drilling and completion activity. We currently expect to spud 15 to 16 gross (10 to 11 net) wells and commence sales from 20 to 22 gross (16 to 18 net) wells on the SCOOP acreage during 2018. As of May 1, 2018,

we had four operated horizontal rigs drilling in the play, but expect to release two of these rigs in mid-2018 as the contracts for these rigs expire. We also anticipate four to five net wells will be drilled, and sales commenced from two to three net wells on this SCOOP acreage by other operators during 2018.

From January 1, 2018 through May 1, 2018, we recompleted 22 existing wells and spud no new wells at our WCBB field. In our Hackberry fields, from January 1, 2018 through May 1, 2018, we recompleted ten existing wells and spud no new wells. We currently expect to spend approximately $20.0 million in 2018 to perform recompletion activities in Southern Louisiana.

From January 1, 2018 through May 1, 2018, no new wells were spud on our Niobrara Formation acreage. We do not currently anticipate any capital expenditures in the Niobrara Formation in 2018.

As of March 31, 2018, our net investment in Grizzly was approximately $53.6 million. We do not currently anticipate any material capital expenditures in 2018 related to Grizzly's activities.

We had no capital expenditures during the three months ended March 31, 2018 related to our interests in Thailand. We do not currently anticipate any capital expenditures in Thailand in 2018.

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 three months ended March 31, 2018, we received $0.8 million in distributions from Strike Force. We did not make any investments in any other of these entities during the three months ended March 31, 2018.

On May 1, 2018, we sold our 25% equity interest in Strike Force to EQT Midstream Partners, LP for $175.0 million in cash. As a result of this transaction, all future capital obligations associated with Strike Force were eliminated, including $20.0 million budgeted for the balance of 2018.

We now expect to spend an aggregate of approximately $120.0 million to $130.0 million for non-drilling and completion activities, which includes acreage expenses, primarily lease extensions in the Utica Shale, in 2018.

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. In 2017, an increase in commodity prices allowed us to increase our capital budget as compared to 2016 and the resulting 2017 development activities enabled us to reach a size and scale, both financially and operationally, where we can navigate the current commodity price environment and adjust our business model accordingly. In response to forward natural gas prices, we are focused on delivering growth within cash flow by exercising strict capital discipline and, as such, currently expect to reduce our planned capital expenditures by approximately 25% as compared to 2017.

Our total capital expenditures for 2018 are currently estimated to be in the range of $630.0 million to $685.0 million for drilling and completion expenditures, of which $247.9 million was spent as of March 31, 2018. Our 2018 capital expenditure budget is heavily weighted to the first half of 2018, and we currently estimate that approximately two-thirds of the 2018 capital budget will be invested during the first half of the year. In addition, we currently expect to spend approximately $120.0 million to $130.0 million in 2018 for non-drilling and completion expenditures, which includes acreage expenses, primarily lease extensions in the Utica Shale, of which $43.7 million was spent as of March 31, 2018. Approximately 67% and 30% of our 2018 estimated drilling and completion capital expenditures are currently expected to be spent in the Utica Shale and in the SCOOP, respectively. The 2018 range of capital expenditures is lower than the $1.2 billion spent in 2017, primarily due to the decrease in current commodity prices, specifically natural gas prices, and our desire to fund our capital development program within cash flow.

In January 2018, our board of directors approved a stock repurchase program to acquire up to $100.0 million of our outstanding common stock during 2018, which program we executed in full in the first quarter of 2018. We believe the repurchase of our outstanding common stock underscores the confidence we have in our business model, financial performance and asset base. Additionally, in May 2018, our board of directors authorized the expansion of the stock repurchase program, authorizing us to acquire up to an additional $100.0 million of our outstanding common stock during 2018 for a total of up to $200.0 million. Purchases under the expanded repurchase program may be made from time to time in open market or privately negotiated transactions, and will be subject to market conditions, applicable legal requirements, contractual obligations and other factors. The repurchase program does not require us to acquire any specific number of shares. We intend to purchase shares under the repurchase program opportunistically with available funds while maintaining sufficient liquidity to fund our 2018 capital development program. This repurchase program is authorized to extend through December 31, 2018 and may be suspended from time to time, modified, extended or discontinued by the board of directors at any time.

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 or decelerate our activity within the Utica Basin and SCOOP 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 March 31, 2018.

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 March 31, 2018, the plugging and abandonment trust totaled approximately $3.1 million. At March 31, 2018, we have plugged 551 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, 2017.

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of March 31, 2018.

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 ("ASC 606"). ASC 606 supersedes existing industry specific revenue recognition guidance and increases disclosure requirements. 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. We adopted ASC 606 as of January 1, 2018 using the modified retrospective transition method applied to contracts that were not completed as of that date. Results for reporting periods beginning after January 1, 2018 are presented under the new revenue standard. Under the modified retrospective method, we recognize the cumulative effect of initially applying the new revenue standard as an adjustment to the opening balance of retained earnings; however, no adjustment was required as a result of adopting the new revenue standard. The comparative information has not been restated and continues to be reported under the historic accounting standards in effect for those periods. The impact of the adoption of the new revenue standard is not expected to be material to our net income on an ongoing basis.

In February 2016, the FASB issued ASU No. 2016-02, Leases. The standard updates the previous lease guidance by requiring the lessee to recognize a right-to-use asset and lease liability on the balance sheet for all leases with lease terms of more than 12 months. The accounting for lessors is largely unchanged. The guidance is effective for periods after

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December 15, 2018, with a modified retrospective approach to be used for implementation. We will not early adopt this standard, and will apply the revised lease rules for our interim and annual reporting periods starting January 1, 2019. We are in the process of evaluating the impact of this guidance on our consolidated financial statements and related disclosures by performing an impact assessment to analyze the population of arrangements that meet the definition of a lease under the new standard. This analysis could result in an impact to our financial statements; however, that impact is currently not known.

Additionally, in January 2018, the FASB issued ASU No. 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842. The amendments in this update provide an optional transition to not evaluate existing or expired land easements that were not previously accounted for under current leases guidance in Topic 840. An entity that elects this practical expedient should evaluate new or modified land easements beginning at the date of adoption. An entity that does not elect this practical expedient should evaluate all existing or expired land easements in connection with the adoption of the new lease requirement in Topic 842 to assess whether they meet the definition of a lease. We are currently evaluating this guidance to determine whether or not to make use of this practical expedient.

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 effect.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments. This ASU clarifies how certain cash receipts and cash payments should be classified and presented in the statement of cash flows. We have made an accounting policy election to classify distributions received from equity method investees using the nature of the distribution approach, which classifies distributions received from investees as either cash inflows from operating activities or cash inflows from investing activities in the statement of cash flows based on the nature of the activities of the investee that generated the distribution. The impact of adopting this ASU was not material to prior periods presented.

In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash. This ASU requires that amounts generally described as restricted cash and restricted cash equivalents be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period amounts shown on the statement of cash flows and to provide a reconciliation of the totals in the statement of cash flows to the related captions in the balance sheet when the cash, cash equivalents, restricted cash, and restricted cash equivalents are presented in more than one line item on the balance sheet. We adopted this standard in the first quarter of 2018 using the retrospective transition method. The adoption of this standard had no impact on our statement of cash flows for the three months ended March 31, 2018 and resulted in the addition of $185.0 million of restricted cash to the beginning cash balance and an increase to net cash used in investing activities by the same amount on our statement of cash flows for the three months ended March 31, 2017.

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. We adopted this standard in the first quarter of 2018 with no significant effect on our financial statements or related disclosures.

In February 2018, the FASB issued ASU No. 2018-02, Income statement - Reporting Comprehensive Income (Topic 220) - Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income, which allows a reclassification from accumulated other comprehensive income to retained earnings for standard tax effects resulting from the Tax Cuts and Jobs Act of 2017. The amendment will be effective for reporting periods beginning after December 15, 2018, and early adoption is permitted. We are currently assessing the impact of the ASU on our consolidated financial statements and related disclosures.

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 2017, WTI prices ranged from $42.48 to $60.46 per barrel and the Henry Hub spot market price of natural gas ranged from $2.44 to $3.71 per MMBtu. On May 1, 2018, the WTI posted price for crude oil was $67.25 per Bbl and the Henry Hub spot market price of natural gas was $2.75 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 March 31, 2018:

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
Remaining 2018	NYMEX Henry Hub	927,000	$ 3.02
2019	NYMEX Henry Hub	647,000	$ 2.84
2020	NYMEX Henry Hub	45,000	$ 2.77

	Location	Daily Volume (Bbls/day)	Weighted Average Price
Remaining 2018	ARGUS LLS	2,000	$ 56.22
2019	ARGUS LLS	1,000	$ 59.55
Remaining 2018	NYMEX WTI	4,000	$ 53.99
2019	NYMEX WTI	3,000	$ 57.62

	Location	Daily Volume (Bbls/day)	Weighted Average Price
Remaining 2018	Mont Belvieu C3	4,000	$ 28.97
2019	Mont Belvieu C3	1,000	$ 27.05
Remaining 2018	Mont Belvieu C5	500	$ 46.62

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.

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	Location	Daily Volume (MMBtu/day)	Weighted Average Price
April 2018 - March 2019	NYMEX Henry Hub	50,000	$ 3.13
April 2019 - December 2019	NYMEX Henry Hub	30,000	$ 3.10

For a portion of the natural gas fixed price swaps listed above, the counterparty has an option to extend the original terms an additional twelve months for the period January 2019 through December 2019. The option to extend the terms expires in December 2018. If executed, we would have additional fixed price swaps for 100,000 MMBtu per day at a weighted average price of $3.05 per MMBtu.

Under our 2018 contracts, we have hedged approximately 76% to 77% of our estimated 2018 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 March 31, 2018, we had a net asset derivative position of $26.6 million as compared to a net liability derivative position of $30.0 million as of March 31, 2017, 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 $172.8 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $169.4 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 March 31, 2018, we had $200.0 million in borrowings outstanding under our credit facility which bore interest at the eurodollar rate of 3.52%. A 1.0% increase in the average interest rate for the three months ended March 31, 2018 would have resulted in an estimated $0.2 million increase in interest expense. As of March 31, 2018, 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 March 31, 2018, 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 March 31, 2018, 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.

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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 and Lac Blanc oil and gas fields, 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 filed a motion to remand, and the plaintiffs agreed to an extension of time for all defendants to file responsive pleadings until the District Courts ruled on the motions to remand. In the Vermilion Parish case, the District Court entered an order on September 26, 2017 remanding the lawsuit to the 15th Judicial District Court, State of Louisiana, Parish of Vermilion. In the Cameron Parish lawsuit, the federal magistrate, on January 18, 2018, issued a report and recommendation that the Cameron Parish lawsuit be remanded to the 38th Judicial District Court, State of Louisiana, Parish of Cameron. Due to the procedural posture of lawsuits, and the fact that responsive pleadings have not been filed, the parties have not begun discovery. We have not had the opportunity to evaluate the applicability of the allegations made in plaintiffs' complaints to our operations and 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, 2017.

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

Unregistered Sales of Equity Securities

None.

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Issuer Repurchases of Equity Securities

Our common stock repurchase activity for the three months ended March 31, 2018 was as follows:

Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs (1)	Approximate maximum dollar value of shares that may yet be purchased under the plans or programs (2)
January 1-31, 2018	—	$ —	—	$ 100,000,000
February 1-28, 2018	300,000	$ 9.96	300,000	$ 97,011,000
March 1-31, 2018	9,392,356	$ 10.33	9,392,356	$ 3,000
Total	9,692,356	$ 10.32	9,692,356	

(1) In January 2018, our board of directors approved a stock repurchase program to acquire up to $100.0 million of our outstanding common stock, and in May 2018 expanded this program authorizing us to acquire up to an additional $100.0 million of our outstanding common stock, during 2018 for a total of up to $200.0 million. The repurchase program does not require us to acquire any

(2) specific number of shares. This repurchase program is authorized to extend through December 31, 2018 and may be suspended from time to time, modified, extended or discontinued by our board of directors at any time. During the three months ended March 31, 2018, we repurchased and canceled approximately 9.7 million shares of our common stock at an average price of $10.32 for a total of $100.0 million.

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).

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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	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).
4.8	Indenture, dated as of October 11, 2017, 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 2026) (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 11, 2017).
4.9	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*	Employment Agreement, entered into and effective as of April 30, 2018, by and between Gulfport Energy Corporation and Michael G. Moore.
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.

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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: May 9, 2018

GULFPORT ENERGY
CORPORATION

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