GULFPORT ENERGY CORP
Form 10-Q
May 03, 2019
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
ýQUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2019 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)

Title of each class	Name of each exchange which registered	Ticker Symbol
Common stock, par value $0.01 per share	Nasdaq Global Select Market	GPOR

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 every Interactive Data File required to be submitted 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 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 April 29, 2019, 159,317,360 shares of the registrant’s common stock were outstanding.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	March 31, 2019	December 31, 2018
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$17,996	$52,297
Accounts receivable—oil and natural gas sales	144,996	210,200
Accounts receivable—joint interest and other	24,580	22,497
Prepaid expenses and other current assets	12,560	10,607
Short-term derivative instruments	17,958	21,352
Total current assets	218,090	316,953
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $2,877,001 and $2,873,037 excluded from amortization in 2019 and 2018, respectively	10,312,124	10,026,836
Other property and equipment	96,204	92,667
Accumulated depletion, depreciation, amortization and impairment	(4,757,814)	(4,640,098)
Property and equipment, net	5,650,514	5,479,405
Other assets:		
Equity investments	244,119	236,121
Inventories	11,018	4,754
Operating lease assets	29,795	—
Operating lease assets - related parties	58,659	—
Other assets	13,314	13,803
Total other assets	356,905	254,678
Total assets	$6,225,509	$6,051,036
Liabilities and Stockholders’ Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$568,184	$518,380
Short-term derivative instruments	25,921	20,401
Current portion of operating lease liabilities	27,983	—
Current portion of operating lease liabilities - related parties	20,618	—
Current maturities of long-term debt	656	651
Total current liabilities	643,362	539,432
Long-term derivative instruments	287	13,992
Asset retirement obligation—long-term	82,900	79,952
Deferred tax liability	3,127	3,127
Non-current operating lease liabilities	1,812	—
Non-current operating lease liabilities - related parties	38,041	—
Long-term debt, net of current maturities	2,087,714	2,086,765
Total liabilities	2,857,243	2,723,268
Commitments and contingencies (Note 8)		
Preferred stock, $.01 par value; 5,000,000 authorized, 30,000 authorized as redeemable 12% cumulative preferred stock, Series A; 0 issued and outstanding	—	—
Stockholders’ equity:		

Common stock - $.01 par value, 200,000,000 authorized, 159,421,965 issued and outstanding at March 31, 2019 and 162,986,045 at December 31, 2018	1,594	1,630
Paid-in capital	4,202,023	4,227,532
Accumulated other comprehensive loss	(52,225)	(56,026)
Accumulated deficit	(783,126)	(845,368)
Total stockholders’ equity	3,368,266	3,327,768
Total liabilities and stockholders’ equity	$6,225,509	$6,051,036

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three months ended March 31, 2019	2018
	(In thousands, except share data)	
Revenues:		
Natural gas sales	$276,016	$ 249,399
Oil and condensate sales	32,482	45,686
Natural gas liquid sales	32,125	46,836
Net loss on natural gas, oil, and NGL derivatives	(20,045)	(16,529)
	320,578	325,392
Costs and expenses:		
Lease operating expenses	19,807	18,906
Production taxes	7,921	6,854
Midstream gathering and processing expenses	70,282	64,193
Depreciation, depletion and amortization	118,433	111,018
General and administrative expenses	11,558	13,099
Accretion expense	1,067	1,004
	229,068	215,074
INCOME FROM OPERATIONS	91,510	110,318
OTHER (INCOME) EXPENSE:		
Interest expense	34,120	33,965
Interest income	(152)	(37)
Income from equity method investments, net	(4,273)	(13,536)
Other income	(427)	(95)
	29,268	20,297
INCOME BEFORE INCOME TAXES	62,242	90,021
INCOME TAX BENEFIT	—	(69)
NET INCOME	$62,242	$ 90,090
NET INCOME PER COMMON SHARE:		
Basic	$0.38	$ 0.50
Diluted	$0.38	$ 0.50
Weighted average common shares outstanding—Basic	162,823,997	180,714,881
Weighted average common shares outstanding—Diluted	163,099,409	180,802,301

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,	
	2019	2018
	(In thousands)	
Net income	$62,242	$90,090
Foreign currency translation adjustment	3,801	(5,503)
Other comprehensive income (loss)	3,801	(5,503)
Comprehensive income	$66,043	$84,587

See accompanying notes to consolidated financial statements.

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

	Common Stock		Paid-in Capital	Accumulated Other Comprehensive (Loss) Income	Accumulated Deficit	Total Stockholders' Equity
	Shares	Amount				
	(In thousands, except share data)					
Balance at January 1, 2019	162,986,045	$1,630	$4,227,532	$ (56,026)	$(845,368)	$3,327,768
Net Income	—	—	—	—	62,242	62,242
Other Comprehensive Income	—	—	—	3,801	—	3,801
Stock-based Compensation	—	—	2,785	—	—	2,785
Shares Repurchased	(3,618,634)	(37)	(28,293)	—	—	(28,330)
Issuance of Restricted Stock	54,554	1	(1)	—	—	—
Balance at March 31, 2019	159,421,965	$1,594	$4,202,023	$ (52,225)	$(783,126)	$3,368,266
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 Loss	—	—	—	(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

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three months ended March 31, 2019	2018
	(In thousands)	
Cash flows from operating activities:		
Net income	$62,242	$90,090
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion expense	1,067	1,004
Depletion, depreciation and amortization	118,433	111,018
Stock-based compensation expense	1,671	1,611
Income from equity investments	(4,132)	(13,495)
Change in fair value of derivative instruments	(4,791)	25,403
Deferred income tax benefit	—	(69)
Amortization of loan costs	1,585	1,488
Gain on sale of equity investments and other assets	(43)	—
Distributions from equity method investments	1,228	—
Changes in operating assets and liabilities:		
Decrease in accounts receivable—oil and natural gas sales	65,204	7,916
Increase in accounts receivable—joint interest and other	(2,083)	(23,366)
Increase in prepaid expenses and other current assets	(1,953)	(2,652)
Decrease in other assets	42	14
(Decrease) increase in accounts payable, accrued liabilities and other	(53,339)	27,486
Settlement of asset retirement obligation	(71)	(99)
Net cash provided by operating activities	185,060	226,349
Cash flows from investing activities:		
Additions to other property and equipment	(3,848)	(3,329)
Additions to oil and natural gas properties	(186,686)	(302,799)
Proceeds from sale of oil and natural gas properties	52	—
Proceeds from sale of other property and equipment	56	76
Contributions to equity method investments	(432)	(1,569)
Distributions from equity method investments	—	750
Net cash used in investing activities	(190,858)	(306,871)
Cash flows from financing activities:		
Principal payments on borrowings	(150,151)	(145)
Borrowings on line of credit	150,000	200,000
Debt issuance costs and loan commitment fees	(22)	(280)
Payments on repurchase of stock	(28,330)	(99,997)
Net cash (used in) provided by financing activities	(28,503)	99,578
Net (decrease) increase in cash, cash equivalents and restricted cash	(34,301)	19,056
Cash, cash equivalents and restricted cash at beginning of period	52,297	99,557
Cash, cash equivalents and restricted cash at end of period	$17,996	$118,613
Supplemental disclosure of cash flow information:		
Interest payments	$15,266	$7,944
Income tax receipts	$(1,794)	$—
Supplemental disclosure of non-cash transactions:		

Capitalized stock-based compensation	$1,114	$1,074
Asset retirement obligation capitalized	$1,952	$382
Interest capitalized	$766	$843
Foreign currency translation gain (loss) on equity method investments	$3,801	$(5,503)

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 ("GAAP") 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 months ended March 31, 2019 are not necessarily indicative of the results expected for the full year.

1. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of March 31, 2019 and December 31, 2018 are as follows:

	March 31, 2019	December 31, 2018
	(In thousands)	
Oil and natural gas properties	$10,312,124	$10,026,836
Office furniture and fixtures	46,118	42,581
Building	44,565	44,565
Land	5,521	5,521
Total property and equipment	10,408,328	10,119,503
Accumulated depletion, depreciation, amortization and impairment	(4,757,814)	(4,640,098)
Property and equipment, net	$5,650,514	$5,479,405

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, 2019, 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, 2019. No impairment was required for oil and natural gas properties for the three months ended March 31, 2018.

Included in oil and natural gas properties at March 31, 2019 is the cumulative capitalization of $211.0 million in general and administrative costs incurred and capitalized to the full cost pool. General and administrative costs capitalized to the full cost pool represent management’s estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized general and administrative costs were approximately $7.7 million and $8.8 million for the three months ended March 31, 2019 and 2018, 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 $1.02 and $0.93 per Mcfe for the three months ended March 31, 2019 and 2018, respectively.

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The following table summarizes the Company’s non-producing properties excluded from amortization by area at March 31, 2019:

	March 31, 2019
	(In thousands)
Utica	$1,493,746
MidContinent	1,382,118
Niobrara	451
Southern Louisiana	586
Bakken	100
	$2,877,001

At December 31, 2018, 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.

A reconciliation of the Company’s asset retirement obligation for the three months ended March 31, 2019 and 2018 is as follows:

	March 31, 2019	March 31, 2018
	(In thousands)	
Asset retirement obligation, beginning of period	$79,952	$75,100
Liabilities incurred	969	329
Liabilities settled	(71)	(99)
Accretion expense	1,067	1,004
Revisions in estimated cash flows	983	53
Asset retirement obligation as of end of period	82,900	76,387
Less current portion	—	120
Asset retirement obligation, long-term	$82,900	$76,267

2. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of March 31, 2019 and December 31, 2018:

		Carrying value		(Income) loss from equity method investments	
	Approximate ownership %	March 31, 2019	December 31, 2018	Three months ended March 31, 2019	2018
		(In thousands)			
Investment in Tatex Thailand II, LLC	23.5 %	$—	$ —	$(140)	$(41)
Investment in Grizzly Oil Sands ULC	24.9999 %	48,004	44,259	393	330
Investment in Timber Wolf Terminals LLC(1)	— %	—	—	—	2
Investment in Windsor Midstream LLC	22.5 %	39	39	—	—
Investment in Mammoth Energy Services, Inc.	21.9 %	196,076	191,823	(4,526)	(13,470)
Investment in Strike Force Midstream LLC(2)	— %	—	—	—	(357)

$244,119	$ 236,121	$(4,273)	$(13,536)

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(1) On June 5, 2018, the Company received its final distribution from Timber Wolf Terminals LLC ("Timber Wolf"). See below under Timber Wolf Terminals LLC for information regarding this distribution.

(2) On May 1, 2018, the Company sold its 25% interest in Strike Force Midstream LLC ("Strike Force") to EQT Midstream Partners, LP. See below under under Strike Force Midstream LLC for information regarding this transaction.

The tables below summarize financial information for the Company's equity investments as of March 31, 2019 and December 31, 2018.

Summarized balance sheet information:

	March 31, 2019	December 31, 2018

	(In thousands)	
Current assets	$516,169	$ 471,733
Noncurrent assets	$1,363,785	$ 1,302,488
Current liabilities	$188,896	$ 239,975
Noncurrent liabilities	$215,093	$ 94,575

Summarized results of operations:

	Three months ended March 31,	
	2019	2018
	(In thousands)	
Gross revenue	$264,844	$511,133
Net income	$24,756	$64,452

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 108,000 acres which includes the Phu Horm Field. The Company received $0.1 million and an immaterial amount in distributions from Tatex II during the three months ended March 31, 2019 and 2018, respectively.

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, 2019, Grizzly had approximately 830,000 acres under lease in the Athabasca, Peace River and Cold Lake oil sands regions of Alberta, Canada. The Company reviewed its investment in Grizzly for impairment at March 31, 2019 and 2018 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, 2019, Gulfport paid $0.4 million in cash calls. Grizzly’s functional currency is the Canadian dollar. The Company’s investment in Grizzly was increased by a $3.7 million foreign currency translation gain and decreased by a $5.3 million foreign currency translation loss for the three months ended March 31, 2019 and 2018, respectively.

Timber Wolf Terminals LLC

During 2012, the Company invested in 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, the Company paid no cash calls to Timber Wolf. Timber Wolf was dissolved in 2018.

Windsor Midstream LLC

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At March 31, 2019, the Company held a 22.5% interest in Windsor Midstream LLC (“Midstream”), an entity controlled and managed by an unrelated third party. The Company received no distributions from Midstream during the three months ended March 31, 2019 and 2018.

Mammoth Energy Services, Inc.

At March 31, 2019, the Company owned 9,831,770 shares, or approximately 21.9%, of the outstanding common stock of Mammoth Energy Services, Inc. ("Mammoth Energy"). The Company’s investment in Mammoth Energy was increased by a $0.1 million foreign currency translation gain and decreased by a $0.2 million foreign currency translation loss resulting from Mammoth Energy’s foreign subsidiary for the three months ended March 31, 2019 and 2018, respectively. During the three months ended March 31, 2019, Gulfport received distributions of $1.2 million from Mammoth Energy as a result of a $0.125 per share dividend in February 2019. The approximate fair value of the Company's investment in Mammoth Energy's common stock at March 31, 2019 was $163.7 million based on the quoted market price of Mammoth Energy's common stock. 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”), then a subsidiary of Rice Energy Inc., to develop natural gas gathering assets in eastern Belmont County and Monroe County, Ohio through Strike Force. In 2017, Rice was acquired by EQT Corporation ("EQT"). The Company owned a 25% interest in Strike Force, which was sold to EQT Midstream Partners, LP in May 2018. The (income) loss from equity method investments presented in the table above reflects any intercompany profit eliminations. During the three months ended March 31, 2018, Gulfport received distributions of $0.8 million from Strike Force.

3. VARIABLE INTEREST ENTITIES

As of March 31, 2019, the Company held a variable interest in Midstream, a variable interest entity ("VIE"), but was not the primary beneficiary. This entity has governing provisions that are the functional equivalent of a limited partnership and is considered a VIE 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 this VIE 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 VIE's economic performance.

The Company accounts for its investment in 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 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 2 for further discussion of this entity, including the carrying amount of the investment.

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4. LONG-TERM DEBT

Long-term debt consisted of the following items as of March 31, 2019 and December 31, 2018:

	March 31, 2019	December 31, 2018
	(In thousands)	
Revolving credit agreement (1)	$45,000	$45,000
6.625% senior unsecured notes due 2023	350,000	350,000
6.000% senior unsecured notes due 2024	650,000	650,000
6.375% senior unsecured notes due 2025	600,000	600,000
6.375% senior unsecured notes due 2026	450,000	450,000
Net unamortized debt issuance costs (2)	(29,628)	(30,733)
Construction loan	22,998	23,149
Less: current maturities of long term debt	(656)	(651)
Debt reflected as long term	$2,087,714	$2,086,765

The Company capitalized approximately $0.8 million in interest expense to undeveloped oil and natural gas properties during each of the three months ended March 31, 2019 and 2018.

(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.

As of March 31, 2019, $45.0 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 $271.1 million of letters of credit, was $683.9 million. The Company’s wholly-owned subsidiaries have guaranteed the obligations of the Company under the revolving credit facility.

At March 31, 2019, amounts borrowed under the revolving credit facility bore interest at a weighted average rate of 3.99%.

The Company was in compliance with its financial covenants under the revolving credit facility at March 31, 2019.

(2) Loan issuance costs related to the 6.625% Senior Notes due 2023 (the "2023 Notes"), the 6.000% Senior Notes due 2024 (the "2024 Notes"), the 6.375% Senior Notes due 2025 (the "2025 Notes") and the 6.375% Senior Notes due 2026 (the "2026 Notes") (collectively the “Notes”) have been presented as a reduction to the Notes. At March 31, 2019, total unamortized debt issuance costs were $4.2 million for the 2023 Notes, $8.4 million for the 2024 Notes, $12.1 million for the 2025 Notes and $4.9 million for the 2026 Notes. In addition, loan commitment fee costs for the Company's construction loan agreement were $0.1 million at March 31, 2019.

5. COMMON STOCK AND CHANGES IN CAPITALIZATION

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. In May 2018, the Company'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. The repurchase program did not require the Company to acquire any specific number of shares. This repurchase program was authorized to extend through December 31, 2018 and was fully executed.

In January 2019, the board of directors of the Company approved a new stock repurchase program to acquire up to $400 million of the Company's outstanding common stock within a 24 month period. 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, 2020 and may be suspended from time to time, modified, extended or discontinued by the board of directors at any time. The Company repurchased 3.6 million shares for a cost of approximately $28.2 million during the three months ended March 31, 2019. Additionally, during the three months ended March 31, 2019, the Company repurchased an immaterial number of shares for a

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cost of approximately $0.1 million to satisfy tax withholding requirements incurred upon the vesting of restricted stock. All repurchased shares have been canceled and returned to the status of authorized but unissued shares.

6. STOCK-BASED COMPENSATION

The Company has granted restricted stock units to employees and directors pursuant to the 2013 Restated Incentive Stock Plan ("2013 Plan") as discussed below. During the three months ended March 31, 2019 and 2018, the Company’s stock-based compensation expense, which is included in general and administrative expenses in the accompanying consolidated statement of operations, was $2.8 million and $2.7 million, respectively, of which the Company capitalized $1.1 million during both the three months ended March 31, 2019 and 2018, relating to its exploration and development efforts.

The following table summarizes restricted stock unit activity for the three months ended March 31, 2019:

	Number of Unvested Restricted Stock Units	Weighted Average Grant Date Fair Value	Number of Unvested Performance Vesting Restricted Stock Units	Weighted Average Grant Date Fair Value
Unvested shares as of January 1, 2019	1,535,811	$ 11.57	$ —	$ —
Granted	470,603	7.97	228,659	9.66
Vested	(54,554)	10.63	—	—
Forfeited	(5,119)	12.61	—	—
Unvested shares as of March 31, 2019	1,946,741	$ 10.73	228,659	$ 9.66

Restricted Stock Units

Restricted stock units awarded under the 2013 Plan generally vest over a period of one year in the case of directors and three years in the case of employees and vesting is dependent upon the recipient meeting applicable service requirements. Stock-based compensation expense is expensed ratably over the service period. The grant date fair value of restricted stock units represents the closing market price of the Company's common stock on the date of grant. Unrecognized compensation expense as of March 31, 2019 related to restricted stock units was $14.8 million. The expense is expected to be recognized over a weighted average period of 2.09 years.

Performance Vesting Restricted Stock Units

During the three months ended March 31, 2019, the Company awarded performance vesting units to its Chief Executive Officer under the 2013 Plan. The number of shares of common stock that will ultimately be issued will be determined by comparing the Company's total stockholder return relative to the total stockholder return of a predetermined group of peer companies at the end of the performance period. The performance period is 36 months. The grant date fair value was determined using the Monte Carlo simulation method and is being expensed ratably over the performance period. Expected volatilities utilized in the model were estimated using a historical period consistent with the remaining performance period of approximately three years. The risk-free interest rate was based on the U.S. Treasury rate for a term commensurate with the expected life of the grant. The Company assumed a risk-free interest rate of 2.42% and a range of expected volatilities of 30.5% to 72.6% to estimate the fair value of performance vesting units granted during the three months ended March 31, 2019. Unrecognized compensation expense as of March 31, 2019 related to performance vesting restricted shares was $2.2 million. The expense is expected to be recognized over a weighted average period of 2.76 years.

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7. 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,					
	2019			2018		
	Income	Shares	Per Share	Income	Shares	Per Share
	(In thousands, except share data)					
Basic:						
Net income	$62,242	162,823,997	$0.38	$90,090	180,714,881	$0.50
Effect of dilutive securities:						
Stock options and awards	—	275,412		—	87,420	
Diluted:						
Net income	$62,242	163,099,409	$0.38	$90,090	180,802,301	$0.50

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8. COMMITMENTS AND CONTINGENCIES

Plugging and Abandonment Funds

In connection with the Company’s acquisition in 1997 of the remaining 50% interest in its West Cote Blanche Bay ("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. 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, 2019, the plugging and abandonment trust totaled approximately $3.1 million. At March 31, 2019, the Company had plugged 555 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its minimum plugging obligation.

Firm Transportation and Sales Commitments

The table below presents the firm sales commitments by year:

	(MMBtu per day)
Remaining 2019	469,000
2020	257,000
2021	169,000
2022	61,000
2023	42,000
Thereafter	25,000
Total	1,023,000

The table below presents the firm transportation commitments by year:

	(In thousands)
Remaining 2019	$191,493
2020	287,619
2021	286,657
2022	286,657
2023	281,855
Thereafter	2,394,486
Total	$3,728,767

Other Commitments

Effective October 1, 2014, the Company entered into a Sand Supply Agreement with Muskie Proppant LLC (“Muskie”), a subsidiary of Mammoth Energy, a related party. Effective August 3, 2018, the Company extended the agreement through December 31, 2021. 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 $0.3 million and $0.9 million in non-utilization fees under this agreement during the three months ended March 31, 2019 and 2018, respectively.

Future minimum commitments under this agreement at March 31, 2019 are as follows:

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	(In thousands)
Remaining 2019	$ 18,000
2020	24,000
2021	24,000
Total	$ 66,000

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 Vermilion 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 Vermilion 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 Vermilion 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 Vermilion 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 Vermilion Parish suit. Shortly after the Complaints were filed, certain defendants removed the cases to the United States District Court for the Western District of Louisiana. In both cases, the plaintiffs filed motions to remand the lawsuits to state court, which were ultimately granted by the district courts. However, on May 23, 2018, a group of defendants again removed the Cameron Parish and Vermilion Parish lawsuits to federal court. In response, the plaintiffs again filed motions to remand the cases to state court. The removing defendants have opposed plaintiffs' motions to remand. The motions to remand remain pending, and further action in the cases will be stayed until the courts rule on the motions to remand. Also, shortly after the May 23, 2018 removal, the removing defendants filed motions with the United States Judicial Panel on Multidistrict Litigation (the "MDL Panel") requesting that the Cameron Parish and Vermilion Parish lawsuits be consolidated with 40 similar lawsuits so that pre-trial proceedings in the cases could be coordinated. The MDL Panel denied the motion to consolidate the lawsuits. Due to the procedural posture of lawsuits, the cases are still in their early stages and the parties have conducted very little discovery. As a result, the Company has not had the opportunity to evaluate the applicability of the allegations made in plaintiffs' complaints to the Company's operations and management cannot determine the amount of loss, if any, that may result.

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

9. 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 ("NGLs") 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 NGLs 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, the NYMEX West Texas Intermediate for oil and Mont Belvieu for propane, pentane and ethane. Below is a summary of the Company’s open fixed price swap positions as of March 31, 2019.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
Remaining 2019	NYMEX Henry Hub	1,314,000	$ 2.82
2020	NYMEX Henry Hub	204,000	$ 2.77

	Location	Daily Volume (Bbls/day)	Weighted Average Price
Remaining 2019	NYMEX WTI	2,000	$ 59.44

	Location	Daily Volume (Bbls/day)	Weighted Average Price
Remaining 2019	Mont Belvieu C2	1,000	$ 18.48
Remaining 2019	Mont Belvieu C3	4,000	$ 29.02
Remaining 2019	Mont Belvieu C5	500	$ 54.08

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 2019 - December 2019	NYMEX Henry Hub	30,000	$ 3.10

For a portion of the natural gas fixed price swaps listed above, the counterparty had the option to extend the original terms an additional twelve months for the period January 2019 through December 2019. In December 2018, the counterparties chose to exercise all natural gas fixed price swaps, resulting in an additional 100,000 MMBtu per day at a weighted average price of $3.05 per MMBtu, which is included in the natural gas fixed price swaps listed above.

In addition, the Company entered into natural gas basis swap positions. As of March 31, 2019, the Company had the following natural gas basis swap positions open:

	Gulfport Pays	Gulfport Receives	Daily Volume (MMBtu/day)	Weighted Average Fixed Spread
Remaining 2019	Transco Zone 4	NYMEX Plus Fixed Spread	60,000	$ (0.05)
2020	Transco Zone 4	NYMEX Plus Fixed Spread	60,000	$ (0.05)
2020	Fixed Spread	ONEOK Minus NYMEX	10,000	$ (0.54)

Balance Sheet Presentation

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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, 2019 and December 31, 2018:

	March 31, 2019	December 31, 2018
	(In thousands)	
Short-term derivative instruments - asset	$17,958	$ 21,352
Long-term derivative instruments - asset	$—	$ —
Short-term derivative instruments - liability	$25,921	$ 20,401
Long-term derivative instruments - liability	$287	$ 13,992

Gains and Losses

The following table presents the gain and loss recognized in net loss on natural gas, oil and NGL derivatives in the accompanying consolidated statements of operations for the three months ended March 31, 2019 and 2018.

	Net (loss) gain on derivative instruments	
	Three months ended March 31,	
	2019	2018
	(In thousands)	
Natural gas derivatives	$(16,431)	$(9,696)
Oil derivatives	(454)	(9,147)
Natural gas liquids derivatives	(3,160)	2,314
Total	$(20,045)	$(16,529)

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, 2019		
	Gross Assets (Liabilities) Presented in the Consolidated Balance Sheets	Gross Amounts Subject to Master Netting Agreements	Net Amount
	(In thousands)		
Derivative assets	$17,958	$ (15,899)	$2,059
Derivative liabilities	$(26,208)	$ 15,899	$(10,309)

	As of December 31, 2018		
	Gross Assets (Liabilities) Presented in the	Gross Amounts Subject to Master	Net Amount

	Consolidated Balance Sheets	Netting Agreements	
	(In thousands)		
Derivative assets	$21,352	$ (19,289)	$2,063
Derivative liabilities	$(34,393)	$ 19,289	$(15,104)

Concentration of Credit Risk

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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.

10. FAIR VALUE MEASUREMENTS

The Company records certain financial and non-financial assets and liabilities on the balance sheet at fair value. Fair value is 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. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. Fair value measurements are 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 valuation level as of March 31, 2019 and December 31, 2018:

	March 31, 2019		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Derivative Instruments	$—	$17,958	$ —
Liabilities:			
Derivative Instruments	$—	$26,208	$ —

	December 31, 2018		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Derivative Instruments	$—	$21,352	$ —
Liabilities:			
Derivative Instruments	$—	$34,393	$ —

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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.

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 1 for further discussion of the Company’s asset retirement obligations. Asset retirement obligations incurred during the three months ended March 31, 2019 were approximately $1.0 million.

11. 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 Company's 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, 2019, the carrying value of the outstanding debt represented by the Notes was approximately $2.0 billion, including the unamortized debt issuance cost of approximately $4.2 million related to the 2023 Notes, approximately $8.4 million related to the 2024 Notes, approximately $12.1 million related to the 2025 Notes and approximately $4.9 million related to the 2026 Notes. Based on the quoted market price, the fair value of the Notes was determined to be approximately $1.9 billion at March 31, 2019.

12. REVENUE FROM CONTRACTS WITH CUSTOMERS

Revenue Recognition

The Company’s revenues are primarily derived from the sale of natural gas, oil and condensate and 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. 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. As such, this market pricing may be constrained (i.e., not estimable) at the inception of the contract but will be recognized based on the applicable market pricing, which will be known upon transfer of the goods to the customer. The payment date is usually within 30 days of the end of the calendar month in which the commodity is delivered. 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, and 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 $145.0 million and $210.2 million as of March 31, 2019 and December 31, 2018, respectively, and are reported in accounts receivable - oil and natural gas sales 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.

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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. For the three months ended March 31, 2019, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

13. LEASES

Effective January 1, 2019, the Company adopted Accounting Standards Update ("ASU") No. 2016-02, Leases (Topic 842). The new standard supersedes the previous lease guidance by requiring lessees to recognize a right-of-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year while maintaining substantially similar classifications for financing and operating leases. The Company adopted the new standard on a prospective basis using the simplified transition method permitted by ASU No. 2018-11, Leases (Topic 842): Targeted Improvements. Offsetting right-of-use assets and corresponding lease liabilities recognized by the Company on the adoption date totaled approximately $110 million, representing minimum payment obligations associated with identified leases with contractual durations exceeding one year. No cumulative-effect adjustment to retained earnings was required upon adoption of the new standard. The Company elected the package of practical expedients permitted under the new standard, which among other things, allows for lease and non-lease components in a contract to be accounted for as a single lease component for all asset classes and the carry forward of historical lease classifications.

Nature of Leases

The Company has operating leases associated with drilling rig commitments, pressure pumping services, field offices and other equipment with remaining lease terms with contractual durations in excess of one year. Short-term leases that have an initial term of one year or less are not capitalized.

The Company has entered into contracts for drilling rigs with third parties to ensure rig availability in its key operating areas. The Company has concluded its drilling rig contracts are operating leases as the assets are identifiable and the evaluation that the Company has the right to control the identified assets. The Company's drilling rig commitments are typically structured with an initial term of one to two years and expire at various dates through 2021. These agreements typically include renewal options at the end of the initial term. Due to the nature of the Company's drilling schedules and potential volatility in commodity prices, the Company is unable to determine at commencement with reasonable certainty if the renewal options will be exercised; therefore, renewal options are not considered in the lease term for drilling contracts. The operating lease liabilities associated with these rig commitments are based on the minimum contractual obligations, primarily standby rates, and do not include variable amounts based on actual activity in a given period. Pursuant to the full cost method of accounting, these costs are capitalized as part of oil and natural gas properties on the accompanying consolidated balance sheets. A portion of these costs are borne by other interest owners.

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 and a related party. Pursuant to this agreement, as amended effective July 1, 2018, Stingray Pressure has agreed to provide hydraulic fracturing, stimulation and related completion and rework services to the Company through 2021 and the Company has agreed to pay Stingray Pressure a monthly service fee plus the associated costs of the services provided. The Company has the right to suspend services of one crew and only one crew at any point in time without payment, fee or other obligation associated with the suspended crew, given appropriate notification of suspension. The Company has concluded the agreement with Stingray Pressure is an operating lease due to the implicit identification of assets and and the evaluation that the Company has the right to control the identified assets. The operating lease liability associated with this agreement is based on the minimum contractual obligations, which is the monthly service fee for one crew, and does not include variable amounts based on actual activity in a given period. Pursuant to the full cost method of accounting, these costs are capitalized as part of oil and natural gas properties on the accompanying consolidated balance sheets. A portion of these costs are borne by other interest owners.

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The Company rents office space for its field locations and certain other equipment from third parties, which expire at various dates through 2024. These agreements are typically structured with non-cancelable terms of one to five years. The Company has determined these agreements represent operating leases with a lease term that equals the primary non-cancelable contract term. The Company has included any renewal options that it has determined are reasonably certain of exercise in the determination of the lease terms.

Discount Rate

As most of the Company's leases do not provide an implicit rate, the Company uses its incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. The Company's incremental borrowing rate reflects the estimated rate of interest that it would pay to borrow on a collateralized basis over a similar term an amount equal to the lease payments in a similar economic environment.

Maturities of operating lease liabilities as of March 31, 2019 were as follows:

	(In thousands)
Remaining 2019	$ 40,596
2020	28,578
2021	22,569
2022	115
2023	90
Thereafter	30
Total lease payments	$ 91,978
Less: Imputed interest	(3,524)
Total	$ 88,454

Lease cost for the three months ended March 31, 2019 consisted of the following:

	(In thousands)
Operating lease cost	$ 8,536
Operating lease cost - related party	5,610
Variable lease cost	429
Variable lease cost - related party	31,453
Total lease cost[1]	$ 46,028

(1) The majority of the Company's total lease cost was capitalized to the full cost pool, and an immaterial amount was included in general and administrative expenses in the accompanying consolidated income statements.

Supplemental cash flow information for the three months ended March 31, 2019 related to leases was as follow:

Cash paid for amounts included in the measurement of lease liabilities	(In thousands)
Operating cash flows from operating leases	$ 52
Investing cash flow from operating leases	$ 4,858
Investing cash flow from operating leases - related party	$ 6,545

The weighted-average remaining lease term as of March 31, 2019 was 2.42 years. The weighted-average discount rate used to determine the operating lease liability as of March 31, 2019 was 3.77%.

14. INCOME TAXES

The Company records its quarterly tax provision based on an estimate of the annual effective tax rate expected to apply to continuing operations for the various jurisdictions in which it operates. The tax effects of certain items, such as tax rate changes, significant unusual or infrequent items, and certain changes in the assessment of the realizability of deferred taxes, are recognized as discrete items in the period in which they occur and are excluded from the estimated annual effective tax rate.

For the three months ended March 31, 2019, the Company's estimated annual effective tax rate remained nominal as a result of the full valuation allowance on deferred tax assets. Based on the Company's estimated results for the period ending March 31, 2019, the Company anticipates remaining in a net deferred tax asset position. Based on the available positive and negative evidence, the Company expects to maintain a full valuation allowance as it cannot objectively assert that the deferred tax assets are more likely than not to be realized. During the quarter, the Company generated sufficient earnings and is no longer in a cumulative loss position as evaluated based on the generally prescribed view of a rolling 12 quarter assessment. However, there remains some uncertainty around the Company’s ability to fully utilize NOL carryforwards prior to expiration and potential impacts of Internal Revenue Code Section 382 (“Section 382”) ownership changes that would limit the amount of NOL carryforward available for use against future taxable income. Each reporting period, Management evaluates all positive and negative evidence and continues to maintain that a release of the valuation allowance is possible during an interim period in 2019. The Company determined that the negative evidence regarding the uncertainty of the possible Section 382 limitations warranted maintaining the full valuation allowance at March 31, 2019.

The release of the valuation allowance would result in the recognition of certain net deferred tax assets and a decrease to income tax expense for the period the release is recorded. However, the exact timing and amount of any potential valuation allowance release is subject to change based on the levels of profitability that the Company is able to actually achieve.

The Company’s ability to utilize NOL carryforwards and other tax attributes to reduce future federal taxable income is subject to potential limitations under Section 382 and its related tax regulations. The utilization of these attributes may be limited if certain ownership changes by 5% stockholders (as defined in Treasury regulations pursuant to Section 382) and the effects of stock issuances by the Company during any three-year period result in a cumulative change of more than 50% in the beneficial ownership of Gulfport. The Company is currently conducting a Section 382 analysis to determine if an ownership change has occurred. If it is determined that an ownership change has occurred under these rules, the Company would generally be subject to an annual limitation on the use of pre-ownership change NOL carryforwards and certain other losses and/or credits. In addition, certain future transactions regarding the Company's equity, including the cumulative effects of small transactions as well as transactions beyond the Company’s control, could cause an ownership change and therefore a potential limitation on the annual utilization of their deferred tax assets. The results of the Section 382 analysis will provide further evidence for the Company to consider in determining whether a full, partial or limited release of the valuation allowance is warranted in future periods.

15. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

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, 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 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, 2019				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$7,040	$10,955	$ 1	$—	$17,996
Accounts receivable - oil and natural gas sales	93,698	51,298	—	—	144,996
Accounts receivable - joint interest and other	12,084	12,496	—	—	24,580
Accounts receivable - intercompany	694,036	388,797	—	(1,082,833)	—
Prepaid expenses and other current assets	11,412	1,148	—	—	12,560
Short-term derivative instruments	17,958	—	—	—	17,958
Total current assets	836,228	464,694	1	(1,082,833)	218,090
Property and equipment:					
Oil and natural gas properties, full-cost accounting	7,238,631	3,074,222	—	(729)	10,312,124
Other property and equipment	92,135	4,069	—	—	96,204
Accumulated depletion, depreciation, amortization and impairment	(4,757,774)	(40)	—	—	(4,757,814)
Property and equipment, net	2,572,992	3,078,251	—	(729)	5,650,514
Other assets:					
Equity investments and investments in subsidiaries	2,963,629	—	48,004	(2,767,514)	244,119
Inventories	9,264	1,754	—	—	11,018
Operating lease assets	29,795	—	—	—	29,795
Operating lease assets - related parties	58,659	—	—	—	58,659
Other assets	12,187	1,127	—	—	13,314
Total other assets	3,073,534	2,881	48,004	(2,767,514)	356,905
Total assets	$6,482,754	$3,545,826	$ 48,005	$(3,851,076)	$6,225,509
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$449,459	$118,725	$ —	$—	$568,184
Accounts payable - intercompany	388,879	693,826	129	(1,082,834)	—
Short-term derivative instruments	25,921	—	—	—	25,921
Current portion of operating lease liabilities	27,983	—	—	—	27,983
Current portion of operating lease liabilities - related parties	20,618	—	—	—	20,618
Current maturities of long-term debt	656	—	—	—	656
Total current liabilities	913,516	812,551	129	(1,082,834)	643,362
Long-term derivative instruments	287	—	—	—	287
Asset retirement obligation - long-term	69,991	12,909	—	—	82,900
Deferred tax liability	3,127	—	—	—	3,127
Non-current operating lease liabilities	1,812	—	—	—	1,812
Non-current operating lease liabilities - related parties	38,041	—	—	—	38,041
Long-term debt, net of current maturities	2,087,714	—	—	—	2,087,714

Total liabilities	3,114,488	825,460	129	(1,082,834)	2,857,243
Stockholders' equity:					
Common stock	1,594	—	—	—	1,594
Paid-in capital	4,202,023	1,915,598	262,059	(2,177,657)	4,202,023
Accumulated other comprehensive loss	(52,225)	—	(50,076)	50,076	(52,225)
(Accumulated deficit) retained earnings	(783,126)	804,768	(164,107)	(640,661)	(783,126)
Total stockholders' equity	3,368,266	2,720,366	47,876	(2,768,242)	3,368,266
Total liabilities and stockholders' equity	$6,482,754	$3,545,826	$ 48,005	$(3,851,076)	$6,225,509

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CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2018				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$25,585	$26,711	$ 1	$—	$52,297
Accounts receivable - oil and natural gas sales	146,075	64,125	—	—	210,200
Accounts receivable - joint interest and other	16,212	6,285	—	—	22,497
Accounts receivable - intercompany	671,633	319,464	—	(991,097)	—
Prepaid expenses and other current assets	8,433	2,174	—	—	10,607
Short-term derivative instruments	21,352	—	—	—	21,352
Total current assets	889,290	418,759	1	(991,097)	316,953
Property and equipment:					
Oil and natural gas properties, full-cost accounting,	7,044,550	2,983,015	—	(729)	10,026,836
Other property and equipment	91,916	751	—	—	92,667
Accumulated depletion, depreciation, amortization and impairment	(4,640,059)	(39)	—	—	(4,640,098)
Property and equipment, net	2,496,407	2,983,727	—	(729)	5,479,405
Other assets:					
Equity investments and investments in subsidiaries	2,856,988	—	44,259	(2,665,126)	236,121
Inventories	3,620	1,134	—	—	4,754
Other assets	12,624	1,178	—	1	13,803
Total other assets	2,873,232	2,312	44,259	(2,665,125)	254,678
Total assets	$6,258,929	$3,404,798	$ 44,260	$(3,656,951)	$6,051,036
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$419,107	$99,273	$ —	$—	$518,380
Accounts payable - intercompany	320,259	670,708	130	(991,097)	—
Short-term derivative instruments	20,401	—	—	—	20,401
Current maturities of long-term debt	651	—	—	—	651
Total current liabilities	760,418	769,981	130	(991,097)	539,432
Long-term derivative instruments	13,992	—	—	—	13,992
Asset retirement obligation - long-term	66,859	13,093	—	—	79,952
Deferred tax liability	3,127	—	—	—	3,127
Long-term debt, net of current maturities	2,086,765	—	—	—	2,086,765
Total liabilities	2,931,161	783,074	130	(991,097)	2,723,268
Stockholders' equity:					
Common stock	1,630	—	—	—	1,630
Paid-in capital	4,227,532	1,915,598	261,626	(2,177,224)	4,227,532
Accumulated other comprehensive loss	(56,026)	—	(53,783)	53,783	(56,026)
(Accumulated deficit) retained earnings	(845,368)	706,126	(163,713)	(542,413)	(845,368)

Total stockholders’ equity	3,327,768	2,621,724	44,130	(2,665,854)	3,327,768
Total liabilities and stockholders’ equity	$6,258,929	$3,404,798	$ 44,260	$(3,656,951)	$6,051,036

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three months ended March 31, 2019				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$186,246	$134,332	$ —	$—	$320,578
Costs and expenses:					
Lease operating expenses	14,893	4,914	—	—	19,807
Production taxes	3,261	4,660	—	—	7,921
Midstream gathering and processing expenses	43,299	26,983	—	—	70,282
Depreciation, depletion and amortization	118,432	1	—	—	118,433
General and administrative expenses	12,232	(675)	1	—	11,558
Accretion expense	951	116	—	—	1,067
	193,068	35,999	1	—	229,068
(LOSS) INCOME FROM OPERATIONS	(6,822)	98,333	(1)	—	91,510
OTHER (INCOME) EXPENSE:					
Interest expense	34,424	(304)	—	—	34,120
Interest income	(147)	(5)	—	—	(152)
(Income) loss from equity method investments and investments in subsidiaries	(102,914)	—	393	98,248	(4,273)
Other income	(427)	—	—	—	(427)
	(69,064)	(309)	393	98,248	29,268
INCOME (LOSS) BEFORE INCOME TAXES	62,242	98,642	(394)	(98,248)	62,242
INCOME TAX EXPENSE	—	—	—	—	—
NET INCOME (LOSS)	$62,242	$98,642	$ (394)	$ (98,248)	$ 62,242

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three months ended March 31, 2018				
	Parent	Guarantors	Non-Guarantor	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 expenses	45,666	18,527	—	—	64,193
Depreciation, depletion and amortization	111,017	1	—	—	111,018
General and administrative expenses	13,811	(713)	1	—	13,099
Accretion expense	790	214	—	—	1,004
	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 COMPREHENSIVE INCOME (LOSS)
(Amounts in thousands)

	Three months ended March 31, 2019				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$62,242	$ 98,642	$ (394)	$ (98,248)	$ 62,242
Foreign currency translation adjustment	3,801	94	3,707	(3,801)	3,801
Other comprehensive income	3,801	94	3,707	(3,801)	3,801
Comprehensive income (loss)	$66,043	$ 98,736	$ 3,313	$ (102,049)	$ 66,043

	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	(5,503)	(187)	(5,316)	5,503	(5,503)
Comprehensive income (loss)	$84,587	$ 86,499	$ (5,647)	$ (80,852)	$ 84,587

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Three months ended March 31, 2019				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$164,448	$ 20,612	$ (1)	$ 1	$ 185,060
Net cash used in investing activities	(154,490)	(36,368)	(432)	432	(190,858)
Net cash (used in) provided by financing activities	(28,503)	—	433	(433)	(28,503)
Net decrease in cash, cash equivalents and restricted cash	(18,545)	(15,756)	—	—	(34,301)
Cash, cash equivalents and restricted cash at beginning of period	25,585	26,711	1	—	52,297
Cash, cash equivalents and restricted cash at end of period	$7,040	$ 10,955	$ 1	$ —	$ 17,996

	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 investing activities	(231,024)	(75,847)	(1,569)	1,569	(306,871)
Net cash provided by 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

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16. RECENT ACCOUNTING PRONOUNCEMENTS

In February 2016, the Financial Accounting Standards Board ("FASB") issued ASU No. 2016-02, Leases (Topic 842). The standard supersedes the previous lease guidance by requiring lessees to recognize a right-to-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year while maintaining substantially similar classifications for financing and operating leases. Subsequent to ASU 2016-02, the FASB issued several related ASU's to clarify the application of the lease standard. The Company adopted the new standard as of January 1, 2019 on a prospective basis using the simplified transition method permitted by ASU 2018-11, Leases (Topic 842): Targeted Improvements. The comparative information has not been restated and continues to be reported under the historic accounting standards in effect for those periods. See Note 13 for further discussion of the lease standard.

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 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 assessed the impact of the ASU on its consolidated financial statements and related disclosures, and determined there was no material impact.

In August 2018, the FASB issued ASU No. 2018-13, Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement which removes, modifies, and adds certain disclosure requirements on fair value measurements. The amendment will be effective for reporting periods beginning after December 15, 2019, and early adoption is permitted. The Company is currently assessing the impact of the ASU on its consolidated financial statements and related disclosures.

In August 2018, the FASB also issued ASU No. 2018-15 , Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract, which aligns the accounting for costs associated with implementing a cloud computing arrangement in a hosting arrangement that is a service contract with the accounting for implementation costs incurred to develop or obtain internal-use software. The amendment will be effective for reporting periods beginning after December 15, 2019, and early adoption is permitted. The Company is currently assessing the impact of the ASU on its consolidated financial statements and related disclosures.

In November 2018, the FASB also issued ASU No. 2018-18, Collaborative Arrangements (Topic 808): Clarifying the Interaction Between Topic 808 and Topic 606, which provides guidance on how to assess whether certain transactions between participants in a collaborative arrangement should be accounted for within the ASU No. 2014-09 revenue recognition standard discussed above. The amendment will be effective for reporting periods beginning after December 15, 2019, 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 2019, the Company entered into fixed price swaps for 2019 for approximately 3,000 Bbls of oil per day at a weighted average price of $61.55 per Bbl and for approximately 500 Bbls of C5 pentane per day at a weighted average price of $53.34 per Bbl. For 2020, the Company entered into fixed price swaps for approximately 6,000 Bbls of oil per day at a weighted average price of $59.82 per Bbl. The Company's fixed price swap contracts are tied to the commodity prices on

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NYMEX WTI for oil and Mont Belvieu for 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 oil or Mont Belvieu for pentane.

Stock Repurchase Program

In April 2019, the Company repurchased 0.2 million shares for a total cost of approximately $1.8 million. As of April 26, 2019, the Company has repurchased an aggregate of 3.8 million shares for a total cost of $30.0 million, and had an additional $370.0 million authorized for repurchases under its new share repurchase program.

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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, or NGLs, 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 21.9% equity interest in Mammoth Energy Services, Inc., or Mammoth Energy, an energy 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.

2019 Operational and Other Highlights

- During the three months ended March 31, 2019, we spud six gross (5.6 net) wells in the Utica Shale and participated in one additional gross (0.3 net) well that was drilled by another operator on our Utica Shale acreage. In addition, during the three months ended March 31, 2019, we spud four gross (3.1 net) wells in the SCOOP and participated in an additional 15 gross (0.2 net) wells that were drilled by other operators on our SCOOP acreage. Of the ten new wells we spud, at March 31, 2019, seven were in various stages of completion and three were being drilled. In addition, six gross and net operated wells were turned-to-sales in our Utica Shale operating area and three gross (2.8

net) operated wells were turned-to-sales in our SCOOP operating area during the three months ended March 31, 2019.

- During the three months ended March 31, 2019, we decreased our unit general and administrative expense by 9% to $0.10 per Mcfe from $0.11 per Mcfe during the three months ended March 31, 2018.

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- In January 2019, our board of directors approved a new stock repurchase program to acquire up to $400 million of our outstanding common stock within a 24 month period, which we believe underscores the confidence we have in our business model, financial performance and asset base. As of April 26, 2019, we have repurchased approximately 3.8 million shares of our outstanding common stock for a total of approximately $30.0 million.

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2019 Production and Drilling Activity

During the three months ended March 31, 2019, our total net production was 102,079,235 thousand cubic feet, or Mcf, of natural gas, 611,762 barrels of oil and 55,830,348 gallons of NGLs for a total of 113,726 million cubic feet of natural gas equivalent, or MMcfe, as compared to 102,041,668 Mcf of natural gas, 756,899 barrels of oil and 65,755,864 gallons of NGLs, or 115,977 MMcfe, for the three months ended March 31, 2018. Our total net production averaged approximately 1,263.6 MMcfe per day during the three months ended March 31, 2019, as compared to 1,288.6 MMcfe per day during the same period in 2018. The 2% decrease in production is largely the result of natural production declines and the timing of our 2018 and 2019 capital activity.

Utica Shale. From January 1, 2019 through March 31, 2019, we spud six gross (5.6 net) wells in the Utica Shale, of which one was being drilled and five were in various stages of completion at March 31, 2019. We also participated in one additional gross (0.3 net) well that was drilled by another operator on our Utica Shale acreage. From April 1, 2019 through April 26, 2019, we spud two gross (1.15 net) wells in the Utica Shale.

As of April 26, 2019, we had one operated horizontal rig running in the play. We currently intend to spud 13 to 15 gross (10 to 11 net) horizontal wells, and commence sales from 47 to 51 gross (40 to 45 net) horizontal wells, on our Utica Shale acreage in 2019.

Aggregate net production from our Utica Shale acreage during the three months ended March 31, 2019 was approximately 89,428 MMcfe, or an average of 993.6 MMcfe per day, of which 96% was from natural gas and 4% was from oil and NGLs.

SCOOP. From January 1, 2019 through March 31, 2019, we spud four gross (3.1 net) wells in the SCOOP, of which two were being drilled and two were in various stages of completion at March 31, 2019. We also participated in an additional 15 gross (0.2 net) wells that were drilled by other operators on our SCOOP acreage. From April 1, 2019 through April 26, 2019, we spud one gross (0.78 net) well.

As of April 26, 2019, we had two operated horizontal rigs running on our SCOOP acreage. We currently intend to spud nine to ten gross (seven to eight net) horizontal wells, and commence sales from 15 to 17 gross (14 to 15 net) horizontal wells, on our SCOOP acreage in 2019.

Aggregate net production from our SCOOP acreage during the three months ended March 31, 2019 was approximately 23,394 MMcfe, or an average of 259.9 MMcfe per day, of which 70% was from natural gas and 30% was from oil and NGLs.

WCBB. From January 1, 2019 through April 26, 2019, we did not spud any new wells or recomplete any wells. Aggregate net production from the WCBB field during the three months ended March 31, 2019 was approximately 709 MMcfe, or an average of 7.9 MMcfe per day, all of which was from oil.

East Hackberry Field. From January 1, 2019 through April 26, 2019, we did not spud any new wells or recomplete any wells. Aggregate net production from the East Hackberry field during the three months ended March 31, 2019 was approximately 85.4 MMcfe, or an average of 948.9 Mcfe per day, all of which was from oil.

West Hackberry Field. From January 1, 2019 through April 26, 2019, we did not spud any new wells in our West Hackberry field. Aggregate net production from the West Hackberry field during the three months ended March 31, 2019 was approximately 17.9 MMcfe, or an average of 198.6 Mcfe per day, all of which was from oil.

We do not anticipate any material activities in our Southern Louisiana fields during 2019.

Niobrara Formation. From January 1, 2019 through April 26, 2019, there were no wells spud on our Niobrara Formation acreage. Aggregate net production was approximately 17.7 MMcfe, or an average of 196.3 Mcfe per day during the three months ended March 31, 2019, all of which was from oil.

Bakken. As of March 31, 2019, we had an interest 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, 2019 was approximately 73.3 MMcfe, or an average of 814.9 Mcfe per day, of which 80% was from oil and 20% was from natural gas and natural gas liquids.

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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 $2.9 billion at both March 31, 2019 and December 31, 2018. 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. At March 31, 2019, 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, 2019. 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 Accounting Standards Codification, or 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.

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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 natural gas, oil and condensate and NGL's 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. has prepared reserve reports of our reserve estimates at December 31, 2018 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. Quarterly, 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, 2019, a valuation allowance of $200.4 million had been provided against the net deferred tax asset.

Revenue Recognition. Our revenues are primarily derived from the sale of natural gas, oil and condensate and NGLs. Sales of natural gas, oil and condensate and NGLs are recognized in the period that the performance obligations are satisfied. We generally consider 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. 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. As such, this market pricing may be constrained (i.e., not estimable) at the inception of the contract but will be recognized based on the applicable market pricing, which will be known upon transfer of the goods to the customer. The payment date is typically within 30 days of the end of the calendar month in which the commodity is delivered.

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 ASC 815 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, 2019.

RESULTS OF OPERATIONS

Comparison of the Three Months Ended March 31, 2019 and 2018

We reported net income of $62.2 million for the three months ended March 31, 2019 as compared to net income of $90.1 million for the three months ended March 31, 2018. This $27.8 million period-to-period decrease was due primarily to a $4.8 million decrease in oil and natural gas revenues, a $9.3 million decrease in income from equity method investments, a $6.1 million increase in midstream gathering and processing expenses and a $7.4 million increase in depreciation, depletion and amortization, partially offset by a $1.5 million decrease in general and administrative expense for the three months ended March 31, 2019 as compared to the three months ended March 31, 2018.

Natural Gas, Oil and NGL Revenues. For the three months ended March 31, 2019, we reported oil and natural gas revenues of $320.6 million as compared to oil and natural gas revenues of $325.4 million during the same period in 2018. This $4.8 million, or 1%, decrease in revenues was primarily attributable to the following:

- A $13.2 million decrease in oil and condensate sales without the impact of derivatives due to a 12% decrease in oil and condensate market prices and a 19% decrease in oil and condensate sales volumes.

- A $14.7 million decrease in natural gas liquids sales without the impact of derivatives due to a 19% decrease in natural gas liquids market prices and a 15% decrease in natural gas liquids sales volumes.

- A $26.6 million increase in natural gas sales without the impact of derivatives due to an 11% increase in natural gas market prices.

- A $3.5 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, $33.7 million was due to unfavorable changes in settlements related to our derivative positions, partially offset by a $30.2 million favorable change in the fair value of our open derivative positions in each period. The favorable change in fair value of our open derivative positions is primarily a result of the decrease in the forward curve prices for natural gas from the previous reporting period.

The following table summarizes our oil and natural gas production and related pricing for the three months ended March 31, 2019, as compared to such data for the three months ended March 31, 2018:

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	Three months ended March 31,	
	2019	2018
	($ In thousands)	
Natural gas sales		
Natural gas production volumes (MMcf)	102,079	102,042
Total natural gas sales	$276,016	$249,399
Natural gas sales without the impact of derivatives ($/Mcf)	$2.70	$2.44
Impact from settled derivatives ($/Mcf)	$(0.25)	$0.16
Average natural gas sales price, including settled derivatives ($/Mcf)	$2.45	$2.60
Oil and condensate sales		
Oil and condensate production volumes (MBbls)	612	757
Total oil and condensate sales	$32,482	$45,686
Oil and condensate sales without the impact of derivatives ($/Bbl)	$53.10	$60.36
Impact from settled derivatives ($/Bbl)	$0.03	$(5.64)
Average oil and condensate sales price, including settled derivatives ($/Bbl)	$53.13	$54.72
Natural gas liquids sales		
Natural gas liquids production volumes (MGal)	55,830	65,756
Total natural gas liquids sales	$32,125	$46,836
Natural gas liquids sales without the impact of derivatives ($/Gal)	$0.58	$0.71
Impact from settled derivatives ($/Gal)	$0.01	$(0.04)
Average natural gas liquids sales price, including settled derivatives ($/Gal)	$0.59	$0.67
Natural gas, oil and condensate and natural gas liquids sales		
Natural gas equivalents (MMcfe)	113,726	115,977
Total natural gas, oil and condensate and natural gas liquids sales	$340,623	$341,921
Natural gas, oil and condensate and natural gas liquids sales without the impact of derivatives ($/Mcfe)	$3.00	$2.95
Impact from settled derivatives ($/Mcfe)	$(0.22)	$0.07
Average natural gas, oil and condensate and natural gas liquids sales price, including settled derivatives ($/Mcfe)	$2.78	$3.02
Production Costs:		
Average production costs ($/Mcfe)	$0.17	$0.16
Average production taxes ($/Mcfe)	$0.07	$0.06
Average midstream gathering and processing ($/Mcfe)	$0.62	$0.55
Total production costs, midstream costs and production taxes ($/Mcfe)	$0.86	$0.77

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Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $19.8 million for the three months ended March 31, 2019 from $18.9 million for the three months ended March 31, 2018. This $0.9 million increase was primarily the result of an increase in expenses related to location and facility repairs and maintenance, ad valorem taxes and contract labor, partially offset by a decrease in surface rentals, transportation and workover expenses.

Production Taxes. Production taxes increased $1.0 million to $7.9 million for the three months ended March 31, 2019 from $6.9 million for the three months ended March 31, 2018. This increase was due primarily to an increase in the production tax rates associated with our SCOOP production.

Midstream Gathering and Processing Expenses. Midstream gathering and processing expenses increased $6.1 million to $70.3 million for the three months ended March 31, 2019 from $64.2 million for the same period in 2018. This increase was primarily attributable to routine contract escalations associated with our Utica Shale production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $118.4 million for the three months ended March 31, 2019, and consisted of $115.2 million in depletion of oil and natural gas properties and $3.2 million in depreciation of other property and equipment, as compared to total DD&A expense of $111.0 million for the three months ended March 31, 2018. This increase was due to an increase in our full cost pool and a decrease in our total proved reserves volumes used to calculate our total DD&A expense, partially offset by a decrease in our production.

General and Administrative Expenses. Net general and administrative expenses decreased to $11.6 million for the three months ended March 31, 2019 from $13.1 million for the three months ended March 31, 2018. This $1.5 million decrease was due to decreases in consulting fees and travel expense, partially offset by increases in franchise taxes and computer support.

Interest Expense. Interest expense remained relatively flat at $34.1 million for the three months ended March 31, 2019 as compared to $34.0 million for the three months ended March 31, 2018. In addition, total weighted average debt outstanding under our revolving credit facility was $77.3 million for the three months ended March 31, 2019 as compared to $87.1 million debt outstanding under such facility for the same period in 2018. As of March 31, 2019, amounts borrowed under our revolving credit facility bore interest at a weighted average rate of 3.99%. In addition, we capitalized approximately $0.8 million and $0.8 million in interest expense to undeveloped oil and natural gas properties during the three months ended March 31, 2019 and 2018, respectively.

Income Taxes. As of March 31, 2019, we had a federal net operating loss carryforward of approximately $838.2 million from prior years, in addition to numerous temporary differences, which gave rise to a net deferred tax asset. Quarterly, 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, 2019, a valuation allowance of $200.4 million had been provided against the net deferred tax asset, with the exception of certain state net operating losses that we expect to be able to utilize with NOL carrybacks.

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 $185.1 million for the three months ended March 31, 2019 as compared to $226.3 million for the same period in 2018. This decrease was primarily the result of a decrease in cash receipts from our oil and natural gas purchasers due to a 10% decrease in net revenues after giving effect to settled derivative instruments and an increase in our operating expenses. In addition, we received $1.2 million in dividends from our investment in Mammoth Energy.

Net cash used in investing activities for the three months ended March 31, 2019 was $190.9 million as compared to $306.9 million for the same period in 2018. During the three months ended March 31, 2019, we spent $186.7 million in additions to oil and natural gas properties, of which $75.8 million was spent on our 2019 drilling and completion activities, $61.5 million was spent on expenses attributable to wells spud, completed and recompleted during 2018, $22.7 million was spent on lease

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related costs, primarily the acquisition of leases in the Utica Shale and $14.8 million was spent on tubulars, with the remainder attributable mainly to future location development and capitalized general and administrative expenses. During the three months ended March 31, 2019, we invested $0.4 million in Grizzly. We did not make any investments in our other equity investments during the three months ended March 31, 2019.

Net cash used in financing activities for the three months ended March 31, 2019 was $28.5 million as compared to net cash provided by financing activities of $99.6 million for the same period in 2018. The 2019 amount used in financing activities is primarily attributable to purchases under our stock repurchase program of approximately $28.3 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, 2019, we had a borrowing base of $1.4 billion, with an elected commitment of $1.0 billion, and $45.0 million in borrowings outstanding. Total funds available for borrowing under our revolving credit facility, after giving effect to an aggregate of $271.1 million of outstanding letters of credit, were $683.9 million as of March 31, 2019. 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 0.25% to 1.25%, 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 1.25% to 2.25%, 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. At March 31, 2019, amounts borrowed under our credit facility bore interest at a weighted average rate of 3.99%.

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, 2019.

Senior Notes.

In April 2015, we issued an aggregate of $350.0 million in principal amount of our Senior Notes due 2023, or the 2023 Notes. 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.

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On October 14, 2016, we issued an aggregate of $650.0 million in principal amount of our Senior Notes due 2024, or the 2024 Notes. Interest on the 2024 Notes accrues at a rate of 6.000% per annum on the outstanding principal amount thereof from October 14, 2016, payable semi-annually on April 15 and October 15 of each year, commencing on April 15, 2017. The 2024 Notes will mature on October 15, 2024.

On December 21, 2016, we issued an aggregate of $600.0 million in principal amount of our Senior Notes due 2025, or the 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.

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 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, 2019, the total borrowings under the construction loan were approximately $23.0 million.

Capital Expenditures.

Our recent capital commitments have been primarily for the execution of our drilling programs, for acquisitions in the Utica Shale and our SCOOP acquisition in 2017, 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, 2018, 55.4% 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, 2019 through March 31, 2019, we spud six gross (5.6 net) wells in the Utica Shale. As of April 26, 2019, we had one operated horizontal rig drilling in the play. We currently expect to spud 13 to 15 gross (10 to 11 net) horizontal wells, and commence sales from 47 to 51 gross (40 to 45 net) horizontal wells, on our Utica Shale acreage in 2019. We also anticipate an additional two to three net horizontal wells will be drilled, and sales commenced from two to three net horizontal wells, on our Utica Shale acreage by other operators during 2019.

From January 1, 2019 through March 31, 2019, we spud four gross (3.1 net) wells in the SCOOP. As of April 26, 2019, we had two operated horizontal rigs drilling in the play. We currently expect to spud nine to ten gross (seven to eight net) horizontal wells, and commence sales from 15 to 17 gross (14 to 15 net) horizontal wells, on our SCOOP acreage in 2019. We also anticipate one to two net wells will be drilled, and sales commenced from one to two net wells on our SCOOP acreage by other operators during 2019.

From January 1, 2019 through April 26, 2019, no new wells were spud at our WCBB field or in our Hackberry fields. During 2019, we do not anticipate any material activities in our Southern Louisiana fields.

From January 1, 2019 through April 26, 2019, no new wells were spud on our Niobrara Formation acreage. We do not currently anticipate any capital expenditures in the Niobrara Formation in 2019.

As of March 31, 2019, our net investment in Grizzly was approximately $48.0 million. We do not currently anticipate any material capital expenditures in 2019 related to Grizzly's activities.

We had no capital expenditures during the three months ended March 31, 2019 related to our interests in Thailand. We do not currently anticipate any capital expenditures in Thailand in 2019.

In response to current declining forward natural gas prices, we are shifting to building an organization that is focused on disciplined capital allocation, cash flow generation and a commitment to executing a thoughtful, clearly communicated business plan that enhances value for all of our stockholders. We plan to maximize results with the core assets in our portfolio today and focus on returns that will allow us to operate within our cash flow in 2019. As a result, we currently expect to reduce our planned capital expenditures by approximately 29% as compared to 2018. Our total capital expenditures for 2019 are currently estimated to be in the range of $525.0 million to $550.0 million for drilling and completion expenditures, with activity weighted to the first half of the year, of which $254.9 million was spent as of March 31, 2019. In addition, we currently expect to spend $40.0 to $50.0 million in 2019 for non-drilling and completion expenditures, which includes acreage expenses, primarily lease extensions in the Utica Shale, of which $20.1 million was spent as of March 31, 2019. The 2019 range of capital expenditures is lower than the $814.7 million spent in 2018, 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, as well as to generate free cash flow.

In January 2019, our board of directors approved a new stock repurchase program to acquire up to $400 million of our outstanding common stock within a 24 month period. We intend to purchase shares under the repurchase program opportunistically with available funds primarily from cash flow from operations and sale of non-core assets while maintaining sufficient liquidity to fund our capital development programs.

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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 the 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, 2019.

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. Beginning in 2009, we can access the trust for use in plugging and abandonment charges associated with the property. As of March 31, 2019, the plugging and abandonment trust totaled approximately $3.1 million. At March 31, 2019, we have plugged 555 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our minimum plugging obligation.

In January 2019, our board of directors approved a new stock repurchase program to acquire up to $400 million of our outstanding common stock within a 24 month period. Purchases under the 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 2019 capital development program. This repurchase program may be suspended from time to time, modified, extended or discontinued by our board of directors at any time.

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, 2018.

Off-balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of March 31, 2019, our material off-balance sheet arrangements and transactions include $271.1 million in letters of credit outstanding against our 2019 revolving credit facility and $43.6 million in surety bonds issued as financial assurance on midstream firm transportation agreements. Management believes these items will expire without being funded. There are no other transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our capital resources. See Note 8 to our consolidated financial statements for further discussion of the various financial guarantees we have issued.

New Accounting Pronouncements

In February 2016, the FASB issued Accounting Standards Update, or ASU, No. 2016-02, Leases (Topic 842). The standard supersedes the previous lease guidance by requiring lessees to recognize a right-to-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year while maintaining substantially similar classifications for financing and operating leases. Subsequent to ASU 2016-02, the FASB issued several related ASU's to clarify the application of the lease standard. We adopted the new standard as of January 1, 2019 on a prospective basis using the simplified transition method permitted by ASU 2018-11, Leases (Topic 842): Targeted Improvements. The comparative information has not been restated and continues to be reported under the historic accounting standards in effect for those periods. See Note 13 to our consolidated financial statements for further discussion of the lease standard.

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. 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 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 assessed the impact of the ASU on our consolidated financial statements and related disclosures, and determined there was no material impact.

In August 2018, the FASB issued ASU No. 2018-13, Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement which removes, modifies, and adds certain disclosure requirements on fair value measurements. The amendment will be effective for reporting periods beginning after December 15, 2019, and early adoption is permitted. We are currently assessing the impact of the ASU on our consolidated financial statements and related disclosures

In August 2018, the FASB also issued ASU No. 2018-15 , Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract, which aligns the accounting for costs associated with implementing a cloud computing arrangement in a hosting arrangement that is a service contract with the accounting for implementation costs incurred to develop or obtain internal-use software. The amendment will be effective for reporting periods beginning after December 15, 2019, and early adoption is permitted. We are currently assessing the impact of the ASU on our consolidated financial statements and related disclosures.

In November 2018, the FASB also issued ASU No. 2018-18, Collaborative Arrangements (Topic 808): Clarifying the Interaction Between Topic 808 and Topic 606, which provides guidance on how to assess whether certain transactions between participants in a collaborative arrangement should be accounted for within the ASU No. 2014-09 revenue recognition standard discussed above. The amendment will be effective for reporting periods beginning after December 15, 2019, 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.

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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 2018, WTI prices ranged from $44.48 to $77.41 per barrel and the Henry Hub spot market price of natural gas ranged from $2.49 to $6.24 per MMBtu. On May 1, 2019, the WTI posted price for crude oil was $63.30 per Bbl and the Henry Hub spot market price of natural gas was $2.66 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, 2019:

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
Remaining 2019	NYMEX Henry Hub	1,314,000	$ 2.82
2020	NYMEX Henry Hub	204,000	$ 2.77

	Location	Daily Volume (Bbls/day)	Weighted Average Price
Remaining 2019	NYMEX WTI	2,000	$ 59.44

	Location	Daily Volume (Bbls/day)	Weighted Average Price
Remaining 2019	Mont Belvieu C2	1,000	$ 18.48
Remaining 2019	Mont Belvieu C3	4,000	$ 29.02
Remaining 2019	Mont Belvieu C5	500	$ 54.08

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 volumes.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
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. In December 2018, the counterparties chose to exercise all natural gas fixed price swaps, resulting in an additional 100,000 MMBtu per day at a weighted average price of $3.05 per MMBtu, which is included in the natural gas fixed price swaps listed above

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In addition, we have entered into natural gas basis swap positions. As of March 31, 2019, we had the following natural gas basis swap positions open:

	Gulfport Pays	Gulfport Receives	Daily Volume (MMBtu/day)	Weighted Average Fixed Spread
Remaining 2019	Transco Zone 4	NYMEX Plus Fixed Spread	60,000	$ (0.05)
2020	Transco Zone 4	NYMEX Plus Fixed Spread	60,000	$ (0.05)
2020	Fixed Spread	ONEOK Minus NYMEX	10,000	$ (0.54)

Under our 2019 contracts, we have hedged approximately 94% to 96% of our estimated 2019 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, 2019, we had a net liability derivative position of $8.3 million as compared to a net asset derivative position of $26.6 million as of March 31, 2018, 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 $129.5 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $129.1 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, 2019, we had $45.0 million in borrowings outstanding under our credit facility which bore interest at a weighted average rate of 3.99%. A 1.0% increase in the average interest rate for the three months ended March 31, 2019 would have resulted in an estimated $0.2 million increase in interest expense. As of March 31, 2019, 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, 2019, 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, 2019, our disclosure controls and procedures are effective.

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

PART II

ITEM 1. LEGAL PROCEEDINGS

In two separate complaints, one filed by the State of Louisiana and the Parish of Cameron in the 38th Judicial District Court for the Parish of Cameron on February 9, 2016 and the other filed by the State of Louisiana and the District Attorney for the 15th Judicial District of the State of Louisiana in the 15th Judicial District Court for the Parish of Vermilion 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 Vermilion 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 Vermilion 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 Vermilion 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 Vermilion Parish suit. Shortly after the Complaints were filed, certain defendants removed the cases to the United States District Court for the Western District of Louisiana. In both cases, the plaintiffs filed motions to remand the lawsuits to state court, which were ultimately granted by the district courts. However, on May 23, 2018, a group of defendants again removed the Cameron Parish and Vermilion Parish lawsuits to federal court. In response, the plaintiffs again filed motions to remand the cases to state court. The removing defendants have opposed plaintiffs' motions to remand. The motions to remand remain pending, and further action in the cases will be stayed until the courts rule on the motions to remand. Also, shortly after the May 23, 2018 removal, the removing defendants filed motions with the United States Judicial Panel on Multidistrict Litigation, or MDL Panel, requesting that the Cameron Parish and Vermilion Parish lawsuits be consolidated with 40 similar lawsuits so that pre-trial proceedings in the cases could be coordinated. The MDL Panel denied the motion to consolidate the lawsuits. Due to the procedural posture of lawsuits, the cases are still in their early stages and the parties have conducted very little discovery. As a result, 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, 2018.

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

Unregistered Sales of Equity Securities

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None.

Issuer Repurchases of Equity Securities

Our common stock repurchase activity for the three months ended March 31, 2019 was as follows:

Period	Total number of shares purchased (2)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs (2)	Approximate maximum dollar value of shares that may yet be purchased under the plans or programs (1)
January 2019	—	$ —	—	$400,000,000
February 2019	15,166	$ 7.76	—	$400,000,000
March 2019	3,603,468	$ 7.83	3,603,468	$371,788,000
Total	3,618,634	$ 7.83	3,603,468	

(1) In January 2019, our board of directors approved a new stock repurchase program to acquire up to $400 million of our outstanding common stock within a 24 month period. This repurchase program may be suspended from time to time, modified, extended or discontinued by our board of directors at any time.

(2) In February 2019, we repurchased and canceled

15,166 shares of our common stock at a weighted average price of $7.76 to satisfy tax withholding requirements incurred upon the vesting of restricted stock unit awards. Additionally, in March 2019, we repurchased and canceled approximately 3,603,468 shares under the repurchase program at a weighted average price of $7.83 per share.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

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Exhibit Number	Description
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).
3.3	Certificate of Amendment No. 2 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 23, 2013).
3.4	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
3.5	First Amendment to the Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 23, 2013).
3.6	Second Amendment to the Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company on May 2, 2014).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.5	Indenture, dated as of April 21, 2015, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of the Company's 6.625% Senior Notes due 2023) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 21, 2015).
4.6	Indenture, dated as of October 14, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of Gulfport Energy Corporation's 6.000% Senior Notes due 2024) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File. No. 000-19514, filed by the Company with the SEC on October 19, 2016).
4.7	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).
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.

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*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 3, 2019

GULFPORT ENERGY
CORPORATION

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