UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2019

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ______ to ______

Commission file number: 001-38602

Chaparral Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**73-1590941**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
701 Cedar Lake Boulevard Oklahoma City, Oklahoma	**73114**
(Address of principal executive offices)	**(Zip code)**

(405) 478-8770

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of class	Trading Symbol(s)	Name of each exchange on which registered
Class A common stock, par value, $0.01 per share	CHAP	The New York Stock Exchange

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

Indicate by check mark whether the registrant has submitted electronically, if any, every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

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

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

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

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☒ No ☐

Number of shares outstanding of each of the issuer's classes of common stock as of May 6, 2019:

Class	Number of Shares
Class A Common Stock, $0.01 par value	46,341,222

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CAUTIONARY NOTE

REGARDING FORWARD-LOOKING STATEMENTS

This report includes statements that constitute forward-looking statements within the meaning of the federal securities laws. These statements are subject to risks and uncertainties. These statements may relate to, but are not limited to, information or assumptions about us, our capital and other expenditures, dividends, financing plans, capital structure, cash flow, pending legal and regulatory proceedings and claims, including environmental matters, future economic performance, operating income, cost savings, and management's plans, strategies, goals and objectives for future operations and growth. These forward-looking statements generally are accompanied by words such as "intend," "anticipate," "believe," "estimate," "expect," "should," "seek," "project," "plan" or similar expressions. Any statement that is not a historical fact is a forward-looking statement. It should be understood that these forward-looking statements are necessarily estimates reflecting the best judgment of senior management, not guarantees of future performance. They are subject to a number of assumptions, risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the forward-looking statements. Forward-looking statements in this report may include, for example, statements about:

- fluctuations in demand or the prices received for oil and natural gas;
- the amount, nature and timing of capital expenditures;
- drilling, completion and performance of wells;
- competition;
- government regulations;
- timing and amount of future production of oil and natural gas;
- costs of exploiting and developing properties and conducting other operations, in the aggregate and on a per-unit equivalent basis;
- changes in proved reserves;
- operating costs and other expenses;
- our future financial condition, results of operations, revenue, cash flows and expenses;
- estimates of proved reserves;
- exploitation of property acquisitions; and
- marketing of oil and natural gas.

These forward-looking statements represent intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors. Many of those factors are outside of our control and could cause actual results to differ materially from the results expressed or implied by those forward-looking statements. In addition to the risk factors described in Part II, Item 1A. Risk Factors, of this report and Part I, Item 1A. Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2018, the risks and uncertainties include or relate to:

- worldwide supply of and demand for oil and natural gas;
- volatility and declines in oil and natural gas prices;
- drilling plans (including scheduled and budgeted wells);
- the number, timing or results of any wells;
- changes in wells operated and in reserve estimates;
- future growth and expansion;
- future exploration;
- integration of existing and new technologies into operations;
- future capital expenditures (or funding thereof) and working capital;
- effectiveness and extent to our risk management activities;
- availability and cost of equipment;
- risks related to the concentration of our operations in the mid-continent geographic area;
- borrowings and capital resources and liquidity;
- covenant compliance under instruments governing any of our existing or future indebtedness;
- changes in strategy and business discipline, including our post-emergence business strategy;
- future tax matters;
- legislation and regulatory initiatives;
- loss of key personnel;
- geopolitical events affecting oil and natural gas prices;
- outcome, effects or timing of legal proceedings (including environmental litigation);
- the ability to generate additional prospects; and

- the ability to successfully complete merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions may change the schedule of any future production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of these risks or uncertainties materialize, or should any of our assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements contained herein. We undertake no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required under applicable securities laws. All forward-looking statements included herein are expressly qualified in their entirety by the cautionary statements contained or referred to in this section.

GLOSSARY OF CERTAIN DEFINED TERMS

The terms defined in this section are used throughout this Form 10-Q:

Basin	A low region or natural depression in the earth's crust where sedimentary deposits accumulate.
Bbl	One stock tank barrel of 42 U.S. gallons liquid volume used herein in reference to crude oil, condensate, or natural gas liquids.
BBtu	One billion British thermal units.
Boe	Barrels of oil equivalent using the ratio of six thousand cubic feet of natural gas to one barrel of oil.
Boe/d	Barrels of oil equivalent per day.
Btu	British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.
Completion	The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.
CO_2	Carbon dioxide.
Credit Facility	Tenth Restated Credit Agreement, as amended, by and among Chaparral Energy, Inc., Royal Bank of Canada as Administrative Agent and the Lenders thereto.
Dry well or dry hole	An exploratory, development or extension well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.
Effective Date	Date of emergence from bankruptcy, or March 21, 2017.
Enhanced oil recovery (EOR)	The use of any improved recovery method, including injection of CO_2 or polymer, to remove additional oil after Secondary Recovery.
EOR Areas	Areas where we previously injected and/or recycled CO_2 as a means of oil recovery which were divested in November 2017.
Field	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.
MBbls	One thousand barrels of crude oil, condensate, or natural gas liquids.
MBoe	One thousand barrels of crude oil equivalent.
Mcf	One thousand cubic feet of natural gas.
MMBtu	One million British thermal units.
MMcf	One million cubic feet of natural gas.
Natural gas liquids (NGLs)	Those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, or other methods in gas processing or cycling plants. Natural gas liquids primarily include propane, butane, isobutane, pentane, hexane and natural gasoline.
NYMEX	The New York Mercantile Exchange.

Play	A term describing an area of land following the identification by geologists and geophysicists of reservoirs with potential oil and natural gas reserves.
Prior Senior Notes	Collectively, our 9.875% senior notes due 2020, 8.25% senior notes due 2021, and 7.625% senior notes due 2022, of which all obligations were discharged upon consummation of our Reorganization Plan.
Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, or in which the cost of the required equipment is relatively minor compared to the cost of a new well.
Proved reserves	The quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.
Proved undeveloped reserves	Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.
PV-10 value	When used with respect to oil and natural gas reserves, PV-10 value means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, excluding escalations of prices and costs based upon future conditions, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10%.
Reorganization Plan	First Amended Joint Plan of Reorganization for Chaparral Energy, Inc. and its Affiliate Debtors under Chapter 11 of the Bankruptcy Code.
SEC	The Securities and Exchange Commission.
Senior Notes	Our 8.75% senior notes due 2023.
STACK	An acronym standing for Sooner Trend Anadarko Canadian Kingfisher. A play in the Anadarko Basin of Oklahoma in which we operate.
Unit	The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

PART I — FINANCIAL INFORMATION

ITEM 1. *FINANCIAL STATEMENTS*

Chaparral Energy, Inc. and Subsidiaries
Consolidated Balance Sheets
(Unaudited)

(dollars in thousands, except share data)	March 31, 2019	December 31, 2018
Assets		
Current assets:		
Cash and cash equivalents	$ 11,118	$ 37,446
Accounts receivable, net	62,652	66,087
Inventories, net	3,923	4,059
Prepaid expenses	2,593	2,814
Derivative instruments	—	24,025
Total current assets	80,286	134,431
Property and equipment, net	42,558	43,096
Right of use assets from operating leases	12,064	—
Oil and natural gas properties, using the full cost method:		
Proved	976,025	915,333
Unevaluated (excluded from the amortization base)	484,021	466,616
Accumulated depreciation, depletion, amortization and impairment	(292,679)	(221,431)
Total oil and natural gas properties	1,167,367	1,160,518
Derivative instruments	—	2,199
Other assets	389	425
Total assets	$ 1,302,664	$ 1,340,669
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 97,404	$ 73,779
Accrued payroll and benefits payable	6,420	10,976
Accrued interest payable	5,934	13,359
Revenue distribution payable	20,714	26,225
Long-term debt and financing leases, classified as current	11,854	12,371
Derivative instruments	10,874	—
Total current liabilities	153,200	136,710
Long-term debt and financing leases, less current maturities	326,198	295,100
Derivative instruments	15,976	1,542
Noncurrent operating lease obligations	2,307	—
Deferred compensation	628	540
Asset retirement obligations	22,248	22,090
Commitments and contingencies (Note 10)		
Stockholders' equity:		
Preferred stock, 5,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $0.01 par value, 192,130,071 shares authorized; 46,648,581 issued and 46,307,056 outstanding at March 31, 2019 and 46,651,616 issued and 46,390,513 outstanding at December 31, 2018	467	467
Additional paid in capital	976,039	974,616
Treasury stock, at cost, 341,525 and 261,103 shares as of March 31, 2019 and December 31, 2018	(5,399)	(4,936)
Accumulated deficit	(189,000)	(85,460)
Total stockholders' equity	782,107	884,687
Total liabilities and stockholders' equity	$ 1,302,664	$ 1,340,669

The accompanying notes are an integral part of these consolidated financial statements.

Chaparral Energy, Inc. and Subsidiaries
Consolidated Statements of Operations
(Unaudited)

	Three months ended	
(in thousands, except share and per share data)	**March 31, 2019**	**March 31, 2018**
Revenues:		
Net commodity sales	$ 48,619	$ 57,889
Sublease revenue	1,198	1,198
Total revenues	49,817	59,087
Costs and expenses:		
Lease operating	12,294	14,543
Production taxes	2,880	2,677
Depreciation, depletion and amortization	23,715	21,106
Impairment of oil and gas assets	49,722	—
General and administrative	8,313	11,507
Other	403	828
Total costs and expenses	97,327	50,661
Operating (loss) income	(47,510)	8,426
Non-operating income (expense):		
Interest expense	(4,564)	(1,371)
Derivative losses	(51,016)	(16,501)
Loss on sale of assets	(1)	(1,044)
Other income, net	14	85
Net non-operating expense	(55,567)	(18,831)
Reorganization items, net	(463)	(1,037)
Loss before income taxes	(103,540)	(11,442)
Income tax expense	—	—
Net loss	$ (103,540)	$ (11,442)
Earnings per share:		
Basic for Class A and Class B (1)	(2.28)	(0.25)
Diluted for Class A and Class B (1)	(2.28)	(0.25)
Weighted average shares used to compute earnings per share:		
Basic for Class A and Class B (1)	45,456,214	45,143,297
Diluted for Class A and Class B (1)	45,456,214	45,143,297

(1) See "Note 2—Earnings per share."

The accompanying notes are an integral part of these consolidated financial statements.

Chaparral Energy, Inc. and Subsidiaries
Consolidated Statement of Stockholders' Equity
(Unaudited)

	Common stock										
(dollars in thousands)	**Shares outstanding**		**Amount**		**Additional paid in capital**		**Treasury stock**		**Accumulated deficit**		**Total**
As of December 31, 2017	46,827,762	$	468	$	961,200	$	—	$	(118,902)	$	842,766
Stock-based compensation	—		—		5,581		—		—		5,581
Restricted stock forfeited	(83,770)		(1)		—		—		—		(1)
Repurchase of common stock	(63,919)		—		—		(1,422)		—		(1,422)
Net loss	—		—		—		—		(11,442)		(11,442)
Balance at March 31, 2018	46,680,073	$	467	$	966,781	$	(1,422)	$	(130,344)	$	835,482

	Common stock										
(dollars in thousands)	**Shares outstanding**		**Amount**		**Additional paid in capital**		**Treasury stock**		**Accumulated deficit**		**Total**
As of December 31, 2018	46,390,513	$	467	$	974,616	$	(4,936)	$	(85,460)	$	884,687
Stock-based compensation	94,078		1		1,423		—		—		1,424
Restricted stock forfeited	(97,113)		(1)		—		—		—		(1)
Repurchase of common stock	(80,422)		—		—		(463)		—		(463)
Net loss	—		—		—		—		(103,540)		(103,540)
Balance at March 31, 2019	46,307,056	$	467	$	976,039	$	(5,399)	$	(189,000)	$	782,107

The accompanying notes are an integral part of these consolidated financial statements.

Chaparral Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows
(Unaudited)

(in thousands)	**Three months ended March 31, 2019**	**Three months ended March 31, 2018**
Cash flows from operating activities		
Net loss	$ (103,540)	$ (11,442)
Adjustments to reconcile net loss to net cash provided by operating activities		
Depreciation, depletion and amortization	23,715	21,106
Derivative losses	51,016	16,501
Impairment of oil and gas assets	49,722	—
Loss on sale of assets	1	1,044
Other	542	1,630
Change in assets and liabilities		
Accounts receivable	7,910	(12,140)
Inventories	207	(3,168)
Prepaid expenses and other assets	256	(179)
Accounts payable and accrued liabilities	(16,689)	(9,828)
Revenue distribution payable	(5,511)	2,151
Deferred compensation	925	4,701
Net cash provided by operating activities	8,554	10,376
Cash flows from investing activities		
Expenditures for property, plant, and equipment and oil and natural gas properties	(64,044)	(99,941)
Proceeds from asset dispositions	—	73
Proceeds from (payments on) derivative instruments, net	515	(4,244)
Net cash used in investing activities	(63,529)	(104,112)
Cash flows from financing activities		
Proceeds from long-term debt	30,000	79,000
Repayment of long-term debt	(171)	(146)
Principal payments under financing lease obligations	(699)	(661)
Payment of debt issuance costs and other financing fees	(20)	—
Treasury stock purchased	(463)	—
Net cash provided by financing activities	28,647	78,193
Net decrease in cash, cash equivalents, and restricted cash	(26,328)	(15,543)
Cash, cash equivalents, and restricted cash at beginning of period	37,446	27,732
Cash, cash equivalents, and restricted cash at end of period	$ 11,118	$ 12,189

The accompanying notes are an integral part of these consolidated financial statements.

(dollars in thousands, except per share amounts)

Note 1: Nature of operations and summary of significant accounting policies

Nature of operations

Chaparral Energy, Inc. and its subsidiaries (collectively, "we", "our", "us", or the "Company") are involved in the acquisition, exploration, development, production and operation of oil and natural gas properties. Our properties are located primarily in Oklahoma and our commodity products include crude oil, natural gas and natural gas liquids.

Interim financial statements

The accompanying unaudited consolidated interim financial statements of the Company have been prepared in accordance with the rules and regulations of the SEC and do not include all of the financial information and disclosures required by accounting principles generally accepted in the United States of America ("GAAP") for complete financial statements. These financial statements and the notes thereto should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2018, as amended.

The financial information as of March 31, 2019, and for the three months ended March 31, 2019 and 2018, is unaudited. The financial information as of December 31, 2018 has been derived from the audited financial statements contained in our Annual Report on Form 10-K for the year ended December 31, 2018. In management's opinion, such information contains all adjustments considered necessary for a fair presentation of the results of the interim periods. The results of operations for the three months ended March 31, 2019 are not necessarily indicative of the results of operations that will be realized for the year ended December 31, 2019.

Certain reclassifications have been made to prior period financial statements to conform to current period presentation. The reclassifications had no effect on our previously reported results of operations.

Cash and cash equivalents

We maintain cash and cash equivalents in bank deposit accounts and money market funds which may not be federally insured. As of March 31, 2019, cash with a recorded balance totaling approximately $9,127 was held at JP Morgan Chase Bank, N.A. We have not experienced any losses in such accounts and believe we are not exposed to any significant credit risk on such accounts.

Accounts receivable

We have receivables from joint interest owners and oil and natural gas purchasers which are generally uncollateralized. Accounts receivable consisted of the following:

	March 31, 2019	December 31, 2018
Joint interests	$ 37,640	$ 31,573
Accrued commodity sales	23,165	30,287
Derivative settlements	1,056	2,092
Other	1,793	3,375
Allowance for doubtful accounts	(1,002)	(1,240)
	$ 62,652	$ 66,087

Inventories

Inventories consisted of the following:

	March 31, 2019	December 31, 2018
Equipment inventory	$ 3,570	$ 3,663
Commodities	531	574
Inventory valuation allowance	(178)	(178)
	$ 3,923	$ 4,059

(dollars in thousands, except per share amounts)

Property and equipment, net

Major classes of property and equipment are shown in the following table:

	March 31, 2019	December 31, 2018
Furniture and fixtures	$ 520	$ 520
Automobiles and trucks	4,333	3,548
Machinery and equipment	21,714	21,482
Office and computer equipment	6,417	6,183
Building and improvements	18,738	18,693
	51,722	50,426
Less accumulated depreciation and amortization	14,283	12,449
	37,439	37,977
Land	5,119	5,119
	$ 42,558	$ 43,096

Oil and natural gas properties

Capitalized Costs. We use the full cost method of accounting for oil and natural gas properties and activities. Accordingly, we capitalize all costs incurred in connection with the exploration for and development of oil and natural gas reserves. Proceeds from the disposition of oil and natural gas properties are accounted for as a reduction in capitalized costs, with no gain or loss generally recognized unless such dispositions involve a significant alteration in the depletion rate. We capitalize internal costs that can be directly identified with exploration and development activities, but do not include any costs related to production, general corporate overhead or similar activities. Capitalized costs include geological and geophysical work, 3D seismic, delay rentals, drilling and completing and equipping oil and natural gas wells, including salaries, benefits, and other internal costs directly attributable to these activities.

Costs associated with unevaluated oil and natural gas properties are excluded from the amortizable base until a determination has been made as to the existence of proved reserves. Unevaluated leasehold costs are transferred to the amortization base with the costs of drilling the related well upon proving up reserves of a successful well or upon determination of a dry or uneconomic well under a process that is conducted each quarter. Furthermore, unevaluated oil and natural gas properties are reviewed for impairment if events and circumstances exist that indicate a possible decline in the recoverability of the carrying amount of such property. The impairment assessment is conducted at least once annually and whenever there are indicators that impairment has occurred. In assessing whether impairment has occurred, we consider factors such as intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; assignment of proved reserves; and economic viability of development if proved reserves are assigned. Upon determination of impairment, all or a portion of the associated leasehold costs are transferred to the full cost pool and become subject to amortization. The processes above are applied to unevaluated oil and natural gas properties on an individual basis or as a group if properties are individually insignificant. Our future depreciation, depletion and amortization rate would increase if costs are transferred to the amortization base without any associated reserves.

In the past, the costs associated with unevaluated properties typically related to acquisition costs of unproved acreage. As a result of the application of fresh start accounting on the Effective Date, a substantial portion of the carrying value of our unevaluated properties are the result of a fair value increase to reflect the value of our acreage in our STACK play.

The costs of unevaluated oil and natural gas properties consisted of the following:

	March 31, 2019	December 31, 2018
Leasehold acreage	$ 419,413	$ 427,206
Capitalized interest	13,938	11,377
Wells and facilities in progress of completion	50,670	28,033
Total unevaluated oil and natural gas properties excluded from amortization	$ 484,021	$ 466,616

Ceiling Test. In accordance with the full cost method of accounting, the net capitalized costs of oil and natural gas properties are not to exceed their related PV-10 value, net of tax considerations, plus the cost of unproved properties not being amortized.

(dollars in thousands, except per share amounts)

Our estimates of oil and natural gas reserves as of March 31, 2019, and the related PV-10 value, were prepared using an average price for oil and natural gas on the first day of each month for the prior twelve months as required by the SEC. We recorded a ceiling test write-down to our oil and natural gas properties of $49,722 for the three months ended March 31, 2019. We recorded no impairments for the three months ended March 31, 2018. The 2019 loss is reflected in “Impairment of oil and gas assets” in our consolidated statements of operations.

Producer imbalances. We account for natural gas production imbalances using the sales method, whereby we recognize revenue on all natural gas sold to our customers regardless of our proportionate working interest in a well. Liabilities are recorded for imbalances greater than our proportionate share of remaining estimated natural gas reserves. Our aggregate imbalance positions at March 31, 2019, and December 31, 2018, were immaterial.

Revenue recognition

In May 2014, the Financial Accounting Standards Board ("FASB") issued authoritative guidance that supersedes previous revenue recognition requirements which has been codified as Accounting Standards Codification 606: Revenue from Contracts with Customers (“ASC 606”). ASC 606 requires entities to recognize revenue in a way that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services.

The following table displays the revenue disaggregated and reconciles the disaggregated revenue to the revenue reported:

	Three months ended March 31,	
	2019	**2018**
Revenues:		
Oil	$ 32,802	$ 43,050
Natural gas	11,206	8,736
Natural gas liquids	9,217	9,591
Gross commodity sales	53,225	61,377
Transportation and processing	(4,606)	(3,488)
Net commodity sales	$ 48,619	$ 57,889

Please see “Note 16—Revenue recognition” in Item 8. Financial Statements and Supplementary Data of our Annual Report on Form 10-K for the year ended December 31, 2018, for a discussion of our revenue recognition policy including a description of products and revenue disaggregation criteria, performance obligations, pricing , measurement and contract assets and liabilities.

Income taxes

The provision for income taxes is based on a current estimate of the annual effective income tax rate adjusted to reflect the impact of permanent differences and discrete items. Significant management judgment is required in estimating operating income in order to determine our effective income tax rate. Our effective income tax rate was 0% and 0% for the three months ended March 31, 2019 and 2018, respectively. The consistent effective tax rate for the three months ended March 31, 2019 is a result of maintaining a valuation allowance against substantially all of our net deferred tax asset.

Despite the Company’s net loss for the three month period ended March 31, 2019, we did not record any net deferred tax benefit, as any deferred tax asset arising from the benefit is reduced by a valuation allowance as utilization of the loss carryforwards and realization of other deferred tax assets cannot be reasonably assured.

A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. To assess that likelihood, we use estimates and judgment regarding our future taxable income, as well as the jurisdiction in which such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include our current financial position, our results of operations, both actual and forecasted, the reversal of deferred tax liabilities, and tax planning strategies as well as the current and forecasted business economics of our industry.

(dollars in thousands, except per share amounts)

We will continue to evaluate whether the valuation allowance is needed in future reporting periods. The valuation allowance will remain until we can determine that the net deferred tax assets are more likely than not to be realized. Future events or new evidence which may lead us to conclude that it is more likely than not that our net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings, improvements in oil prices, and taxable events that could result from one or more transactions. The valuation allowance does not prevent future utilization of the tax attributes if we recognize taxable income. As long as we conclude that the valuation allowance against our net deferred tax asset is necessary, we likely will not have any additional deferred income tax expense or benefit.

The benefit of an uncertain tax position taken, or expected to be taken, on an income tax return is recognized in the consolidated financial statements at the largest amount that is more likely than not to be sustained upon examination by the relevant taxing authority. Interest and penalties, if any, related to uncertain tax positions would be recorded in interest expense and other expense, respectively. There were no uncertain tax positions at March 31, 2019, or December 31, 2018.

As a result of the Chapter 11 reorganization and related transactions, the Company experienced an ownership change within the meaning of Internal Revenue Code of 1986, as amended ("IRC") Section 382 on March 21, 2017. This ownership change subjected certain of the Company's tax attributes, including $760,067 of federal net operating loss carryforwards, to an IRC Section 382 limitation. This limitation has not resulted in a current tax liability for the three month period ended March 31, 2019, or any intervening period since March 21, 2017.

Other expense

Other expense consisted of the following:

	Three months ended March 31,	
	2019	**2018**
Restructuring	$ —	$ 425
Subleases	403	403
Total other expense	$ 403	$ 828

Restructuring. We previously incurred exit costs in conjunction with our EOR asset divestiture, which are predominantly comprised of one-time severance and termination benefits for the affected employees. The expense recorded in 2018 is a result of termination benefits for the final slate of employees terminated as a result of the divestiture.

Subleases. Our subleases are comprised of CO_2 compressors that were previously utilized in our EOR operations and leased as both financing and operating leases from U.S. Bank but are now subleased to the purchaser of our EOR assets (the "Sublessee"). Minimum payments under the subleases are equal to the original leases and as such we did not record any losses upon initiation of the subleases. Prior to the asset sale, the financing leases were included in our full cost amortization base and hence subject to amortization on a units-of-production basis, while also incurring interest expense. The payments under our operating leases were previously recorded as "Lease operating" expense on our statement of operations. Based on the facts and circumstances relating to our original leases and the current subleases, we determined that all the subleases were to be classified as operating leases from a lessor's standpoint. Subsequent to the execution of the subleases in November 2017, all payments received from the Sublessee are reflected as "Sublease revenue" on our statement of operations. Minimum payments we make to U.S. Bank on the original operating leases are reflected as "Other" expense on our statement of operations. With respect to the financing leases, upon executing the subleases, we reclassified the amount associated with these leases from the full cost amortization base to "Property and equipment, net" on our balance sheet and have amortized the asset on a straight line basis prospectively. We will continue incurring interest expense on the financing leases. Please see "Note 5— Leases" for our disclosure on leases.

(dollars in thousands, except per share amounts)

Joint development agreement

On September 25, 2017, we entered into a joint development agreement ("JDA") with BCE Roadrunner LLC, a wholly-owned subsidiary of Bayou City Energy Management, LLC ("BCE"), pursuant to which BCE will fund 100 percent of our drilling, completion and equipping costs associated with 30 joint venture STACK wells, subject to average well cost caps that vary by well-type across location and targeted formations, approximately between $3,400 and $4,000 per gross well. The JDA wells, which will be drilled and operated by us, include 17 wells in Canadian County and 13 wells in Garfield County. The JDA provides us with a means to accelerate the delineation of our position within our Garfield and Canadian County acreage, realizing further efficiencies and holding additional acreage by production, and potentially adding reserves. In exchange for funding, BCE will receive wellbore-only interest in each well totaling an 85% carve-out working interest from our original working interest (and we retain 15%) until the program reaches a 14% internal rate of return. Once achieved, ownership interest in all JDA wells will revert such that we will own a 75% working interest and BCE will retain a 25% working interest. We will retain all acreage and reserves outside of the wellbore, with both parties entitled to revenues and paying lease operating expenses based on their working interest.

Our drilling and completion costs to date have been exceeding well cost caps specified under the JDA primarily due to inflation in the cost of oilfield services as a result of the rebound in industry conditions. In our negotiation with BCE to cover the inflationary cost increases, BCE had indicated willingness to increase the per well cost caps on remaining wells in exchange for adding more wells to the current program. Since we have achieved our goals to utilize the JDA as a means to delineate our acreage Garfield and Canadian counties, Oklahoma, we do not currently plan for any expansion of the JDA. For the three months ended March 31, 2019, we have therefore recorded additions to oil and natural gas properties of $3,182 in drilling and completion costs on JDA wells that have exceeded the well cost caps specified under the JDA.

Reorganization items

Reorganization items reflect, where applicable, expenses, gains and losses incurred that are incremental and a direct result of the reorganization of the business. As a result of our emergence from bankruptcy in March 2017, we have also recorded gains on the settlement of liabilities subject to compromise and gains from restating our balance sheet to fair values under fresh start accounting. "Professional fees" in the table below for periods subsequent to the emergence from bankruptcy are comprised of legal fees for continuing work to resolve outstanding bankruptcy claims and fees to the U.S. Bankruptcy Trustee, which we will continue to incur until our bankruptcy case is closed. Reorganization items are as follows:

	Three months ended March 31,	
	2019	**2018**
Loss (gain) on the settlement of liabilities subject to compromise	$ —	$ 48
Professional fees	463	989
Total reorganization items	$ 463	$ 1,037

Recently adopted accounting pronouncements

In February 2016, the FASB issued authoritative guidance that supersedes previous lease recognition requirements and requires entities to recognize leases on-balance sheet and disclose key information about leasing arrangements. Please see "Note 5—Leases" for our disclosure regarding adoption of this update.

Recently issued accounting pronouncements

In June 2016, the FASB issued authoritative guidance which modifies the measurement of expected credit losses of certain financial instruments. The guidance is effective for fiscal years beginning after December 15, 2020, however early adoption is permitted for fiscal years beginning after December 15, 2018. The updated guidance impacts our financial statements primarily due to its effect on our accounts receivables. Our history of accounts receivable credit losses almost entirely relates to receivables from joint interest owners in our operated oil and natural gas wells. Based on this history and on mitigating actions, we are permitted to take to offset potential losses such as netting past due amounts against revenue and assuming title to the working interest. We do not expect this guidance to materially impact our financial statements or results of operations.

Note 2: Earnings per share

Although we previously had both Class A and Class B common stock outstanding, where both classes of common stock shared equally in voting power, dividends and undistributed earnings, on December 19, 2018, all outstanding shares of our Class B common stock converted into the same number of shares of Class A common stock.

A reconciliation of the components of basic and diluted EPS is presented below:

	Three months ended March 31,	
(in thousands, except share and per share data)	**2019**	**2018**
Numerator for basic and diluted earnings per share		
Net loss	$ (103,540)	$ (11,442)
Denominator for basic earnings per share		
Weighted average common shares - Basic for Class A and Class B (1)	45,456,214	45,143,297
Denominator for diluted earnings per share		
Weighted average common shares - Diluted for Class A and Class B (1)	45,456,214	45,143,297
Earnings per share		
Basic for Class A and Class B (1)	$ (2.28)	$ (0.25)
Diluted for Class A and Class B (1)	$ (2.28)	$ (0.25)
Participating securities excluded from earnings per share calculations		
Warrants (2)	—	140,023
Unvested restricted stock awards	886,482	1,589,332

(1) Effective December 19, 2018, all our outstanding Class B shares were converted to Class A shares and subsequently, all our outstanding common stock was comprised only of Class A common stock. Earnings per share for the three months ended March 31, 2018 reflects earnings per share for Class A and Class B common stock in aggregate whereas earnings per share for the three months ended March 31, 2019 reflects earnings per share for Class A common stock.

(2) The warrants to purchase shares of our Class A common stock are antidilutive for three months ended March 31, 2018, due to the exercise price exceeding the average price of our Class A shares and due to the net loss we incurred. These warrants expired on June 30, 2018.

Note 3: Supplemental disclosures to the consolidated statements of cash flows

	Three months ended March 31,	
	2019	**2018**
Net cash provided by operating activities included:		
Cash payments for interest	$ 14,681	$ 2,206
Interest capitalized	(3,492)	(1,521)
Cash payments for reorganization items	394	410
Non-cash investing activities included:		
Asset retirement obligation additions and revisions	76	213
Leasing right of use asset additions (see Note 5 - Leases)	670	—
Change in accrued oil and gas capital expenditures	15,174	705

(dollars in thousands, except per share amounts)

Note 4: Debt

As of the dates indicated, long-term debt and financing leases consisted of the following:

	March 31, 2019	December 31, 2018
8.75% Senior Notes due 2023	$ 300,000	$ 300,000
Credit Facility	30,000	—
Real estate mortgage note	8,433	8,588
Installment note payable	337	354
Financing lease obligations	11,648	11,677
Unamortized debt issuance costs	(12,366)	(13,148)
Total debt, net	338,052	307,471
Less current portion	11,854	12,371
Total long-term debt, net	$ 326,198	$ 295,100

Credit Facility

The Credit Facility is a $750,000 facility collateralized by our oil and natural gas properties and is scheduled to mature on December 21, 2022. Availability under our Credit Facility is subject to a borrowing base based on the value of our oil and natural gas properties and set by the banks semi-annually on or around May 1 and November 1 of each year. Our borrowing base under the Credit Facility as of March 31, 2019, was $325,000 with the unused portion, after taking into account letters of credit and outstanding borrowings, amounting to $294,131. Availability on the Credit Facility as of March 31, 2019, was $153,956. Our availability was lower than the unused borrowing base capacity as a result of the constraints placed by the Ratio of Total Debt to EBITDAX covenant discussed below.

As of March 31, 2019, our outstanding borrowings were accruing interest at the Adjusted LIBO Rate (as defined in the Credit Facility), plus the Applicable Margin (as defined in the Credit Facility), which resulted in a weighted average interest rate of 4.49%.

The Credit Facility contains financial covenants that require, for each fiscal quarter, we maintain: (1) a Current Ratio (as defined in the Credit Facility) of no less than 1.00 to 1.00, and (2) a Ratio of Total Debt to EBITDAX (as defined in the Credit Facility) of no greater than 4.0 to 1.0 calculated on a trailing four-quarter basis. We were in compliance with these financial covenants as of March 31, 2019.

The Credit Facility contains covenants and events of default customary for oil and natural gas reserve-based lending facilities. Please see “Note 8—Debt” in Item 8. Financial Statements and Supplementary Data of our Annual Report on Form 10-K for the year ended December 31, 2018, for a discussion of the material provisions of our Credit Facility.

On May 2, 2019, we entered into the Third Amendment to the Tenth Restated Credit Agreement, among the Company and its subsidiaries, as borrowers, certain financial institutions party thereto, as lenders, and Royal Bank of Canada, as administrative agent (the “Third Amendment”). The Third Amendment, which was effective March 31, 2019, reaffirmed our borrowing base at the same level as it was at the beginning of 2019, at $325,000.

Senior Notes

On June 29, 2018, we completed the issuance and sale at par of $300,000 in aggregate principal amount of our Senior Notes in a private placement under Rule 144A and Regulation S of the Securities Act of 1933, as amended. The Senior Notes bear interest at a rate of 8.75% per year beginning June 29, 2018 (payable semi-annually in arrears on January 15 and July 15 of each year, beginning on January 15, 2019) and will mature on July 15, 2023.

The Senior Notes are the Company’s senior unsecured obligations and rank equal in right of payment with all of the Company’s existing and future senior indebtedness, senior to all of the Company’s existing and future subordinated indebtedness and effectively subordinated to all of the Company’s existing and future secured indebtedness, to the extent of the value of the collateral securing such indebtedness.

The Senior Notes contain customary covenants, certain callable provisions and events of default. Please see “Note 8—Debt” in Item 8. Financial Statements and Supplementary Data of our Annual Report on Form 10-K for the year ended December 31, 2018, for a discussion of the material provisions of our Senior Notes.

Note 5: Leases

In February 2016, the FASB established Accounting Standards Codification ("ASC") Topic 842, Leases (“ASC 842”) which requires lessees to recognize leases on-balance sheet and disclose key information about leasing arrangements. ASC 842 was subsequently amended by Accounting Standards Update (“ASU”) No. 2018-01, Land Easement Practical Expedient for Transition to Topic 842; ASU No. 2018-10, Codification Improvements to Topic 842, Leases; and ASU No. 2018-11, Targeted Improvements. The new standard establishes a right-of-use ("ROU") model that requires a lessee to recognize a ROU asset and lease liability on the balance sheet for all leases except those with a term of 12 months or less. Leases will be classified as finance or operating, with classification affecting the pattern and classification of expense recognition in the income statement. We adopted the new standard on its effective date of January 1, 2019, which is also our date of initial application. Consequently, we have not updated financial information nor provided disclosures required under the new standard for dates and periods before January 1, 2019. Our disclosures for dates and periods before January 1, 2019, are provided in accordance with the requirements of ASC Topic 840, Leases (“ASC 840”).

We have elected the package of transition practical expedients, which permits us not to reassess under the new standard our prior conclusions about lease identification, lease classification and initial direct costs. Upon adoption of ASC 842, we carried over our existing capital lease obligations (now “financing leases” under ASC 842) and capital lease asset (now “right of use asset” under ASC 842) at their previous carrying value.

Financing leases

In 2013, we entered into lease financing agreements with U.S. Bank for $24,500 through the sale and subsequent leaseback of existing CO_2 compressors owned by us. The lease financing obligations are for terms of 84 months and include the option to purchase the equipment for a specified price at 72 months as well as an option to purchase the equipment at the end of the lease term for its then-current fair market value. There are no residual value guarantees and nonlease components under these leases. At the inception of the lease, our measurement of the lease liability assumed that the mid-term purchase option would be exercised. Since the lease contract has not been modified and there have been no triggering events subsequent to our adoption of ASC 842, we have not performed any reassessment of the lease. Lease payments related to the equipment are recognized as principal and interest expense based on a weighted average implicit interest rate of 3.8%. Minimum lease payments are approximately $3,181 annually. In conjunction with the sale of our EOR assets, these compressors were subleased to the buyer of those assets although we remain the primary obligor in relation to U.S. Bank.

During 2019, we entered into lease financing agreements for our fleet trucks for $670. We intend to add additional vehicles throughout 2019 under the same fleet leasing arrangement. The lease financing obligations are for 48-month terms with the option for us to purchase the vehicle at any time during the lease term by paying the lessor's remaining unamortized cost in the vehicle. At the end of the lease term, the lessor's remaining unamortized cost in the vehicle will be a de minimis amount and hence ownership of the vehicle can be transferred to us at minimal cost. There are no residual value guarantees and nonlease components under these leases.

Operating leases

We also have operating leases for CO_2 compressors previously deployed in our EOR operations. The operating lease obligations, which we entered into in 2014 and 2016, are for terms of 84 months without any specified purchase options. There are no residual value guarantees and nonlease components under these leases. In conjunction with the sale of our EOR assets in November 2017, these compressors were subleased to the buyer of those assets although we remain the primary obligor in relation to U.S. Bank.

During the fourth quarter of 2018, we entered into 15-month leasing arrangements for two drilling rigs. These agreements specify a minimum daily rate on the rigs for which we utilize to measure the lease liability upon adoption of ASC 842. The actual daily rate may vary from the minimum rate depending on whether the rig is being mobilized, demobilized, engaged in drilling or on standby. We record the difference between the actual daily rate and the minimum rate as a variable lease cost. The daily rate includes a non-lease labor component for which we have elected not to separate from the lease component.

(dollars in thousands, except per share amounts)

Short term leases

Our short term leases are those with lease terms of 12 months of less and are generally comprised of wellhead compressors and generators with terms ranging from one month to six months.

We have also leased drilling rigs for short durations which, in the past, may have been on a well-by-well basis or for terms up to six months. As of March 31, 2019, we have one drilling rig with one month remaining on a four month lease term.

Subleases

As discussed above, our subleases are comprised of CO_2 compressors that were previously utilized in our EOR operations and leased as both financing and operating leases from U.S. Bank but are now subleased to the purchaser of our EOR assets (the “Sublessee”). Minimum payments under the subleases are equal to the original leases and as such we did not record any losses upon initiation of the subleases. Prior to the asset sale, the financing leases were included in our full cost amortization base and as such subject to amortization on a units-of-production basis, while also incurring interest expense. The payments under our operating leases were previously recorded as “Lease operating” expense on our statement of operations. Based on the facts and circumstances relating to our original leases and the current subleases, we determined that all the subleases were to be classified as operating leases from a lessor’s standpoint. Subsequent to the execution of the subleases in November 2017, all payments received from the Sublessee are reflected as “Sublease revenue” on our statement of operations. Minimum payments we make to U.S. Bank on the original operating leases are reflected as “Other” expense on our statement of operations. With respect to the financing leases, upon executing the subleases, we reclassified the amount associated with these leases from the full cost amortization base to “Property and equipment, net” on our balance sheet and have amortized the asset on a straight line basis prospectively. We will continue incurring interest expense on the financing leases.

Lease assets and liabilities

Our operating lease and financing lease assets and liabilities are recorded on our balance sheet as of March 31, 2019 as follows:

	As of March 31, 2019	
	Operating leases	Financing leases
Right of use asset:		
Right of use assets from operating leases	$ 12,064	$ —
Plant, property and equipment, net (1)	—	11,488
Total lease assets	$ 12,064	$ 11,488
Lease liability:		
Account payable and accrued liabilities	$ 9,757	$ —
Long-term debt and financing leases, classified as current	—	11,152
Long-term debt and financing leases, less current maturities	—	496
Noncurrent operating lease obligations	2,307	—
Total lease liabilities	$ 12,064	$ 11,648

(1) CO_2 compressors included in Machinery and equipment and fleet vehicles included in automobiles and trucks. See “Note 1—Nature of operations and summary of significant accounting policies.”

(dollars in thousands, except per share amounts)

Our income, expenses and cash flows related to our leases is as follows for the three months ended March 31, 2019:

	Three months ended March 31, 2019
Lease cost	
Finance lease cost:	
Amortization of right-of-use assets	$ 693
Interest on lease liabilities	113
Operating lease cost	308
Short-term lease cost	129
Variable lease cost	95
Sublease income	(1,198)
Total lease cost	$ 140
Capitalized operating lease cost (1)	$ 3,335
Other information	
Cash paid for amounts included in the measurement of lease liabilities	
Operating cash flows from finance leases	(113)
Operating cash flows from operating leases	(308)
Investing cash flows for operating leases	(1,023)
Financing cash flows for finance leases	(699)
Right-of-use assets obtained in exchange for new finance lease liabilities	670
Weighted-average remaining lease term - finance leases	0.8 years
Weighted-average remaining lease term - operating leases	1.3 years
Weighted-average discount rate - finance leases	3.96%
Weighted-average discount rate - operating leases	13.22%

(1) The operating lease cost are related to drilling rigs and are capitalized as part of oil and natural gas properties on our balance sheets.

Our rent expense for the three months ended March 31, 2018, was $968.

Discount rate

Whenever possible, we utilize the implied rate in our lease agreements to measure our lease liabilities. In the absence of a readily available implied rate, we utilize our incremental borrowing rate. The incremental borrowing rate is the rate of interest that a lessee would have to pay to borrow on a collateralized basis over a similar term an amount equal to the lease payments in a similar economic environment. The lease liabilities we recorded on our balance sheet on the effective date of ASC 842 were measured utilizing an incremental borrowing rate derived from the yield on our unsecured Senior Notes and adjusted to a collateralized basis utilizing a recovery rate model that uses observed recovery rates on defaulted debt instruments.

(dollars in thousands, except per share amounts)

Lease maturities

Our lease payments for each of the next five years and thereafter are as follows:

	As of March 31, 2019		As of December 31, 2018 (1)	
	Operating leases	Financing leases	Operating leases	Financing leases
2019	$ 10,282	$ 11,366	$ 13,890	$ 12,332
2020	1,233	178	1,330	—
2021	1,292	178	1,297	—
2022	274	178	278	—
2023	205	21	205	—
Thereafter	—	—	—	—
Total minimum lease payments	13,286	11,921	17,000	12,332
Less: imputed interest	1,222	273	*	*
Total lease liability	12,064	11,648	*	*
Less: current maturities of lease obligations	9,757	11,152	*	*
Long-term lease obligations	$ 2,307	$ 496	*	*

(1) Represents undiscounted firm commitments as of December 31, 2018
* Disclosure not required under ASC 840.

Method of adoption

We adopted ASC 842 effective January 1, 2019, using the modified retrospective approach. Based on an assessment of our leasing contracts, we did not record a cumulative effect adjustment to the opening balance of accumulated deficit.

Reconciliation of Balance Sheet Statement

In accordance with ASC 842, the disclosure of the impact of adoption on our balance statement is as follows:

	As of January 1, 2019		
	Balances upon adoption	Balances without adoption of ASC 842	Effect of change
Assets			
Right of use asset from operating leases, net	$ 14,999	$ —	$ 14,999
Liabilities			
Accounts payable and accrued liabilities	12,467	—	12,467
Noncurrent operating lease obligation	2,532	—	2,532

Note 6: Derivative instruments

Overview

Our results of operations, financial condition and capital resources are highly dependent upon the prevailing market prices of, and demand for, oil, natural gas and natural gas liquids. These commodity prices are subject to wide fluctuations and market uncertainties. To mitigate a portion of this exposure, we enter into various types of derivative instruments, including commodity price swaps, collars, and basis protection swaps.

(dollars in thousands, except per share amounts)

The following table summarizes our crude oil derivatives outstanding as of March 31, 2019:

Period and type of contract	Volume MBbls	Weighted average fixed price per Bbl
2019		
Oil swaps	1,935	$ 56.06
Oil roll swaps	380	$ 0.49
2020		
Oil swaps	2,007	$ 50.56
Oil roll swaps	410	$ 0.38
2021		
Oil swaps	690	$ 46.24
Oil roll swaps	150	$ 0.30

The following table summarizes our natural gas derivatives outstanding as of March 31, 2019:

Period and type of contract	Volume BBtu	Weighted average fixed price per MMBtu
2019		
Natural gas swaps	11,713	$ 2.85
Natural gas basis swaps	8,882	$ (0.61)
2020		
Natural gas swaps	6,000	$ 2.75
Natural gas basis swaps	3,600	$ (0.46)

The following table summarizes our natural gas liquid derivatives outstanding as of March 31, 2019:

Period and type of contract	Volume Thousands of Gallons	Weighted average fixed price per gallon
2019		
Natural gasoline swaps	3,570	$ 1.39
Propane swaps	8,232	$ 0.74
2020		
Natural gasoline swaps	1,890	$ 1.39
Propane swaps	4,284	$ 0.74

Subsequent to March 31, 2019 and through May 7, 2019, we entered into additional derivative contracts, including 195 MBbls of crude oil collars scheduled to settle in 2020 with a weighted average purchased put price of $55.00 per barrel and sold call of $66.42 per barrel, and the following natural gas liquids contracts:

Period and type of contract	Volume Thousands of Gallons	Weighted average fixed price per Gallon
2019		
Iso butane	1,344	$ 0.72
Natural gasoline	1,848	$ 1.24
N-butane	3,822	$ 0.70
Propane	3,864	$ 0.64
2020		
Iso butane	630	$ 0.72
Natural gasoline	882	$ 1.24
N-butane	1,722	$ 0.70
Propane	1,890	$ 0.64

(dollars in thousands, except per share amounts)

Effect of derivative instruments on the consolidated balance sheets

All derivative financial instruments are recorded on the balance sheet at fair value. See “Note 7—Fair value measurements” for additional information regarding fair value measurements. The estimated fair values of derivative instruments are provided below. The carrying amounts of these instruments are equal to the estimated fair values.

	As at March 31, 2019			As at December 31, 2018		
	Assets	Liabilities	Net value	Assets	Liabilities	Net value
Natural gas derivative contracts	$ 891	$ (685)	$ 206	$ 833	$ (488)	$ 345
Crude oil derivative contracts	1,851	(30,764)	(28,913)	24,208	(4,452)	19,756
NGL derivative contracts	1,857	—	1,857	4,581	—	4,581
Total derivative instruments	4,599	(31,449)	(26,850)	29,622	(4,940)	24,682
Less:						
Netting adjustments (1)	(4,599)	4,599	—	(3,398)	3,398	—
Derivative instruments - current	—	(10,874)	(10,874)	24,025	—	24,025
Derivative instruments - long-term	$ —	$ (15,976)	$ (15,976)	$ 2,199	$ (1,542)	$ 657

(1) Amounts represent the impact of master netting agreements that allow us to net settle positive and negative positions with the same counterparty. Positive and negative positions with counterparties are netted only to the extent that they relate to the same current versus noncurrent classification on the balance sheet.

Effect of derivative instruments on the consolidated statements of operations

We do not apply hedge accounting to any of our derivative instruments. As a result, all gains and losses associated with our derivative contracts are recognized immediately as “Derivative (losses) gains” in the consolidated statements of operations.

“Derivative (losses) gains” in the consolidated statements of operations are comprised of the following:

	Three months ended March 31,	
	2019	2018
Change in fair value of commodity price derivatives	$ (51,531)	$ (12,257)
Settlements (paid) received on commodity price derivatives	515	(4,244)
Total derivative losses	$ (51,016)	$ (16,501)

Note 7: Fair value measurements

Fair value is defined by the FASB as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, valuation models are applied. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the price transparency for the instruments or market and the instruments’ complexity.

Fair value measurements are categorized according to the fair value hierarchy defined by the FASB. The hierarchical levels are based upon the level of judgment associated with the inputs used to measure the fair value of the assets and liabilities as follows:

- Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date.
- Level 2 inputs include quoted prices for identical or similar instruments in markets that are not active and inputs other than quoted prices that are observable for the asset or liability.
- Level 3 inputs are unobservable inputs for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability.

In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, the asset or liability is categorized based on the lowest level input that is significant to the fair value measurement in its entirety. Our assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment, and may affect the placement of assets and liabilities within the levels of the fair value hierarchy.

(dollars in thousands, except per share amounts)

Recurring fair value measurements

As of March 31, 2019, and December 31, 2018, our financial instruments recorded at fair value on a recurring basis consisted of commodity derivative contracts (see "Note 6—Derivative instruments"). We had no Level 1 assets or liabilities. Our derivative contracts classified as Level 2 consisted of commodity price swaps and oil roll swaps which are valued using an income approach. Future cash flows from the commodity price swaps are estimated based on the difference between the fixed contract price and the underlying published forward market price. Our derivative contracts classified as Level 3 consisted of collars and natural gas basis swaps. The fair value of these contracts is developed by a third-party pricing service using a proprietary valuation model, which we believe incorporates the assumptions that market participants would have made at the end of each period. Observable inputs include contractual terms, published forward pricing curves, and yield curves. Significant unobservable inputs are implied volatilities and proprietary pricing curves. Significant increases (decreases) in implied volatilities in isolation would result in a significantly higher (lower) fair value measurement. We review these valuations and the changes in the fair value measurements for reasonableness. All derivative instruments are recorded at fair value and include a measure of our own nonperformance risk for derivative liabilities or our counterparty credit risk for derivative assets.

The fair value hierarchy for our financial assets and liabilities is shown by the following table:

	As at March 31, 2019			As at December 31, 2018		
	Derivative assets	Derivative liabilities	Net assets (liabilities)	Derivative assets	Derivative liabilities	Net assets (liabilities)
Significant other observable inputs (Level 2)	$ 4,598	$ (30,910)	$ (26,312)	$ 29,370	$ (4,718)	$ 24,652
Significant unobservable inputs (Level 3)	1	(539)	(538)	252	(222)	30
Netting adjustments (1)	(4,599)	4,599	—	(3,398)	3,398	—
	$ —	$ (26,850)	(26,850)	$ 26,224	$ (1,542)	$ 24,682

(1) Amounts represent the impact of master netting agreements that allow us to net settle positive and negative positions with the same counterparty. Positive and negative positions with counterparties are netted on the balance sheet only to the extent that they relate to the same current versus noncurrent classification.

Changes in the fair value of our derivative instruments, classified as Level 3 in the fair value hierarchy, were as follows for the periods presented:

	Three months ended March 31,	
Net derivative assets (liabilities)	**2019**	**2018**
Beginning balance	$ 30	$ (295)
Realized and unrealized (losses) gains included in derivative losses	(981)	(432)
Settlements paid	413	108
Ending balance	$ (538)	$ (619)
(Losses) gains relating to instruments still held at the reporting date included in derivative losses for the period	$ (537)	$ (380)

Nonrecurring fair value measurements

Asset retirement obligations. Additions to the asset and liability associated with our asset retirement obligations are measured at fair value on a nonrecurring basis. Our asset retirement obligations consist of the estimated present value of future costs to plug and abandon or otherwise dispose of our oil and natural gas properties and related facilities. Significant inputs used in determining such obligations include estimates of plugging and abandonment costs, inflation rates, discount rates, and well life, all of which are Level 3 inputs according to the fair value hierarchy. The estimated future costs to dispose of properties added during the first three months of 2019 and 2018 were escalated using an annual inflation rate of 2.25% and 2.26%, respectively. The estimated future costs to dispose of properties added during the three months ended March 31, 2019 and 2018, were discounted with a credit-adjusted risk-free rate was 12.35% and 6.92%, respectively. These estimates may change based upon future inflation rates and changes in statutory remediation rules. See "Note 8—Asset retirement obligations" for additional information regarding our asset retirement obligations.

(dollars in thousands, except per share amounts)

Fair value of other financial instruments

Our significant financial instruments, other than derivatives, consist primarily of cash and cash equivalents, accounts receivable, accounts payable, and debt. We believe the carrying values of cash and cash equivalents, accounts receivable, and accounts payable approximate fair values due to the short-term maturities of these instruments.

The carrying value and estimated fair value of our debt were as follows:

	March 31, 2019		December 31, 2018	
Level 2	**Carrying value (1)**	**Estimated fair value**	**Carrying value (1)**	**Estimated fair value**
8.75% Senior Notes due 2023	$ 300,000	$ 207,183	$ 300,000	$ 213,618
Credit Facility	30,000	30,000	—	—
Other secured debt	8,770	8,770	8,942	8,942

(1) The carrying value excludes deductions for debt issuance costs.

The carrying value of our Credit Facility and other secured long-term debt approximates fair value because the rates are comparable to those at which we could currently borrow under similar terms, are variable and incorporate a measure of our credit risk. The fair value of our Senior Notes was estimated based on quoted market prices.

Counterparty credit risk

Our derivative contracts are executed with institutions, or affiliates of institutions, that are parties to our credit facilities at the time of execution, and we believe the credit risks associated with all of these institutions are acceptable. We do not require collateral or other security from counterparties to support derivative instruments. Master agreements are in place with each of our derivative counterparties which provide for net settlement in the event of default or termination of the contracts under each respective agreement. As a result of the netting provisions, our maximum amount of loss under derivative transactions due to credit risk is limited to the net amounts due from the counterparties under the derivatives. Our loss is further limited as any amounts due from a defaulting counterparty that is a Lender, or an affiliate of a Lender, under our credit facilities can be offset against amounts owed to such counterparty Lender. As of March 31, 2019, the counterparties to our open derivative contracts consisted of eight financial institutions, of which all were lenders under our Credit Facility.

The following table summarizes our derivative assets and liabilities which are offset in the consolidated balance sheets under our master netting agreements. It also reflects the amounts outstanding under our credit facilities that are available to offset our net derivative assets due from counterparties that are lenders under our credit facilities.

	Offset in the consolidated balance sheets			Gross amounts not offset in the consolidated balance sheets		
	Gross assets (liabilities)	**Offsetting assets (liabilities)**	**Net assets (liabilities)**	**Derivatives (1)**	**Amounts outstanding under credit facilities (2)**	**Net amount**
March 31, 2019						
Derivative assets	$ 4,599	$ (4,599)	$ —	$ —	$ —	$ —
Derivative liabilities	(31,449)	4,599	(26,850)	—	—	(26,850)
	$ (26,850)	$ —	$ (26,850)	$ —	$ —	$ (26,850)
December 31, 2018						
Derivative assets	$ 29,622	$ (3,398)	$ 26,224	$ (1,542)	$ —	$ 24,682
Derivative liabilities	(4,940)	3,398	(1,542)	1,542	—	—
	$ 24,682	$ —	$ 24,682	$ —	$ —	$ 24,682

(1) Since positive and negative positions with a counterparty are netted on the balance sheet only to the extent that they relate to the same current versus noncurrent classification, these represent remaining amounts that could have been offset under our master netting agreements.
(2) The amount outstanding under our Credit Facility that is available to offset our net derivative assets due from counterparties that are lenders under our Credit Facility.

We did not post additional collateral under any of these contracts as all of our counterparties are secured by the collateral under our credit facilities. Payment on our derivative contracts could be accelerated in the event of a default on our Credit Facility. The aggregate fair value of our derivative liabilities subject to acceleration in the event of default was $31,449 before offsets at March 31, 2019.

(dollars in thousands, except per share amounts)

Note 8: Asset retirement obligations

The following table provides a summary of our asset retirement obligation activity:

Balance at January 1, 2019	$	23,147
Liabilities incurred in current period		66
Liabilities settled or disposed in current period		(271)
Revisions in estimated cash flows		10
Accretion expense		354
Balance at March 31, 2019	$	23,306
Less current portion included in accounts payable and accrued liabilities		1,058
Asset retirement obligations, long-term	$	22,248

See “Note 7—Fair value measurements” for additional information regarding fair value assumptions associated with our asset retirement obligations.

Note 9: Deferred compensation

Cash Incentive Plan

We adopted the Long-Term Cash Incentive Plan (the “Cash LTIP”) on August 7, 2015. The Cash LTIP provides additional cash compensation to certain employees of the Company in the form of awards that generally vest in equal annual increments over a four-year period. Since the awards do not vary according to the value of the Company’s equity, the awards are not considered “stock-based compensation” under accounting guidance. We accrue for the cost of each annual increment over the period service is required to vest. A summary of compensation expense for the Cash LTIP is presented below:

	Three months ended March 31,	
	2019	2018
Cash LTIP expense (net of amounts capitalized)	$ 91	$ 95
Cash LTIP payments	—	17

As of March 31, 2019, the outstanding liability accrued for our Cash LTIP, based on requisite service provided, was $1,487. Beginning in October 2018, we ceased issuing cash grants under the Cash LTIP plan and instead are issuing restricted stock units ("RSUs") to our employees.

2017 Management Incentive Plan

In 2017, we adopted the Chaparral Energy, Inc. Management Incentive Plan (the “MIP”). The MIP provides for the following types of awards: options, stock appreciation rights, restricted stock, restricted stock units, performance awards and other incentive awards. The aggregate number of shares of Class A common stock, par value $0.01 per share, reserved for issuance pursuant to the MIP was initially set at 3,388,832 subject to changes in the event additional shares of common stock are issued under our Reorganization Plan. The MIP contemplates that any award granted under the plan may provide for the earlier termination of restrictions and acceleration of vesting in the event of a Change in Control, as may be described in the particular award agreement.

Pursuant to the MIP, we have granted restricted stock to executive employees and members of our Board of Directors (the “Board”). Grants awarded to executives are generally comprised of shares for which 75% are subject to service vesting conditions (the “Time Shares”) and 25% are subject to performance or market-based vesting conditions (the “Performance Shares”). All grants to the Board were Time Shares.

Both the Time and Performance Shares are classified as equity-based awards. Compensation cost is generally recognized and measured according to the grant date fair value of the awards which are based on the market price of our common stock for awards with service and performance conditions.

(dollars in thousands, except per share amounts)

The Time Shares vest in equal annual installments over the three-year vesting period. The Performance Shares vest in three tranches annually according to performance or market-based conditions established each year which generally relate to profitability, stock returns, drilling results and other strategic goals.

Vesting conditions for Performance Shares vesting in 2019 were established and approved by our Board in March 2019 and we have commenced recognizing expense for the related shares in the first quarter of 2019. Our Board established that all Performance Shares scheduled to vest in 2019 shall be subject to a market condition that is based on our stock return relative to a group of peer companies. Expense on these awards is based on a fair value that incorporates the probability of vesting. We utilized a Monte Carlo simulation to estimate the fair value of the market based award. The simulation utilized a risk free rate of 2.52% and volatility of 64.1% to arrive at a fair value of $4.66 per restricted share. These inputs are considered to be Level 3 inputs within the fair value hierarchy.

A summary of our restricted stock activity pursuant to our MIP is presented below:

	Time Shares			Performance Shares	
	Weighted average award date fair value	Restricted shares	Vest date fair value	Weighted average award date fair value	Restricted shares
	($ per share)			($ per share)	
Unvested and outstanding at January 1, 2019	$ 20.06	818,206		$ 20.12	$ 125,528
Granted	$ 7.97	78,378		$ 7.97	$ 15,000
Vested	$ 20.05	(73,517)	$ 525	$ —	$ —
Forfeited	$ 20.05	(73,515)		$ 20.05	$ (23,598)
Unvested and outstanding at March 31, 2019	$ 18.79	749,552		$ 18.57	$ 116,930

Beginning in October 2018, we have issued RSUs under our MIP to certain non-executive employees in lieu of cash awards. Certain RSUs are to be settled in stock upon vesting while others are to be settled in cash. The stock-settled RSUs are classified as equity awards while the cash settled RSUs are classified as liability awards. These awards, which are service-based, will vest in equal installments over a 3 year period. See "Note 1—Nature of operations and summary of significant accounting policies" in Item 8 Financial Statements and Supplementary Data of our Annual Report on Form 10-K for the year ended December 31, 2018, for a discussion of accounting policies regarding our RSUs.

A summary of our RSU activity is presented below:

	Stock-settled RSUs		Cash-settled RSUs	
	Weighted average award date fair value	Restricted units	Weighted average award date fair value	Restricted units
	($ per share)		($ per share)	
Unvested and outstanding at January 1, 2019	$ 17.66	89,633	$ 17.66	$ 37,196
Granted	$ —	—	$ 6.37	$ 1,570
Forfeited	$ 17.66	(2,554)	$ 17.66	$ (1,136)
Unvested and outstanding at March 31, 2019	$ 17.66	87,079	$ 17.19	$ 37,630

Companywide stock award

New employees are eligible for a grant of 100 shares subsequent to being employed for a certain period of time. There are no vesting requirements for these awards and thus compensation is recognized in full on the award date based on the closing price of our common stock on that date. In January 2019, 700 shares were awarded to new employees.

(dollars in thousands, except per share amounts)

Stock-based compensation cost

Compensation cost is calculated net of forfeitures. We recognize the impact of forfeitures due to employee terminations in expense as they occur instead of incorporating an estimate of such forfeitures. For awards with performance conditions, we will assess the probability that a performance condition will be achieved at each reporting period to determine whether and when to recognize compensation cost. For awards with market conditions, expense is recognized on the entire value of the award regardless of the vesting outcome so long as the participant remains employed.

A portion of stock-based compensation cost associated with employees involved in our acquisition, exploration, and development activities has been capitalized as part of our oil and natural gas properties. The remaining cost is reflected in lease operating and general and administrative expenses in the consolidated statements of operations. Stock-based compensation expense is as follows for the periods indicated:

	Three months ended March 31,	
	2019	2018
Stock-based compensation cost	$ 1,460	$ 5,580
Less: stock-based compensation cost capitalized	(626)	(957)
Stock-based compensation expense	$ 834	$ 4,623
Number of vested shares repurchased	80,422	—
Payments for stock-based compensation	$ 463	$ 1,422

Based on a quarter end market price of $5.70 per share of our Class A common stock, the aggregate intrinsic value of all restricted shares and stock settled RSUs outstanding was $5,435 as of March 31, 2019. The repurchases of shares and associated payments disclosed above were primarily for tax withholding and tax liabilities and are reflected as treasury stock transactions on our consolidated statements of stockholders' equity. As of March 31, 2019, and December 31, 2018, accrued payroll and benefits payable included for stock-based compensation costs expected to be settled within the next twelve months were $37 and $17, respectively, all of which relates to our cash-settled RSUs. Unrecognized stock-based compensation cost of approximately $4,999 as of March 31, 2019, is expected to be recognized over a weighted-average period of 1.3 years.

Note 10: Commitments and contingencies

Standby letters of credit ("Letters") available under our Credit Facility are used in lieu of surety bonds with various organizations for liabilities relating to the operation of oil and natural gas properties. We had Letters outstanding totaling $869 as of each of March 31, 2019 and December 31, 2018. When amounts under the Letters are paid by the lenders, interest accrues on the amount paid at the same interest rate applicable to borrowings under the Credit Facility. No amounts were paid by the lenders under the Letters; therefore, we paid no interest on the Letters during the three months ended March 31, 2019 or 2018.

Litigation and Claims

Chapter 11 Proceedings. Commencement of the Chapter 11 proceedings automatically stayed many of the proceedings and actions against us noted below as well as other claims and actions that were or could have been brought prior to May 9, 2016 ("Petition Date"), and the claims remain subject to Bankruptcy Court jurisdiction. With respect to the proofs of claim asserted in the Chapter 11 Cases arising from the proceedings or actions below which were initiated prior to the Petition Date, we are unable to estimate the amount of such claims that will be allowed by the Bankruptcy Court due to, among other things, the complexity and number of legal and factual issues which are necessary to determine the amount of such claims and uncertainties related to the nature of defenses asserted in connection with the claims, the potential size of the putative classes, and the types of the properties and scope of agreements related to such claims. As a result, no reserves were established in respect of such proofs of claims or any of the proceedings or actions described below. To the extent that any of the legal proceedings were filed prior to the Petition Date and result in a claim being allowed against us, pursuant to the terms of the Reorganization Plan, such claims will be satisfied through the issuance of new stock in the Company or, if the amount of such claim is below the convenience class threshold, through cash settlement. As of March 31, 2019, there are in excess of 100 remaining claims subject to Bankruptcy Court jurisdiction. Of the total alleged dollar amount of these unresolved claims, nearly all, as measured by the alleged amount of such claims, is comprised of claims from the Naylor Farms case, the W.H. Davis case and the CLO case described below. If the Bankruptcy Court were to allow the remaining unresolved proofs of claims from these cases in the full amount asserted therein, the Company, pursuant to the Plan of Reorganization, would be required to issue additional shares to the holders of such allowed proofs of claim, which could result in dilution to existing stockholders.

Naylor Farms, Inc., individually and as class representative on behalf of all similarly situated persons v. Chaparral Energy, L.L.C (the “Naylor Farms case”). On June 7, 2011, an alleged class action was filed against us in the United States District Court for the Western District of Oklahoma (Naylor Trial Court”) alleging that we improperly deducted post-production costs from royalties paid to plaintiffs and other non-governmental Royalty Interest owners from crude oil and natural gas wells we operate in Oklahoma. The plaintiffs have alleged a number of claims, including breach of contract, fraud, breach of fiduciary duty, unjust enrichment, and other claims and seek termination of leases, recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the alleged class. Plaintiffs indicated they seek damages in excess of $5,000, the majority of which would be comprised of interest and may increase with the passage of time. We responded to the Naylor Farms petition, denied the allegations and raised arguments and defenses. Plaintiffs filed a motion for class certification in October 2015. In addition, the plaintiffs filed a motion for summary judgment asking the Naylor Trial Court to determine as a matter of law that natural gas is not marketable until it is in the condition and location to enter an interstate pipeline. On May 20, 2016, we filed a Notice of Suggestion of Bankruptcy with the Naylor Trial Court. Subsequently the bankruptcy stay was lifted for the limited purpose of determining the class certification issue.

On January 17, 2017, the Naylor Trial Court certified a modified class of plaintiffs with oil and gas leases containing specific language. The modified class constitutes less than 60% of the leases the plaintiffs originally sought to certify. After additional briefing on the subject, on April 18, 2017, the Naylor Trial Court issued an order certifying the class to include only claims relating back to June 1, 2006. On May 3, 2019, our appeal of that class certification was denied by the Tenth Circuit Court of Appeals (the “Tenth Circuit”).

In addition to filing claims on behalf of the named and putative plaintiffs, on August 15, 2016, plaintiffs’ attorneys filed a proof of claim on behalf of the putative class claiming damages in excess of $150,000 in our Chapter 11 Cases. The Company objected to treatment of the claim on a class basis, asserting the claim should be addressed on an individual basis. On April 20, 2017, plaintiffs filed an amended proof of claim reducing the claim to an amount in excess of $90,000 inclusive of actual and punitive damages, statutory interest and attorney fees. On May 24, 2017, the Bankruptcy Court denied the Company’s objection, ruling the plaintiffs may file a claim on behalf of the class. This order did not establish liability or otherwise address the merits of the plaintiffs’ claims, to which we will also object. On June 7, 2017 we appealed the Bankruptcy Court order to the United States District Court for the District of Delaware.

Pursuant to the Reorganization Plan, if the plaintiffs ultimately prevail on the merits of their claims, any liability arising under judgment or settlement of the unsecured claims would be satisfied through the issuance of stock in the Company. We continue to dispute the plaintiffs’ allegations, dispute the case meets the requirements for class certification, and are objecting to the claims both individually and on a class-wide basis.

W. H. Davis Family Limited Partnership Claims in the Company’s Chapter 11 Bankruptcy Cases (the “W.H. Davis case”). The W. H. Davis Family Limited Partnership (“Davis”) filed Proofs of Claim (Nos. 1819 and 1835) in the Company’s Chapter 11 Cases. Davis claims that Chaparral owes Davis $17,262 as the result of Chaparral’s alleged diversion of CO2 from the Camrick Unit and the North Perryton Unit to the Farnsworth Unit. All these units were divested by the Company as part of its EOR asset sale in November 2017. The Camrick Unit was a tertiary recovery project located in Beaver County and Texas County, Oklahoma. The North Perryton Unit was a tertiary recovery project located in Ochiltree County, Texas. The Company was previously the operator of the Camrick and North Perryton Units and owned approximately 60% of the working interest in those units. Davis owns approximately 40% of the working interests in those units. The Company also operated the Farnsworth Unit which was a tertiary recovery project located in Ochiltree County, Texas. The Company previously owned 100% of the working interests in the Farnsworth Unit. Davis contends that the Company was required to deliver all available CO_2 sourced from the Agrium nitrogen fertilizer plant in Borger, Texas, to the Camrick and North Perryton Units and its diversion of a portion of the available CO_2 to the Farnsworth Unit constitutes a breach of contractual and fiduciary duties owed to Davis. Davis contends that the diversion has resulted in a decrease of oil production and reserves in the Camrick Unit and the North Perryton Unit. Davis contends that Chaparral caused the diversion of CO_2 from the Camrick and North Perryton Units to the Farnsworth Unit in order to profit from increased production at the Farnsworth Unit to the detriment of Davis.

The Company disputes Davis’ allegations and specifically denies that it has any contractual or fiduciary obligation to Davis as alleged in the Proofs of Claim. The Company filed objections to the Proofs of Claim in the Chapter 11 proceeding. This proceeding is pending in the Bankruptcy Court. The Bankruptcy Judge has ordered Davis and the Company to participate in a mediation of the dispute.

Pursuant to the Reorganization Plan, if Davis ultimately prevails on the merits of its claims, any liability arising under the judgment or settlement would be satisfied through the issuance of stock in the Company.

The Commissioners of the Land Office of the State of Oklahoma's Claims in the Company's Chapter 11 Bankruptcy Cases (the "CLO case"). The Commissioners of the Land Office of the State of Oklahoma ("CLO") claims that the Company is the lessee of mineral interests owned by the State of Oklahoma that are administered by the CLO. The CLO alleges that the Company has failed to pay royalties or has underpaid royalties owed to the CLO under these mineral leases and the CLO's regulations. The CLO's Proofs of Claims Nos. 2130 and 2131 allege non-payment of royalties and seek recovery of $1,697 in allegedly unpaid royalties and related interest. The CLO's Proofs of Claim Nos. 2132, 2133 and 2234 allege underpayment of royalties seek recovery of $29 in underpaid royalties and related interests.

The Company objects to the CLO's claims on several grounds, including: (1) claims fail to take into account differences in the specific lease language and applicable regulations as they have changed over time; (2) the CLO's construction of the leases and the regulations are improper; (3) the claims are based upon improper benchmark prices; (4) the claims improperly include amounts for interests; (5) the CLO seeks to impose liability on the Company for royalties where it is not CLO's lessee; and (6) the claims are barred in whole or in part by the applicable Statute of Limitations and/or the doctrines of laches and estoppel.

Pursuant to the Reorganization Plan, if the CLO ultimately prevails on the merits of its claims, any liability arising under the judgment or settlement would be satisfied through the issuance of stock in the Company.

Lisa West and Stormy Hopson, individually and as class representatives on behalf of all similarly situated persons v. Chaparral Energy, L.L.C. (the "*West* case") On February 18, 2016, an alleged class action was filed against us, as well as several other operators in the District Court of Pottawatomie County, State of Oklahoma, alleging claims on behalf of named plaintiffs and all similarly situated persons having an insurable real property interest in eight counties in central Oklahoma (the "Class Area"). The plaintiffs alleged that certain oil and gas operations conducted by us and the other defendants have induced earthquakes in the Class Area. The plaintiffs did not seek damages for property damage, but instead asked the court to require the defendants to reimburse plaintiffs and class members for earthquake insurance premiums from 2011 through the time at which the court determines there is no longer a risk of induced earthquakes, as well as attorney fees and costs and other relief. On March 18, 2016, the case was removed to the United States District Court for the Western District of Oklahoma under the Class Action Fairness Act. On April 14, 2016, we filed a motion to dismiss the claims asserted against us for failure to state a claim upon which relief can be granted. On May 20, 2016, we filed a Notice of Suggestion of Bankruptcy, informing the court that we had filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code. On October 14, 2016, the plaintiffs filed an Amended Complaint adding additional defendants and increasing the Class Area to 25 central Oklahoma counties. Other defendants filed motions to dismiss the action which were granted on May 12, 2017. On July 18, 2017, plaintiffs filed a Second Amended Complaint adding additional named plaintiffs as putative class representatives and adding three additional counties to the putative class area. In the Second Amended Complaint, plaintiffs sought damages for nuisance, negligence, abnormally dangerous activities, and trespass. Due to Chaparral's bankruptcy, plaintiffs specifically limited alleged damages related to Chaparral's disposal activities occurring after our emergence from bankruptcy on March 21, 2017. We moved to dismiss the Second Amended Complaint on September 15, 2017. On August 13, 2018, the court granted our motion to dismiss, and on August 16, 2018 issued an order striking the class allegations from the Second Amended Complaint. On August 30, 2018, plaintiffs filed a motion for a permissive appeal with the Tenth Circuit, challenging the order dismissing the class allegations. The Tenth Circuit denied plaintiffs' petition for leave to appeal on September 24, 2018. Because the plaintiffs still have live claims pending against other defendants, the district court's dismissal of the claims asserted against us are not yet final. In the event plaintiffs ultimately seek to appeal our dismissal, we will dispute the plaintiffs' claims, dispute that the case meets the requirements for a class action, dispute the remedies requested are available under Oklahoma law, and vigorously defend the case. Plaintiffs' attorneys filed a proof of claim on behalf of the putative class claiming in excess of $75,000 in our Chapter 11 Cases. We filed an objection to class treatment of the proof of claim filed by the West plaintiffs in our bankruptcy proceeding. The Bankruptcy Court heard our objection, and on February 9, 2018 granted our objection to class treatment of the proof of claim.

James Butler et al. v. Berexco, L.L.C., Chaparral Energy, L.L.C, et al. (the "*Butler* case") On October 13, 2017, a group of fifty-two individual plaintiffs filed a lawsuit in the District Court of Payne County, State of Oklahoma against twenty-six named defendants, including us, and twenty-five unnamed defendants. Plaintiffs are all property owners and residents of Payne County, Oklahoma, and allege salt water disposal activities by the defendants, owners or operators of salt water disposal wells, induced earthquakes which have caused damage to real and personal property, and emotional damages. Plaintiffs claim absolute liability for ultra-hazardous activities, negligence, gross negligence, public and private nuisance, trespass, and ask for compensatory and punitive damages. On December 18, 2017, we moved the court to dismiss the claims against us. Prior to plaintiffs responding to our motion, a hearing on a motion to stay the Butler case was held on January 4, 2018. The judge granted the motion to stay proceedings, ruling that the Butler case was stayed pending final judgment or denial of class certification in the West case. Despite the dismissal of the class allegations in the West case, the stay has not been lifted. Our motion to dismiss will not be considered until the stay is lifted, at which time, if necessary, we will dispute plaintiffs' claims, dispute that the remedies requested are available under Oklahoma law, and vigorously defend the case.

Lacheverjuan Bennett et al. v. Chaparral Energy, L.L.C., et al. On March 26, 2018, a group of twenty-seven individual plaintiffs filed a lawsuit in the District Court of Logan County, State of Oklahoma against twenty-three named defendants, including us, and twenty-five unnamed defendants. Plaintiffs are all property owners and residents of Logan County, Oklahoma, and allege the defendants, all oil and gas companies which have engaged in injection well operations, induced earthquakes which have caused damage to real and personal property, and caused emotional damages. Plaintiffs claim absolute liability for ultra-hazardous activities, negligence, gross negligence, public and private nuisance, and trespass, and ask for compensatory and punitive damages, and attorney fees and costs. On October 22, 2018, we filed a motion to dismiss the claims asserted against us for failure to state a claim upon which relief can be granted. Jointly with other defendants, we have also filed a motion to stay the proceedings pending resolution of the West case. Despite dismissal of the class allegations in the West case, the stay has not been lifted. When the stay is lifted, we will dispute the plaintiffs' claims, dispute the remedies requested are available under Oklahoma law, and vigorously defend the case.

Hallco Petroleum, Inc. v. Chaparral Energy, L.L.C. On November 7, 2017, Hallco Production, LLC ("Hallco") filed a lawsuit against us in the District Court of Kay County, State of Oklahoma. Plaintiffs alleged carbon dioxide which was injected for enhanced oil recovery in wells operated by us in the North Burbank Unit migrated to wells operated by Hallco, damaging its salt water disposal well and therefore preventing operation of, and production from, all wells on Hallco's lease. Plaintiffs allege the migration of carbon dioxide constituted trespass, and further allege negligence and nuisance. Plaintiff seeks actual damages in excess of $75, plus punitive damages in an unspecified amount. Because we sold the EOR wells on November 17, 2017, Hallco filed an amended petition on March 6, 2018 to add the purchaser, Perdure Petroleum, LLC, as an additional defendant in the lawsuit. Plaintiff claims the damage is ongoing. We dispute the plaintiff's claims, dispute the remedies requested are available under Oklahoma law, and are vigorously defending the case.

Brown & Borelli, Inc. v. Chesapeake Operating, L.L.C. et al., in the District Court of Kingfisher County, State of Oklahoma. The plaintiff filed its petition in this case on August 24, 2018. In the petition, the plaintiff alleges our use of hydraulic fracturing during completion of a certain horizontal oil and gas well caused damage to plaintiff's existing vertical wells located in another section. The plaintiff also alleges two co-defendants' completion of horizontal wells likewise caused damage to the same vertical wells. Plaintiff asserts claims for trespass and nuisance against all defendants and seeks to recover compensatory damages for the alleged loss of production to plaintiff's vertical wells. We filed an answer on October 9, 2018 disputing plaintiff's material allegations and asserting certain affirmative and other defenses. Discovery is ongoing and no scheduling order has yet been entered by the court. We will vigorously defend the case.

We are involved in various other legal proceedings including, but not limited to, commercial disputes, claims from royalty and surface owners, property damage claims, quiet title actions, personal injury claims, employment claims, and other matters which arise in the ordinary course of business. These proceedings may include allegations of damages from induced earthquakes, which we will vigorously defend as necessary. In addition, other proofs of claim have been filed in our bankruptcy case which we anticipate repudiating. While the outcome of these legal proceedings cannot be predicted with certainty, we do not expect any of them individually to have a material effect on our financial condition, results of operations or cash flows.

Contractual obligations

We have numerous contractual commitments in the ordinary course of business including debt service requirements, operating leases, financing leases and purchase obligations. Our operating leases include leases for drilling rigs, which have terms of up to 15 months, and leases on CO_2 recycle compressors, which have terms of seven years. Aside from operating leases, we also have financing leases for our CO_2 recycle compressors and fleet vehicles. In conjunction with the sale of our EOR assets, all our leased CO_2 compressors were subleased to the buyer of those assets although we remain the primary obligor in relation to U.S. Bank, the originating lessor. The subleases are structured such that the lease payments and remaining lease term are identical to the original leases. Other than additional borrowings under our Credit Facility and our new leases for fleet vehicles (see Note 5—Leases), we did not have material changes to our contractual commitments since December 31, 2018.

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

The following discussion and analysis is intended to assist in understanding our financial condition and results of operations for the three months ended March 31, 2019 and 2018. The information should be read in conjunction with our unaudited consolidated financial statements and the notes thereto included in this quarterly report as well as the information included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2018.

Statements in our discussion may be forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. For more information, see *"Cautionary Note Regarding Forward-Looking Statements."*

Overview

Chaparral Energy, Inc. (NYSE: CHAP) is an independent oil and natural gas exploration and production company headquartered in Oklahoma City and focused in Oklahoma's hydrocarbon rich STACK Play, where it has approximately 132,000 net acres primarily in Kingfisher, Canadian and Garfield counties. Beginning in the early 1990s, our operations in the area later to become known as the STACK were focused on vertical wells and waterfloods. Since late 2013, however, we have concentrated on the horizontal development of the Mississippian-age Osage and Meramec formations, Devonian-age Woodford Shale formation as well as the Pennsylvanian-age Oswego formation.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and natural gas and on our ability to find, develop and acquire oil and natural gas reserves that are economically recoverable. The preparation of our financial statements in conformity with generally accepted accounting principles ("GAAP") requires us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved oil and natural gas reserves. We use the full cost method of accounting for our oil and natural gas activities.

Our December 31, 2018, reserve estimates reflect that our production rate on current proved developed properties will decline at annual rates of approximately 25%, 17%, and 13% for the next three years. To grow our production and cash flow, we must find, develop and acquire new oil and natural gas reserves to replace those being depleted by production. Substantial capital expenditures are required to find, develop and acquire oil and natural gas reserves.

Highlights

Our financial and operating performance in the first quarter of 2019 includes the following highlights and notable developments:

- We grew net production from our STACK play to 1,434 MBoe for the three months ended March 31, 2019, an increase of 30% from the prior year period.
- Three wells from our 11-well Canadian County Merge Foraker spacing test were brought online in late March 2019 while all 11 wells from this spacing test were online by the first week of April 2019.
- Our lease operating expense per Boe decreased to $6.56/Boe, a decrease of 22% from the prior year quarter, primarily driven by production growth in our lower-cost STACK play and divestitures of certain non-core assets in 2018, which were assets characterized by higher operating costs compared to our STACK assets.
- We recorded a ceiling test impairment on our oil and natural gas properties of $49.7 million primarily due to a decrease in the price used to estimate our reserves.
- We incurred a net loss of $103.5 million during the quarter which included a $51.5 million non-cash fair value loss on our derivatives and the ceiling test impairment mentioned above.
- Total Company production was 1,874 MBoe for the three months ended March 31, 2019, an increase of 8% from the prior year period.
- We brought online 12 new gross operated wells during the first quarter, four of which were part of our joint drilling program discussed below.
- Our oil and natural gas capital expenditures for the three months ended March 31, 2019, was $76.8 million, with $65.9 million incurred for drilling and completions and $2.6 million on acquisitions.

Capital development

We incurred capital expenditures of $76.8 million for the three months ended March 31, 2019, of which $65.9 million was for drilling and completions, which included bringing online four wells drilled in the prior year, drilling and bringing online four wells, drilling 13 wells scheduled to be brought online subsequent to March 31, 2019, and participating in wells operated by others. The $65.9 million of expenditure for drilling and completions includes $3.1 million for participating in wells operated by others. These wells do not include wells under our joint development agreement which we discuss below. We were operating four horizontal drilling rigs in the STACK early during the first quarter and reduced to three rigs by the end of March 2019, which we expect to maintain for the remainder of the year. Our capital expenditures for the three months ended March 31, 2019 also includes $2.6 million on acquisitions.

Joint development agreement

In 2017, we entered into a joint development agreement ("JDA") with BCE Roadrunner, LLC, a wholly-owned subsidiary of Bayou City Energy ("BCE"), pursuant to which BCE will fund 100 percent of our drilling, completion and equipping costs associated with 30 STACK wells. The provisions of the JDA are described more fully in "Note 1—Nature of operations and summary of significant accounting policies" in Item 1. Financial Statements of this report. During the three months ended March 31, 2019, we drilled and brought online two wells and brought online two wells drilled in the prior year. As of March 31, 2019, we have drilled and brought online 26 wells under the JDA and have three already drilled but scheduled to be online in the second quarter.

Our drilling and completion costs to date have exceeded the well cost caps specified under the JDA primarily due to inflation in the cost of oilfield services as a result of the rebound in industry conditions. In our negotiation with BCE to cover the inflationary cost increases, BCE had indicated willingness to increase the per well cost caps on remaining wells in exchange for adding more wells to the current program. Since we have achieved our goal of utilizing the JDA as a means to delineate our acreage in Garfield and Canadian counties, Oklahoma, we do not currently plan for any expansion of the JDA. We have therefore recorded additions to oil and natural gas properties of $3.2 million in costs exceeding the cost caps for the three months ended March 31, 2019 and $16.4 million since program inception. These increases to our capital expenditures do not change our pre-reversionary interest of 15%. During the three months ended March 31, 2019, we also incurred an additional $5.4 million to acquire additional working interest on certain wells within the program through force pooling that was not subject to the JDA .

Price uncertainty and the full-cost ceiling impairment

Crude oil prices are volatile and a decline in commodity prices negatively impacts our revenues, profitability, cash flows, liquidity, and reserves, which could lead us to consider reductions in our capital program, asset sales or organizational changes.

Crude oil prices experienced a sharp decline in November 2018 and remained at depressed levels for the better part of the first quarter of 2019 before staging a modest recovery in recent weeks. Our realized price per barrel of crude oil decreased by approximately 14% during the first quarter of 2019 compared to the prior year quarter.

We mitigate the effects of volatility in commodity prices primarily by working to make our overall cost structure competitive and supportive in a low oil price environment. In addition, we maintain flexibility in our capital investment program with a diversified drilling portfolio and limited long-term commitments, which enables us to respond quickly to industry price volatility. We also deal with price volatility by hedging a substantial portion of our expected future oil and natural gas production to reduce our exposure to commodity price decreases. We currently have derivative contracts in place for a portion of production from 2019 through 2021 as disclosed in Item 3. Quantitative and Qualitative Disclosures About Market Risk. The prices we receive for our oil and natural gas production affect our: (i) cash flow available for capital expenditures, (ii) ability to borrow and raise additional capital, (iii) ability to service debt, (iv) quantity of oil and natural gas we can produce, (v) quantity of oil and natural gas reserves, and (vi) operating results for oil and natural gas activities.

Price volatility also impacts our business through the full cost ceiling test calculation. The ceiling test calculation dictates that we use the unweighted arithmetic average price of crude oil and natural gas as of the first day of each month for the 12-month period ending on the balance sheet date. Since the prices used in the cost ceiling are based on a trailing 12-month period, the full impact of price changes on our financial statements may not be recognized immediately but could be spread over several reporting periods. During the three months ended March 31, 2019, we recorded a ceiling test write-down of $49.7 million primarily due to lower pricing used to estimate our reserves as disclosed in the table below. If crude oil prices remain at their current level or decline , we expect the trailing 12-month average price to decline as we progress through 2019 and we believe that it is reasonably possible that we would record further ceiling test impairment losses in 2019. In addition to commodity prices, our production rates, levels of proved reserves, estimated future operating expenses, estimated future development costs, transfers of unevaluated properties and other factors will determine our actual ceiling test calculation and impairment analyses in future periods. Please see "Note 1—Nature of operations and summary of significant accounting policies" in Item 1. Financial Statements of this report for further discussion of our ceiling test.

	March 31, 2019	December 31, 2018
Oil (per Bbl)	$ 63.06	$ 65.56
Natural gas (per MMbtu)	$ 3.07	$ 3.10
Natural gas liquids (per Bbl)	$ 24.60	$ 25.56

Results of operations

Production

Production volumes by area were as follows (MBoe):

	Three months ended March 31, 2019	Three months ended March 31, 2018
STACK Areas:		
STACK - Kingfisher County	605	677
STACK - Canadian County	476	249
STACK - Garfield County	296	145
STACK - Other	57	36
Total STACK Areas	1,434	1,107
Other	440	630
Total	1,874	1,737

Our total net production of 1,874 MBoe for the three months ended March 31, 2019, increased approximately 8% compared to net production for the prior year quarter. The increases were primarily a result of production growth in our STACK Area. Net production from our STACK play was 1,434 MBoe for the three months ended March 31, 2019, an increase of 30% from the prior year period. This pattern of growth underscores our sole focus on developing the STACK which includes bringing online 54 gross (34 net) operated new wells in area in the last 12 months.

Revenues and transportation and processing

Our commodity sales are derived from the production and sale of oil, natural gas and natural gas liquids. These revenues do not include the effects of derivative instruments and may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

The following table presents information about our production and commodity sales before the effects of commodity derivative settlements:

	Three months ended March 31,	
	2019	2018
Commodity sales (in thousands):		
Oil	$ 32,802	$ 43,050
Natural gas	11,206	8,736
Natural gas liquids	9,217	9,591
Gross commodity sales	$ 53,225	$ 61,377
Transportation and processing	(4,606)	(3,488)
Net commodity sales	$ 48,619	$ 57,889
Production:		
Oil (MBbls)	618	697
Natural gas (MMcf)	4,474	3,788
Natural gas liquids (MBbls)	510	409
MBoe	1,874	1,737
Average daily production (Boe/d)	20,819	19,300
Average sales prices (excluding derivative settlements):		
Oil per Bbl	$ 53.08	$ 61.76
Natural gas per Mcf	$ 2.50	$ 2.31
NGLs per Bbl	$ 18.07	$ 23.45
Transportation and processing per Boe	$ (2.46)	$ (2.01)
Average sales price per Boe	$ 25.95	$ 33.33

Our gross commodity sales of $53.2 million (excludes transportation and processing deductions) for the three months ended March 31, 2019, decreased approximately 13% compared to gross commodity sales for the prior year period. The decrease for the three months ended March 31, 2019, compared to the prior year quarter is primarily due to a decrease in both crude oil production and crude oil prices. The table below discloses the impact of price and production volume changes on our revenues.

Despite an increase in overall production on a Boe basis, revenues have also declined due to a shift in our production mix which has tilted more toward natural gas and NGLs in the quarter ended March 31, 2019 compared to the prior year quarter and subsequently brought about the aforementioned decline in crude oil production. Our production mix shift can be primarily attributed to our recent development activities and growth in STACK areas that are more prolific for natural gas liquids and natural gas production as well as our divestiture of non-core assets in the prior year. As a result of growth in our STACK play, our net natural gas production for the period increased 18% compared to the prior year periods and our net natural gas liquids production increased 25%.

(in thousands)	Three months ended March 31, 2019 vs. 2018 Sales change	Percentage change in sales
Change in oil sales due to:		
Prices	$ (5,369)	(12.5)%
Production	(4,879)	(11.3)%
Total change in oil sales	$ (10,248)	(23.8)%
Change in natural gas sales due to:		
Prices	$ 885	10.2 %
Production	1,585	18.1 %
Total change in natural gas sales	$ 2,470	28.3 %
Change in natural gas liquids sales due to:		
Prices	$ (2,742)	(28.6)%
Production	2,368	24.7 %
Total change in natural gas liquids sales	$ (374)	(3.9)%

Transportation and processing revenue deductions principally consist of deductions by our customers for costs to prepare and transport production from the wellhead to a specified sales point and processing costs of gas into natural gas liquids. Transportation and processing deductions were $4.6 million for the three months ended March 31, 2019, representing an increase of 32% compared to the prior year period. Transportation and processing deductions were higher as a result of increased production of natural gas and natural gas liquids as well as higher rates. The increases have been driven by production growth in our STACK area where we have experienced higher transportation and processing costs compared to our other operating areas due to new infrastructure being built in the area. We are also experiencing higher per unit costs associated with our non-operated wells and a larger proportion of gas production subject to fee based processing arrangements as opposed to percentage of proceeds arrangements.

Derivative activities

Our results of operations, financial condition and capital resources are highly dependent upon the prevailing market prices of, and demand for, oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties. To mitigate a portion of this exposure, we have entered into various types of derivative instruments, including commodity price swaps and costless collars.

We closely monitor the fair value of our derivative contracts and may elect to settle a contract prior to its scheduled maturity date in order to lock in a gain or loss.

Our realized prices are impacted by realized gains and losses resulting from commodity derivatives contracts. The following table presents information about the effects of derivative settlements on realized prices:

	Three months ended March 31,	
	2019	2018
Oil (per Bbl):		
Before derivative settlements	$ 53.08	$ 61.76
After derivative settlements	$ 54.71	$ 56.26
Post-settlement to pre-settlement price	103.1%	91.1%
Natural gas liquids (per Bbl):		
Before derivative settlements	$ 18.07	$ 23.45
After derivative settlements	$ 19.18	*
Post-settlement to pre-settlement price	106.1%	*
Natural gas (per Mcf):		
Before derivative settlements	$ 2.50	$ 2.31
After derivative settlements	$ 2.27	$ 2.20
Post-settlement to pre-settlement price	90.8%	95.2%

* Not applicable as we did not hedge NGL prices prior to the second quarter of 2018.

The estimated fair values of our oil, natural gas, and NGL derivative instruments are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

(in thousands)	March 31, 2019	December 31, 2018
Derivative (liabilities) assets:		
Crude oil derivatives	$ (28,913)	$ 19,756
Natural gas derivatives	206	345
NGL derivatives	1,857	4,581
Net derivative (liabilities) assets	$ (26,850)	$ 24,682

The effects of derivative activities on our results of operations and cash flows were as follows:

	Three months ended March 31,			
	2019		2018	
(in thousands)	Non-cash fair value adjustment	Settlements (paid) received	Non-cash fair value adjustment	Settlements (paid) received
Derivative (losses) gains:				
Crude oil derivatives	$ (48,669)	$ 1,011	$ (12,429)	$ (3,840)
Natural gas derivatives	(139)	(1,061)	172	(404)
NGL derivatives	(2,723)	565	—	—
Derivative (losses) gains	$ (51,531)	$ 515	$ (12,257)	$ (4,244)

We do not apply hedge accounting to any of our derivative instruments. As a result, all gains and losses associated with our derivative contracts are recognized immediately as "Derivative losses" in our consolidated statements of operations. The fluctuation in derivative (losses) gains from period to period is due primarily to the significant volatility of oil and natural gas prices and to changes in our outstanding derivative contracts during these periods.

Lease operating expenses

(in thousands, except per Boe data)	Three months ended March 31, 2019	2018
Lease operating expenses:		
STACK Areas	$ 7,114	$ 5,948
Other	5,180	8,595
Total lease operating expenses	$ 12,294	$ 14,543
Lease operating expenses per Boe:		
STACK Areas	$ 4.96	$ 5.37
Other	$ 11.77	$ 13.64
Lease operating expenses per Boe	$ 6.56	$ 8.37

Lease operating expenses ("LOE") are sensitive to changes in demand for field equipment, services, and qualified operational personnel, which is driven by demand for oil and natural gas. However, the timing of changes in operating costs may lag behind changes in commodity prices.

LOE for the three months ended March 31, 2019 was $12.3 million, a decrease of 15% compared to the prior year quarter. The decrease was due to the divestiture of high-cost non-core assets in 2018 partially offset by LOE increases in the STACK where we are growing production. LOE per Boe of $6.56 was 22% lower than the prior year quarter primarily as a result of the divestitures and the STACK growth described above. LOE per Boe of $4.96 in our STACK Areas was 8% lower compared to the prior year quarter as a result of a decrease in water hauling costs in certain areas of the STACK as pipeline infrastructure is expanded into the area and contract rates are locked in, a decrease in overall LOE charges on properties operated by others and a decrease in well work activity.

Production taxes (which include severance and valorem taxes)

	Three months ended March 31, 2019	2018
Production taxes (in thousands)	$ 2,880	$ 2,677
Production taxes per Boe	$ 1.54	$ 1.54
Production taxes as % of commodity sales	5.4%	4.4%

Production taxes for the three months ended March 31, 2019, of $2.9 million, were 8% higher than the prior year. The increases were a result of the legislative tax increases discussed below. Production taxes on a per Boe basis did not increase despite the legislative rate increases as our production growth is attributable to natural gas and NGLs which are sold at lower prices compared to crude oil.

In March 2018, the Oklahoma legislature approved a production tax increase from 2% to 5% during the first three years of production on horizontal wells spudded after July 1, 2015. The production tax rate on any new well is currently 5% of commodity revenues for the first 36 months and 7% thereafter.

Depreciation, depletion and amortization ("DD&A")

	Three months ended March 31,	
	2019	2018
DD&A (in thousands):		
Oil and natural gas properties (1)	$ 21,881	$ 18,459
Property and equipment	1,834	2,647
Total DD&A	$ 23,715	$ 21,106
DD&A per Boe:		
Oil and natural gas properties (1)	$ 11.67	$ 10.63
Other fixed assets	0.98	1.52
Total DD&A per Boe	$ 12.65	$ 12.15

(1) Includes accretion of asset retirement obligations

We adjust our DD&A rate on oil and natural gas properties each quarter for changes in our estimates of oil and natural gas reserves and costs. Oil and natural gas DD&A for the three months ended March 31, 2019, of $21.9 million, was 19% higher than the prior year period due to higher production and a higher DD&A rate.

General and administrative expenses ("G&A")

	Three months ended March 31,	
(in thousands)	2019	2018
G&A:		
Gross G&A expenses	$ 11,035	$ 13,934
Capitalized exploration and development costs	(2,722)	(2,427)
Net G&A expenses	8,313	11,507
Net G&A expense per Boe	$ 4.44	$ 6.62

Net G&A of $8.3 million for the three months ended March 31, 2019, decreased from the prior year quarter primarily due to lower stock based compensation expense partially offset by one-time severance costs associated with the departure of certain company officers as disclosed below:

	Three months ended March 31,	
(in thousands)	2019	2018
Officer severance costs	$ 1,058	$ —
Stock compensation, gross	1,419	5,580
	$ 2,477	$ 5,580

Stock compensation expense was lower for the three months ended March 31, 2019, compared to the prior year quarter due to forfeitures in the current quarter and because our executive stock grants are front loaded for three-year periods and subject to accelerated cost recognition which results in higher expense early during the life of a grant with graded vesting.

Other expense

Other expense consists of the following (in thousands):

	Three months ended March 31,	
	2019	2018
Restructuring	$ —	$ 425
Subleases	403	403
Total other expense	$ 403	$ 828

Restructuring expense. We previously incurred exit costs in conjunction with our EOR asset divestiture, which are predominantly comprised of one-time severance and termination benefits for the affected employees. The expense recorded in 2018 is a result of termination benefits for the final slate of employees terminated as a result of the divestiture.

Subleases. Our subleases are comprised of CO_2 compressors that were previously utilized in our EOR operations and leased as both financing and operating leases from U.S. Bank but are now subleased to the purchaser of our EOR assets (the "Sublessee"). Minimum payments under the subleases are equal to the original leases and hence we did not record any losses upon initiation of the subleases. Prior to the asset sale, the financing leases were included in our full cost amortization base and hence subject to amortization on a units-of-production basis, while also incurring interest expense. The payments under our operating leases were previously recorded as "Lease operating" expense on our statement of operations. Based on the facts and circumstances relating to our original leases and the current subleases, we determined that all the subleases were to be classified as operating leases from a lessor's standpoint. Subsequent to the execution of the subleases in November 2017, all payments received from the Sublessee are reflected as "Sublease revenue" on our statement of operations. Minimum payments we make to U.S. Bank on the original operating leases are reflected as "Other" expense on our statement of operations. With respect to the financing leases, upon executing the subleases, we reclassified the amount associated with these leases from the full cost amortization base to "Property and equipment, net" on our balance sheet and have amortized the asset on a straight line basis prospectively. We will continue incurring interest expense on the financing leases. Please see "Note 5— Leases" in Item 1. Financial Statements of this report for further discussion of our leases.

Income taxes

We did not record any net deferred tax benefit for the three months ended March 31, 2019, as any deferred tax asset arising from the benefit is reduced by a valuation allowance as utilization of the loss carryforwards and realization of other deferred tax assets cannot be reasonably assured. Please see "Note 12— Income Taxes" in Item 8. Financial Statement and Supplementary Data of our Annual Report on Form 10-K for the year ended December 31, 2018, which contains additional information about our income taxes.

Other income and expenses

Interest expense. The following table presents interest expense for the periods indicated:

	Three months ended March 31,	
(in thousands)	**2019**	**2018**
Credit Facility	$ 150	$ 2,204
Senior Notes	6,563	—
Bank fees, other interest and amortization of issuance costs	1,343	688
Interest expense, gross	8,056	2,892
Capitalized interest	(3,492)	(1,521)
Total interest expense	$ 4,564	$ 1,371
Average borrowings	$ 333,708	$ 217,435

Interest expense for the three months ended March 31, 2019, of $4.6 million, was higher than the prior year quarter, due to an increase in gross interest expense partially offset by an increase in capitalized interest. Gross interest expense was higher primarily due to a larger balance of outstanding debt, comprised primarily of our Senior Notes, coupled with an increase in the effective interest rate on our indebtedness. Our Senior Notes, which comprised the majority of our debt in the quarter ended March 31, 2019, carries a significantly higher interest rate compared to the interest rate on our Credit Facility, which comprised the majority of our debt in the prior year quarter. Capitalized interest for the three months ended March 31, 2019 of $3.5 million, increased compared to the prior year periods due to the larger average balance in unevaluated non-producing leasehold. As a result of applying fresh start accounting upon our emergence from bankruptcy in March 2017, the carrying value of our unevaluated non-producing leasehold was significantly increased to reflect the fair value of our acreage in the STACK. However, we do not record capitalized interest on the portion of our unevaluated non-producing leasehold that resulted from the fresh start fair value adjustment.

Reorganization items

Reorganization items reflect, where applicable, expenses, gains and losses incurred that are incremental and a direct result of the reorganization of the business. As a result of our emergence from bankruptcy, we have also recorded gains on the settlement of liabilities subject to compromise and gains from restating our balance sheet to fair values under fresh start accounting. Our reorganization items are presented below:

	Three months ended March 31,	
	2019	2018
Loss on the settlement of liabilities subject to compromise	$ —	$ 48
Professional fees	463	989
Total reorganization items	$ 463	$ 1,037

"Professional fees" in the table above is comprised of legal fees for continuing work to resolve outstanding bankruptcy claims and fees to the U.S. Bankruptcy Trustee, which we will continue to incur until our bankruptcy case is closed.

Liquidity and capital resources

Our primary sources of liquidity have historically been cash flows generated from operating activities, financing provided by our revolving credit facility or issuance of debt and proceeds from hedge settlements. Additionally, in recent years, asset dispositions and our joint development arrangement have provided a source of cash flow for enhancing liquidity.

Our business strategy requires that we continuously commit substantial investment to drill and develop our oil and natural gas properties such that production from new wells can offset the natural production decline from existing wells. During the past three years, cash flows from operations have been insufficient to fully fund our capital programs and were funded by revolver borrowings and cash on hand.

As of March 31, 2019, our cash balance was $11.1 million. Our Credit Facility, which has a borrowing base of $325.0 million, had an outstanding balance of $30.0 million and $154.0 million in availability. As of May 7, 2019, our cash balance was approximately $41.9 million with $85.0 million outstanding on our Credit Facility. Availability under our Credit Facility is subject to borrowing base redetermination semi-annually on or around May 1 and November 1, or upon occurrence of certain specified events. We continuously monitor our liquidity needs, coordinate our capital expenditure program with our expected cash flows, and evaluate our available alternative sources of liquidity. We believe that we have sufficient liquidity to fund our capital expenditures and day to day operations at a minimum for the next 12 months.

Our near term liquidity is impacted by our 11-well Canadian County Merge Foraker spacing test. While we expended a substantial amount of capital during the first quarter of 2019 to drill and complete these wells, the wells only began production during the last week of March and early April 2019, with three wells online by the end of the first quarter and the remainder online by the first week of April.

Our cash flows and liquidity are highly dependent on the prices we receive for oil, natural gas and NGLs. Prices we receive are determined by prevailing market conditions, regional and worldwide economic and geopolitical activity, supply versus demand, weather, seasonality and other factors that influence market conditions and often result in significant volatility in commodity prices. In addition to reducing revenue from commodity sales, low prices can adversely affect our liquidity through the impact on the borrowing base under our credit facilities. When commodity prices decline, the price deck approved by our lenders to determine our borrowing base decreases which leads to a reduction in our borrowing base and hence the available amount we can borrow.

We mitigate the impact of volatility in commodity prices, in part through the use of derivative instruments which help stabilize our cash flow. We currently have derivative contracts in place for a portion of our oil, natural gas and natural gas liquids production from 2018 through 2021 (see Item 3. Quantitative and Qualitative Disclosures About Market Risk).

Sources and uses of cash

Our net change in cash is summarized as follows:

(in thousands)	Three months ended March 31, 2019	2018
Cash flows provided by operating activities	$ 8,554	$ 10,376
Cash flows used in investing activities	(63,529)	(104,112)
Cash flows provided by financing activities	28,647	78,193
Net decrease in cash during the period	$ (26,328)	$ (15,543)

Our cash flows from operating activities is derived substantially from the production and sale of oil and natural gas. Cash flows from operating activities for the three months ended March 31, 2019, of $8.6 million, decreased compared to the prior year. The decrease was primarily due to lower commodity revenues partially offset by lower operating costs and changes in working capital.

We use the net cash provided by operations to partially fund our acquisition, exploration and development activities. During 2019, we also relied on borrowings from our Credit Facility and cash on hand to fund our capital expenditures.

Our cash flows from investing activities is typically comprised primarily of cash outflows for capital expenditures, cash inflows from asset dispositions and derivative settlement payments of receipts.

Our actual costs incurred, including costs that we have accrued for during the three months ended March 31, 2019, and our budgeted 2019 capital expenditures for oil and natural gas properties are summarized in the table below.

	Three months ended March 31, 2019			2019 Budget	
(in thousands)	STACK	Other	Total	Low	High
Acquisitions	$ 2,558	$ —	$ 2,558	$ 12,500	$ 17,500
Drilling (1)	65,866	—	65,866	227,500	247,500
Enhancements	2,345	857	3,202	10,000	10,000
Operational capital expenditures incurred	70,769	857	71,626	250,000	275,000
Other (2)	—	—	5,183	25,000	25,000
Total capital expenditures incurred	$ 70,769	$ 857	$ 76,809	$ 275,000	$ 300,000

(1) Includes $3.1 million on development of wells operated by others and $8.5 million on our joint development agreement. Of the $8.5 million incurred on our joint development program, $3.2 million was incurred on costs that were in excess of the well cost caps specified under the agreement as a result of inflation and $5.4 million was incurred to acquire additional working interests.

(2) For the three months ended March 31, 2019, this amount includes $2.7 million for capitalized general and administrative expenses, $3.5 million for capitalized interest offset by $1.0 million in insurance reimbursements on asset retirement obligations. For our 2019 capital budget, this amount includes budgeted capitalized interest and budgeted capitalized general and administrative expenses.

Net cash used in investing activities during the three months ended March 31, 2019 was comprised of cash outflows for capital expenditure of $64.0 million partially offset by receipts for derivative settlements of $0.5 million. Net cash used in investing activities during the three months ended March 31, 2018 was comprised of cash outflows for capital expenditure of $99.9 million and payments for derivative settlements of $4.2 million. Capital expenditures during the three months ended March 31, 2018 included the closing payment of $54.8 million on our 7,000 acre leasehold purchase in January 2018.

Net cash from financing activities during the three months ended March 31, 2019, was comprised borrowings on our Credit Facility of $30.0 million partially offset by cash outflows for repayment of debt and financing leases of $0.9 million and for treasury stock repurchases of $0.5 million. Net cash from financing activities during the three months ended March 31, 2018, was comprised of cash inflows of $79.0 million from borrowings partially offset by cash outflows for repayment of debt and financing leases of $0.8 million.

Indebtedness

Debt consists of the following as of the dates indicated:

(in thousands)	March 31, 2019	December 31, 2018
8.75% Senior Notes due 2023	$ 300,000	$ 300,000
Credit Facility	30,000	—
Real estate mortgage notes	8,433	8,588
Financing lease obligations	11,648	11,677
Installment note payable	337	354
Unamortized issuance costs	(12,366)	(13,148)
Total debt, net	$ 338,052	$ 307,471

Credit Facility

The Credit Facility is a $750.0 million facility collateralized by our oil and natural gas properties and is scheduled to mature on December 21, 2022. Availability under our Credit Facility is subject to a borrowing base based on the value of our oil and natural gas properties and set by the banks semi-annually on or around May 1 and November 1 of each year. In addition, the lenders may request a borrowing base redetermination once between each scheduled redetermination or upon the occurrence of certain specified events. The banks establish a borrowing base by making an estimate of the collateral value of our oil and natural gas properties. If oil and natural gas prices decrease from the amounts used in estimating the collateral value of our oil and natural gas properties, the borrowing base may be reduced, thus reducing funds available under the borrowing base.

As of March 31, 2019, our borrowing base on the Credit Facility was $325.0 million. The unused portion, after taking into account letters of credit and outstanding borrowings was $294.1 million and availability was $154.0 million. Our availability was lower than the unused borrowing base capacity as a result of the constraints placed by the Ratio of Total Debt to EBITDAX (as defined in the Credit Facility) covenant discussed below.

The Credit Facility contains financial covenants that require, for each fiscal quarter, we maintain: (1) a Current Ratio (as defined in the Credit Facility) of no less than 1.00 to 1.00, and (2) a Ratio of Total Debt to EBITDAX (as defined in the Credit Facility) of no greater than 4.0 to 1.0 calculated on a trailing four-quarter basis. We were in compliance with these financial covenants as of March 31, 2019.

The Credit Facility contains covenants and events of default customary for oil and natural gas reserve-based lending facilities. Please see "Note 8—Debt" in Item 8 Financial Statements and Supplementary Data of our Annual Report on Form 10-K for the year ended December 31, 2018, for a discussion of the material provisions of our Credit Facility.

On May 2, 2019, we entered into the Third Amendment. The Third Amendment, which was effective March 31, 2019 reaffirmed our borrowing base at the same level as it was at the beginning of 2019, at $325.0 million.

8.75% Senior Notes

On June 29, 2018, we issued at par $300.0 million in aggregate principal amount of our Senior Notes in a private placement under Rule 144A and Regulation S of the Securities Act of 1933, as amended. The estimated offering costs were $7.3 million resulting in net proceeds of $292.7 million, which we used to repay the Credit Facility and for general corporate purposes.

The Senior Notes bear interest at a rate of 8.75% per year beginning June 29, 2018 (payable semi-annually in arrears on January 15 and July 15 of each year, beginning on January 15, 2019) and will mature on July 15, 2023.

The Senior Notes are the Company's senior unsecured obligations and will rank equal in right of payment with all of the Company's existing and future senior indebtedness, senior to all of the Company's existing and future subordinated indebtedness and effectively subordinated to all of the Company's existing and future secured indebtedness, to the extent of the value of the collateral securing such indebtedness. Please see "Note 8—Debt" in Item 8 Financial Statements and Supplementary Data of our Annual Report on Form 10-K for the year ended December 31, 2018, for a discussion of the material provisions of our Senior Notes.

Finance leases

During 2013, we entered into lease financing agreements with U.S. Bank for $24.5 million through the sale and subsequent leaseback of existing compressors owned by us. The lease financing obligations were for 84-month terms and with minimum lease payments of $3.2 million annually. As discussed above, these compressors are currently being subleased.

During 2019, we entered into lease financing agreements for our fleet trucks for $0.7 million. The lease financing obligations are for 48-month terms with the option for us to purchase the vehicle at any time during the lease term by paying the lessor's remaining unamortized cost in the vehicle. At the end of the lease term, the lessor's remaining unamortized cost in the vehicle will be a de minimis amount and hence title to the vehicle can be transferred to us at minimal cost.

Contractual obligations

We have numerous contractual commitments in the ordinary course of business including debt service requirements, operating leases, financing leases and purchase obligations. Our operating leases include leases for drilling rigs, which have terms of up to 15 months, and leases on CO_2 recycle compressors, which have terms of seven years. Aside from operating leases, we also have financing leases for our CO_2 recycle compressors and fleet vehicles. In conjunction with the sale of our EOR assets, all our leased CO_2 compressors were subleased to the buyer of those assets although we remain the primary obligor in relation to U.S. Bank, the originating lessor. The subleases are structured such that the lease payments and remaining lease term are identical to the original leases. Other than additional borrowings under our Credit Facility and our new leases for fleet vehicles, we did not have material changes to our contractual commitments since December 31, 2018.

Financial position

We believe that the following discussion of material changes in our balance sheet may be useful:

(in thousands)	March 31, 2019	December 31, 2018	Change
Assets			
Right of use asset from operating leases	$ 12,064	$ —	$ 12,064
Liabilities			
Accounts payable and accrued liabilities	$ 97,404	$ 73,779	$ 23,625
Revenue distribution payable	20,714	26,225	(5,511)
Accrued interest payable	5,934	13,359	(7,425)
Long-term debt and financing leases	338,052	307,471	30,581
Derivative instrument liabilities (assets) net	26,850	(24,682)	51,532

- We recognized a right of use asset on operating leases pursuant to our adoption of the new lease accounting standard. The amount reflects our operating lease liabilities on compressors and drilling rigs.
- Accounts payable and accrued liabilities increased primarily as a result of increased capital activity and the addition of $9.8 million in operating lease liabilities pursuant to our adoption of the new lease accounting standard.
- Revenue distribution payable decreased primarily due to payments processed on several wells that were awaiting final title determination at the end of 2018.
- Accrued interest payable decreased due to the payment of interest on our Senior Notes which have coupon payment dates on January 15 and July 15 of each year.
- Long-term debt was higher in total primarily due to $30.0 million in borrowings on our Credit Facility.
- Our portfolio of derivative instruments reverted from a net asset to a net liability as a result of an increase in forward commodity prices.

Non-GAAP financial measure and reconciliation

Management uses Adjusted EBITDA (as defined below) as a supplemental financial measurement to evaluate our operational trends. Items excluded generally represent non-cash and/or non-recurring adjustments, the timing and amount of which cannot be reasonably estimated and are not considered by management when measuring our overall operating performance. In addition, Adjusted EBITDA is generally consistent with the EBITDAX calculation that is used in the Ratio of Total Debt to EBITDAX covenant under our Credit Facility. We consider compliance with this covenant to be material.

Adjusted EBITDA is used as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to net income, as an indicator of our operating performance, as an alternative to cash flows from operating activities, or as a measure of liquidity. Adjusted EBITDA is not defined under GAAP and, accordingly, it may not be a comparable measurement to those used by other companies.

We define adjusted EBITDA as net income, adjusted to exclude (1) asset impairments, (2) interest and other financing costs, net of capitalized interest, (3) income taxes, (4) depreciation, depletion and amortization, (5) non-cash change in fair value of non-hedge derivative instruments, (6) interest income, (7) stock-based compensation expense, (8) gain or loss on disposed assets, (9) impairment charges, (10) other significant, unusual non-cash charges and (11) certain expenses related to our restructuring, cost reduction initiatives, reorganization, severance agreements and fresh start accounting activities for which our lenders have permitted us to exclude when calculating covenant compliance.

The following tables provide a reconciliation of net loss to adjusted EBITDA for the specified periods:

	Three months ended March 31,	
(in thousands)	**2019**	**2018**
Net loss	(103,540)	(11,442)
Interest expense	4,564	1,371
Depreciation, depletion, and amortization	23,715	21,106
Non-cash change in fair value of derivative instruments	51,531	12,257
Impact of derivative repricing	—	(572)
Loss on settlement of liabilities subject to compromise	—	48
Interest income	—	(1)
Stock-based compensation expense	802	4,623
Loss on sale of assets	1	1,044
Loss on impairment of assets	49,722	—
Restructuring, reorganization and other	1,520	989
Adjusted EBITDA	$ 28,315	$ 29,423

Our Credit Facility requires us to maintain a current ratio (as defined in Credit Facility) of not less than 1.0 to 1.0. The definition of current assets and current liabilities used for determination of the current ratio computed for loan compliance purposes differs from current assets and current liabilities determined in compliance with GAAP. Since compliance with financial covenants is a material requirement under our Credit Facility, we consider the current ratio calculated under our Credit Facility to be a useful measure of our liquidity because it includes the funds available to us under our Credit Facility and is not affected by the volatility in working capital caused by changes in the fair value of derivatives. The following table discloses the current ratio for our loan compliance compared to the ratio calculated per GAAP:

(dollars in thousands)	**March 31, 2019**	**December 31, 2018**
Current assets per GAAP	$ 80,286	$ 134,431
Plus—Availability under Credit Facility	153,956	208,355
Less—Short term derivative instruments	—	(24,025)
Current assets as adjusted	$ 234,242	$ 318,761
Current liabilities per GAAP	153,200	136,710
Less—Current derivative instruments	(10,874)	—
Less—Current operating lease obligation	(9,757)	—
Less—Current asset retirement obligation	(1,058)	(1,057)
Less—Current maturities of long term debt	(11,854)	(12,371)
Current liabilities as adjusted	$ 119,657	$ 123,282
Current ratio per GAAP	0.52	0.98
Current ratio for loan compliance	1.96	2.59

Off-Balance Sheet Arrangements

At March 31, 2019, we did not have any off-balance sheet arrangements.

Critical accounting policies

For a discussion of our critical accounting policies, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in our Annual Report on Form 10-K for the year ended December 31, 2018.

Also see the footnote disclosures included in “Note 1—Nature of operations and summary of significant accounting policies” and “Note 5—Leases” in Item 1. Financial Statements of this report.

Recent accounting pronouncements

See recently adopted and issued accounting standards in “Note 1—Nature of operations and summary of significant accounting policies” in Item 1. Financial Statements of this report.

ITEM 3. ***QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK***

Commodity prices

Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of, and demand for, oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. We cannot predict future oil and natural gas prices with any degree of certainty. Sustained declines in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of net oil and natural gas reserves that we can produce economically. Any reduction in reserves, including reductions due to price fluctuations, can reduce our borrowing base under our Credit Facility and adversely affect our liquidity and our ability to obtain capital for our acquisition, exploration and development activities. Based on our production for the three months ended March 31, 2019, our gross revenues from oil and natural gas sales would change approximately $1.1 million for each $1.00 change in oil and natural gas liquid prices and $0.4 million for each $0.10 change in natural gas prices.

To mitigate a portion of our exposure to fluctuations in commodity prices, we enter into various types of derivative instruments, which in the past have included commodity price swaps, collars, put options, enhanced swaps and basis protection swaps. We do not apply hedge accounting to any of our derivative instruments. As a result, all gains and losses associated with our derivative contracts are recognized immediately as “Derivative (losses) gains” in the consolidated statements of operations. This can have a significant impact on our results of operations due to the volatility of the underlying commodity prices. Please see “Note 6—Derivative instruments” in “Item 1. Financial Statements” of this report for further discussion of our derivative instruments.

Derivative positions are adjusted in response to changes in prices and market conditions as part of an ongoing dynamic process. We review our derivative positions continuously and if future market conditions change, we may execute a cash settlement with our counterparty, restructure the position, or enter into a new swap that effectively reverses the current position (a counter-swap). The factors we consider in closing or restructuring a position before the settlement date are identical to those reviewed when deciding to enter into the original derivative position.

The fair value of our outstanding derivative instruments at March 31, 2019 was a net liability of $26.9 million. Based on our outstanding derivative instruments as of March 31, 2019, summarized below, a 10% increase in the March 31, 2019, forward curves used to mark-to-market our derivative instruments would have increased our net liability position to $59.9 million, while a 10% decrease would have reduced our net liability position to $4.6 million.

Our outstanding oil derivative instruments as of March 31, 2019, are summarized below:

Period and type of contract	Volume MBbls	Weighted average fixed price per Bbl	
April - June 2019		Swaps	
Oil swaps	624	$	56.34
Oil roll swaps	140	$	0.55
July - September 2019			
Oil swaps	645	$	55.96
Oil roll swaps	120	$	0.46
October - December 2019			
Oil swaps	666	$	55.89
Oil roll swaps	120	$	0.46
January - March 2020			
Oil swaps	504	$	50.47
Oil roll swaps	120	$	0.46
April - June 2020			
Oil swaps	477	$	50.65
Oil roll swaps	110	$	0.42
July - September 2020			
Oil swaps	495	$	50.63
Oil roll swaps	90	$	0.30
October - December 2020			
Oil swaps	531	$	50.49
Oil roll swaps	90	$	0.30
January - March 2021			
Oil swaps	170	$	46.24
Oil roll swaps	90	$	0.30
April - June 2021			
Oil swaps	165	$	45.97
Oil roll swaps	60	$	0.30
July - September 2021			
Oil swaps	184	$	46.64
October - December 2021			
Oil swaps	171	$	46.07

Our outstanding natural gas derivative instruments as of March 31, 2019, are summarized below:

Period and type of contract	Volume BBtu	Weighted average fixed price per MMBtu
April - June 2019		Swaps
Natural gas swaps	3,888	$ 2.85
Natural gas basis swaps	3,888	$ (0.63)
July - September 2019		
Natural gas swaps	3,847	$ 2.85
Natural gas basis swaps	3,164	$ (0.61)
October - December 2019		
Natural gas swaps	3,978	$ 2.85
Natural gas basis swaps	1,830	$ (0.56)
January - March 2020		
Natural gas swaps	1,500	$ 2.75
Natural gas basis swaps	900	$ (0.46)
April - June 2020		
Natural gas swaps	1,500	$ 2.75
Natural gas basis swaps	900	$ (0.46)
July - September 2020		
Natural gas swaps	1,500	$ 2.75
Natural gas basis swaps	900	$ (0.46)
October - December 2020		
Natural gas swaps	1,500	$ 2.75
Natural gas basis swaps	900	$ (0.46)

Our outstanding natural gas liquid derivative instruments as of March 31, 2019 are summarized below:

Period and type of contract	Volume Thousands of Gallons	Weighted average fixed price per gallon
April - June 2019		Swaps
Natural gasoline swaps	1,302	$ 1.39
Propane swaps	2,940	$ 0.74
July - September 2019		
Natural gasoline swaps	1,134	$ 1.39
Propane swaps	2,604	$ 0.74
October - December 2019		
Natural gasoline swaps	1,134	$ 1.39
Propane swaps	2,688	$ 0.74
January - March 2020		
Natural gasoline swaps	1,134	$ 1.39
Propane swaps	2,604	$ 0.74
April - June 2020		
Natural gasoline swaps	756	$ 1.39
Propane swaps	1,680	$ 0.74

Subsequent to March 31, 2019 and through May 7, 2019, we entered into additional derivative contracts, including 195 MBbls of crude oil collars scheduled to settle in the first quarter of 2020 with a weighted average purchased put price of $55.00 per barrel and sold call of $66.42 per barrel, and the following natural gas liquids contracts:

Period and type of contract	Volume Thousands of Gallons		Weighted average fixed price per Gallon
April - June 2019			
Iso butane	168	$	0.72
Natural gasoline	168	$	1.24
N-butane	462	$	0.70
Propane	420	$	0.64
July - September 2019			
Iso butane	546	$	0.72
Natural gasoline	714	$	1.24
N-butane	1,596	$	0.70
Propane	1,554	$	0.64
October - December 2019			
Iso butane	630	$	0.72
Natural gasoline	966	$	1.24
N-butane	1,764	$	0.70
Propane	1,890	$	0.64
January - March 2020			
Iso butane	630	$	0.72
Natural gasoline	882	$	1.24
N-butane	1,722	$	0.70
Propane	1,890	$	0.64

Interest rates. All of the outstanding borrowings under our Credit Facility as of March 31, 2019 are subject to market rates of interest as determined from time to time by the banks. As of March 31, 2019, borrowings bear interest at the Adjusted LIBO Rate, as defined under the Credit Facility, plus the applicable margin, which resulted in a weighted average interest rate of 4.49% on the amount outstanding. Any increases in these rates can have an adverse impact on our results of operations and cash flow. Assuming a constant debt level under our Credit Facility of $325.0 million, equal to our borrowing base at March 31, 2019, the cash flow impact for a 12-month period resulting from a 100 basis point change in interest rates would be $3.3 million.

ITEM 4. *CONTROLS AND PROCEDURES*

Disclosure Controls and procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of March 31, 2019, at the reasonable assurance level.

Changes in Internal control over financial reporting

There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting except for the implementation of changes in our internal controls to ensure we adequately evaluate our contracts and properly assess the impact of the new accounting standard related to leases on our financial statements which was adopted on January 1, 2019.

PART II—OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Please see "Note 10—Commitments and contingencies" in Item 1. Financial Statements of this report for a discussion of our material legal proceedings. In our opinion, there are no other material pending legal proceedings to which we are a party or of which any of our property is the subject. However, due to the nature of our business, certain legal or administrative proceedings may arise from time to time in the ordinary course of business. While the outcome of these legal matters cannot be predicted with certainty, we do not expect them to have a material adverse effect on our financial condition, results of operations or cash flows.

ITEM 1A. RISK FACTORS

Security holders and potential investors in our securities should carefully consider the risk factors in our Annual Report on Form 10-K filed with the SEC on March 14, 2019, together with the information set forth in our subsequent Quarterly Reports on Form 10-Q, current reports on Form 8-K and other materials we file with the SEC.

There have been no material changes to the Risk Factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2018, or our subsequent quarterly reports on Form 10-Q.

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

Period	Total number of shares purchased (1)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs
January 1-31, 2019	—	$ —	N/A	N/A
February 1-28, 2019	33,391	$ 7.15	N/A	N/A
March 1-31, 2019	47,031	$ 4.76	N/A	N/A
Total	80,422	$ 5.75	N/A	N/A

(1) All shares purchases relate to tax withholding and the payment of taxes in connection with vesting of restricted shares issued under our MIP.

ITEM 5. OTHER INFORMATION

Not applicable.

ITEM 6. EXHIBITS

Exhibit No.	Description
3.1*	Third Amended and Restated Certificate of Incorporation of Chaparral Energy, Inc., dated as of March 21, 2017 (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K filed on March 27, 2017).
3.2*	Certificate of Retirement of 7,869,929 shares of Class B Common Stock (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K filed on December 19, 2018).
3.3*	Amended and Restated Bylaws of Chaparral Energy, Inc., dated as of March 21, 2017 (Incorporated by reference to Exhibit 3.2 of the Company's Current Report on Form 8-K filed on March 27, 2017).
4.1*	Registration Rights Agreement, dated as of March 21, 2017, by and among Chaparral Energy, Inc. and the Stockholders named therein (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K filed on March 27, 2017).
4.2*	Warrant Agreement dated as of March 21, 2017, among Chaparral Energy, Inc. and Computershare Inc. as warrant agent (Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K filed on March 27, 2017).
4.3*	Stockholders Agreement, dated as of March 21, 2017, by and among Chaparral Energy, Inc. and the Stockholders named therein (Incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K filed on March 27, 2017).
4.4*	First Amendment to Stockholders Agreement, dated as of March 6, 2018, by and among Chaparral Energy, Inc. and the Stockholders named therein (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K filed on March 9, 2018).
4.5*	Indenture dated June 29, 2018, among the Company, the Guarantors party thereto, and UMB Bank, N.A., as Trustee (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K filed on July 2, 2018).
4.6*	Form of 8.750% Senior Note due 2023 (Incorporated by reference to Exhibit A of Exhibit 4.1 of the Company's Current Report on Form 8-K filed on July 2, 2018).
10.1*†	Separation and Release Agreement, dated February 14, 2019, by and between Chaparral Energy, Inc. and Joseph O. Evans (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on February 15, 2019).
10.2	Third Amendment to Tenth Restated Credit Agreement, dated as of May 2, 2019, among Chaparral Energy, Inc., as borrower, Royal Bank of Canada, as administrative agent and issuing bank, and the additional lenders party thereto.
31.1	Certification by Principal Executive Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act.

Exhibit No.	Description
31.2	Certification by Principal Financial Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act.
32.1	Certification by Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification by Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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 Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* Incorporated by reference

† Management contract or compensatory plan or arrangement

** The schedules and exhibits to this agreement have been omitted from this filing pursuant to Item 601(b)(2) of Regulation S-K. Chaparral Energy, Inc. will furnish copies of such schedules to the SEC upon request.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CHAPARRAL ENERGY, INC.

By:	/s/ K. Earl Reynolds
Name:	K. Earl Reynolds
Title:	*Chief Executive Officer*
	(Principal Executive Officer)
By:	/s/ Scott Pittman
Name:	Scott Pittman
Title:	*Chief Financial Officer and Senior Vice President*
	(Principal Financial Officer and Principal Accounting Officer)

Date: May 9, 2019

EXHIBIT 10.2

THIRD AMENDMENT TO TENTH RESTATED CREDIT AGREEMENT

This Third Amendment to Tenth Restated Credit Agreement (this "Third Amendment"), dated as of May 2, 2019 and effective as of March 31, 2019 (the "Third Amendment Effective Date"), is by and among **CHAPARRAL ENERGY, INC.**, a Delaware corporation (the "Borrower"), each Guarantor party hereto (the "Guarantors"), **ROYAL BANK OF CANADA**, as Administrative Agent ("Administrative Agent"), and each of the Lenders party hereto.

W I T N E S S E T H:

WHEREAS, the Borrower, Administrative Agent, the other Agents party thereto, Issuing Bank, and the Lenders are parties to that certain Tenth Restated Credit Agreement dated as of December 21, 2017 (as amended, restated, or otherwise modified prior to the date hereof, the "Credit Agreement") (unless otherwise defined herein, all terms used herein with their initial letter capitalized shall have the meanings given such terms in the Credit Agreement);

WHEREAS, pursuant to the Credit Agreement, the Lenders have made Loans to the Borrower; and

WHEREAS, the parties hereto desire to enter into this Third Amendment to (i) amend certain terms of the Credit Agreement as more specifically set forth herein and (ii) evidence the reaffirmation of the Borrowing Base at $325,000,000, in each case, to be effective on the Third Amendment Effective Date.

NOW THEREFORE, for and in consideration of the mutual covenants and agreements herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged and confessed, the Borrower, Guarantors, Administrative Agent and the Lenders party hereto hereby agree as follows:

Section 1. Amendments. In reliance on the representations, warranties, covenants and agreements contained in this Third Amendment, and subject to the satisfaction of the conditions precedent set forth in Section 3 hereof, the Credit Agreement is hereby amended effective as of the Third Amendment Effective Date in the manner provided in this Section 1.

1.1 Amended and Restated Definitions. The following definitions in Section 1.02 of the Credit Agreement are hereby amended and restated in their respective entireties to read in full as follows:

"EBITDAX" means, for any period, the sum of Consolidated Net Income for such period plus the following expenses or charges to the extent deducted from Consolidated Net Income in such period: (a) interest, (b) income and franchise taxes, (c) depreciation, depletion, amortization, exploration expenses and other noncash charges (including (i) non-cash losses resulting from mark-to-market in respect of Swap Agreements (including those resulting from the requirements of ASC Topic 815) and (ii) non-cash losses from the adoption of fresh start accounting in connection with the consummation of the Plan of Reorganization), (d) losses from asset dispositions (other than Hydrocarbons produced in the ordinary course of business), (e) actual fees and transaction costs incurred by the Credit Parties in connection with the Bankruptcy Proceedings and the closing of this Agreement and the Transactions occurring on or about the Effective Date (other than, for the avoidance of doubt, severance payments and consulting fees paid to former officers and employees), (f) severance payments and consulting fees paid to former officers and employees not later than 10 days following the consummation of the Plan of Reorganization in connection with the Bankruptcy Proceedings in an amount not to exceed $4,000,000, (g) charges, reserves and expenses incurred on or before December 31, 2017 in connection with cost savings initiatives in an amount not to exceed $3,000,000, (h) any fees and expenses or charges incurred in connection with the implementation of fresh start accounting in an amount not to exceed $1,000,000, (i) to the extent incurred on or after January 1, 2019, any severance payments, retirement payments, consulting fees, and/or related charges paid or incurred in connection with any retirement, severance, or departure of officers or former officers in an amount not to exceed $4,000,000 in the aggregate during any Reference Period, and (j) actual fees and transaction costs incurred prior to the Effective Date in connection with the sale by certain Credit Parties of certain Oil and Gas Properties pursuant to that certain Asset Purchase and Sale Agreement, dated as of October 13, 2017, among Chaparral Energy, L.L.C., Chaparral CO2, L.L.C., Chaparral Real Estate, L.L.C. and Perdure Petroleum, LLC (including, without limitation, legal, accounting and financial advisory fees, title and environmental due diligence costs, employee retention, severance, or relocation expenses, costs and expenses related to the acceleration of long-term employee incentive awards, and contract termination and restructuring costs) in an amount not to exceed $4,000,000, minus all gains from asset dispositions (other than Hydrocarbons produced in the ordinary course of business) and all noncash income, in each case to the extent added to Consolidated Net Income in such period. For the purposes of calculating EBITDAX (including any component thereof) for any period of four (4) consecutive fiscal quarters (each, a "Reference Period") pursuant to any determination of the financial ratio contained in Section 9.01(a), if at any time during such Reference Period the Borrower or any Consolidated Restricted Subsidiary shall have made any Material Disposition or Material Acquisition, the EBITDAX for such Reference Period shall be calculated after giving pro forma effect thereto as if such Material Disposition or Material Acquisition had occurred on the first day of such Reference Period (such calculations to be determined by a Financial Officer in good faith and reasonably acceptable to the Administrative Agent).

"Interest Period" means with respect to any Eurodollar Borrowing, the period commencing on the date of such Borrowing and ending on the numerically corresponding day in the calendar month that is one, two, three or six months or, with the consent of each Lender, twelve months (or such period of less than one month as may be consented to by each applicable Lender), thereafter, as the Borrower may elect; *provided* that (a) if any Interest Period would end on a day other than a Business Day, such Interest Period shall be extended to the next succeeding Business

Day unless such next succeeding Business Day would fall in the next calendar month, in which case such Interest Period shall end on the next preceding Business Day and (b) any Interest Period pertaining to a Eurodollar Borrowing that commences on the last Business Day of a calendar month (or on a day for which there is no numerically corresponding day in the last calendar month of such Interest Period) shall end on the last Business Day of the last calendar month of such Interest Period. For purposes hereof, the date of a Borrowing initially shall be the date on which such Borrowing is made and thereafter shall be the effective date of the most recent conversion or continuation of such Borrowing.

"Loan Documents" means this Agreement, the First Amendment, the Second Amendment, the Third Amendment, the Notes, the Letter of Credit Agreements, the Letters of Credit, the Engagement Letters and the Security Instruments.

1.2 Additional Definitions. Section 1.02 of the Credit Agreement is hereby amended to add the following definition to such Section in appropriate alphabetical order:

"Third Amendment" means that certain Third Amendment to Tenth Restated Credit Agreement dated as of May 2, 2019, and effective as of March 31, 2019, among the Borrower, the Guarantors party thereto, the Administrative Agent and the Lenders party thereto.

"Third Amendment Effective Date" means March 31, 2019.

SECTION 2. Borrowing Base. In reliance on the covenants and agreements contained in this Third Amendment, and subject to the satisfaction of the conditions precedent set forth in Section 3 hereof, Administrative Agent and the Required Lenders agree that the Borrowing Base shall be and hereby is reaffirmed at $325,000,000, effective as of the Third Amendment Effective Date and continuing until the next Scheduled Redetermination, Interim Redetermination or other redetermination or adjustment of the Borrowing Base thereafter. The Borrower, the Administrative Agent, and the Lenders acknowledge that the reaffirmation of the Borrowing Base provided for in this Section 2 constitutes the Scheduled Redetermination intended to be effective on, or as promptly as reasonably practicable after, May 1, 2019, as referenced in Section 2.07(b) of the Credit Agreement, and that this Third Amendment constitutes the New Borrowing Base Notice with respect to such Scheduled Redetermination.

SECTION 3. Conditions Precedent to this Third Amendment. The effectiveness of this Third Amendment is subject to the satisfaction or waiver of each of the following conditions precedent:

3.1 Counterparts. Administrative Agent shall have received counterparts hereof duly executed by the Borrower, each Guarantor and Lenders constituting Required Lenders.

3.2 Fees and Expenses. Administrative Agent shall have received all fees and other amounts due and payable on or prior to the Third Amendment Effective Date in accordance with

Section 12.03 of the Credit Agreement and, to the extent invoiced at least one Business Day prior to the Third Amendment Effective Date, Section 5.3 hereof.

3.3 Other Documents. Administrative Agent shall have been provided with such other documents, instruments and agreements, and the Borrower shall have taken such actions, as Administrative Agent or counsel to Administrative Agent may reasonably require in connection with this Third Amendment and the transactions contemplated hereby.

SECTION 4. Representations and Warranties of the Credit Parties. To induce the Lenders and Administrative Agent to enter into this Third Amendment, each Credit Party hereby represents and warrants to the Lenders and Administrative Agent as follows:

4.1 Reaffirm Existing Representations and Warranties. Each representation and warranty of each Credit Party contained in the Credit Agreement and the other Loan Documents is true and correct in all material respects on the date hereof and will be true and correct in all material respects after giving effect to the amendments set forth in Section 1 hereof, except to the extent that (a) any such representation and warranty is expressly limited to an earlier date, in which case such representation and warranty is and will be true and correct in all material respects as of such specified earlier date and (b) any such representation and warranty is expressly qualified by materiality or by reference to Material Adverse Effect, in which case such representation and warranty (as so qualified) is and will be true and correct in all respects.

4.2 Due Authorization. The execution, delivery and performance by each Credit Party that is a party hereto of this Third Amendment are within such Credit Party's corporate, limited liability company, or partnership powers (as applicable) and have been duly authorized by all necessary corporate, limited liability company, or partnership action (as applicable).

4.3 Validity and Enforceability. This Third Amendment constitutes the valid and binding obligation of each Credit Party that is a party hereto, enforceable against such Credit Party in accordance with its terms, subject to applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting creditors' rights generally and subject to general principles of equity, regardless of whether considered in a proceeding in equity or at law.

4.4 No Default, Event of Default or Borrowing Base Deficiency. No Default, Event of Default or Borrowing Base Deficiency has occurred and is continuing.

SECTION 5. Miscellaneous.

5.1 Reaffirmation of Loan Documents and Liens. Any and all of the terms and provisions of the Credit Agreement and the other Loan Documents shall, except as amended or otherwise modified hereby, remain in full force and effect. Except to the extent expressly set forth herein, the amendments contemplated hereby shall not limit or impair any Liens securing the Indebtedness, each of which are hereby ratified and affirmed to secure the Indebtedness as such Indebtedness may be increased or otherwise affected by this Third Amendment.

5.2 Parties in Interest. All of the terms and provisions of this Third Amendment shall bind and inure to the benefit of the parties hereto and their respective successors and permitted assigns.

5.3 Legal Expenses. The Borrower hereby agrees to pay, as and when required by Section 12.03 of the Credit Agreement, all reasonable and documented out-of-pocket fees and expenses of counsel to Administrative Agent incurred by Administrative Agent in connection with the preparation, negotiation and execution of this Third Amendment and all related documents.

5.4 Counterparts. This Third Amendment may be executed in counterparts (and by the different parties hereto on different counterparts), each of which shall constitute an original, but all of which when taken together shall constitute a single contract. Delivery of an executed counterpart of a signature page of this Third Amendment by fax or other electronic transmission (e.g., .pdf) shall be effective as delivery of a manually executed counterpart of this Third Amendment.

5.5 Complete Agreement. THIS THIRD AMENDMENT, THE CREDIT AGREEMENT AND THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT AMONG THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN OR AMONG THE PARTIES.

5.6 Headings. The headings, captions and arrangements used in this Third Amendment are, unless specified otherwise, for convenience only and shall not be deemed to limit, amplify or modify the terms of this Third Amendment, nor affect the meaning thereof.

5.7 Effectiveness. This Third Amendment shall be effective automatically and without necessity of any further action by the Borrower, Administrative Agent or Lenders when counterparts hereof have been executed by the Borrower, each Guarantor, Administrative Agent and Lenders constituting Required Lenders, and all conditions to the effectiveness hereof set forth herein have been satisfied. Administrative Agent shall notify the Borrower and the Lenders of the effectiveness of this Amendment, and such notice shall be conclusive and binding.

5.8 Governing Law. This Third Amendment shall be governed by, and construed in accordance with, the laws of the State of New York.

[*Signature pages follow*]

IN WITNESS WHEREOF, the parties hereto have caused this Third Amendment to be duly executed as of the day and year first above written.

BORROWER:

CHAPARRAL ENERGY, INC.,
a Delaware corporation

By: /s/ K. Earl Reynolds
Name: K. Earl Reynolds
Title: Chief Executive Officer

GUARANTORS:

CHAPARRAL ENERGY, L.L.C., an Oklahoma limited liability company

By: /s/ K. Earl Reynolds
Name: K. Earl Reynolds
Title: Chief Executive Officer

CHAPARRAL RESOURCES, L.L.C., an Oklahoma limited liability company

By: /s/ K. Earl Reynolds
Name: K. Earl Reynolds
Title: Chief Executive Officer

CHAPARRAL CO2, L.L.C., an Oklahoma limited liability company

By: /s/ K. Earl Reynolds
Name: K. Earl Reynolds
Title: Chief Executive Officer

CEI ACQUISITION, L.L.C., a Delaware limited liability company

By: /s/ K. Earl Reynolds
Name: K. Earl Reynolds
Title: Chief Executive Officer

CEI PIPELINE, L.L.C., a Texas limited liability company

By: /s/ K. Earl Reynolds
Name: K. Earl Reynolds
Title: Chief Executive Officer

CHAPARRAL REAL ESTATE, L.L.C., an Oklahoma limited liability company

By: /s/ K. Earl Reynolds
Name: K. Earl Reynolds
Title: Chief Executive Officer

GREEN COUNTRY SUPPLY, INC., an Oklahoma corporation

By: /s/ K. Earl Reynolds
Name: K. Earl Reynolds
Title: Chief Executive Officer

CHAPARRAL EXPLORATION, L.L.C., a Delaware limited liability company

By: /s/ K. Earl Reynolds
Name: K. Earl Reynolds
Title: Chief Executive Officer

ROADRUNNER DRILLING, L.L.C., an Oklahoma limited liability company

By: /s/ K. Earl Reynolds
Name: K. Earl Reynolds
Title: Chief Executive Officer

CHAPARRAL BIOFUELS, L.L.C., an Oklahoma limited liability company

By: /s/ K. Earl Reynolds
Name: K. Earl Reynolds
Title: Chief Executive Officer

ADMINISTRATIVE AGENT:	**ROYAL BANK OF CANADA**
	By: /s/ Rodica Dutka Name: Rodica Dutka Title: Manager, Agency Services Group

LENDER:	**ROYAL BANK OF CANADA**
	By: /s/ Emilee Scott Name: Emilee Scott Title: Authorized Signatory

LENDER: **CAPITAL ONE, NATIONAL ASSOCIATION**

By: /s/ Cameron Breitenbach
Name: Cameron Breitenbach
Title: Vice President

LENDER: **NATIXIS, NEW YORK BRANCH**

By: /s/ Valerie Du Mars
Name: Valerie Du Mars
Title: Managing Director

By: /s/ Jonathan Cohen
Name: Jonathan Cohen
Title: Executive Director

LENDER: **KEYBANK NATIONAL ASSOCIATION**

By: /s/ David M. Bornstein
Name: David M. Bornstein
Title: Senior Vice President

LENDER: **SOCIÉTÉ GÉNÉRALE**

By: /s/ Max Sonnonstine
Name: Max Sonnonstine
Title: Director

LENDER: **ABN AMRO CAPITAL USA LLC**

By: /s/ Darrel Holley
Name: Darrel Holley
Title: Managing Director

By: /s/ David Montgomery
Name: David Montgomery
Title: Managing Director

LENDER: **CANADIAN IMPERIAL BANK OF COMMERCE, NEW YORK BRANCH**

By: /s/ Donavan C. Broussard
Name: Donavan C. Broussard
Title: Authorized Signatory

By: /s/ Megan Larson
Name: Megan Larson
Title: Authorized Signatory

LENDER: **COMPASS BANK**

By: /s/ Mark H. Wolf
Name: Mark H. Wolf
Title: Senior Vice President

LENDER:	**CREDIT AGRICOLE CORPORATE AND INVESTMENT BANK**

By: /s/ Michael Willis
Name: Michael Willis
Title: Managing Director

By: /s/ Parker Laville
Name: Parker Laville
Title: Managing Director

LENDER: **THE HUNTINGTON NATIONAL BANK**

By: /s/ Gregory R. Ryan
Name: Gregory R. Ryan
Title: Director, Energy Banking

LENDER:	**THE TORONTO-DOMINION BANK, NEW YORK BRANCH**

By: /s/ Michael Borowiecki
Name: Michael Borowiecki
Title: Authorized Signatory

LENDER: **BANK OF AMERICA, N.A.**

By: /s/ Raza Jafferi
Name: Raza Jafferi
Title: Director

LENDER: **EAST WEST BANK**

By: /s/ Reed Thompson
Name: Reed Thompson
Title: Senior Vice President

LENDER: **COMERICA BANK**

By: /s/ Mackenzie Dold
Name: Mackenzie Dold
Title: Vice President

EXHIBIT 31.1

CERTIFICATION

I, K. Earl Reynolds, Chief Executive Officer of Chaparral Energy, Inc., certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Chaparral Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;
    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
6. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
7. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 9, 2019

/s/ K. Earl Reynolds

K. Earl Reynolds

Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Scott Pittman, Chief Financial Officer of Chaparral Energy, Inc., certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Chaparral Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;
    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
6. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
7. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 9, 2019

/s/ Scott Pittman

Scott Pittman

Chief Financial Officer and Senior Vice President

EXHIBIT 32.1

CERTIFICATION OF PERIODIC REPORT

I, K. Earl Reynolds, Chief Executive Officer of Chaparral Energy Inc. (the “Company”), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Quarterly Report on Form 10-Q of the Company for the period ended March 31, 2019 (the “Report”) fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

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

Date: May 9, 2019

/s/ K. Earl Reynolds

K. Earl Reynolds

Chief Executive Officer

EXHIBIT 32.2

CERTIFICATION OF PERIODIC REPORT

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

(1) the Quarterly Report on Form 10-Q of the Company for the period ended March 31, 2019 (the "Report") fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

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

Date: May 9, 2019

/s/ Scott Pittman

Scott Pittman

Chief Financial Officer and Senior Vice President