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 September 30, 2018

or

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

Commission File Number: 001-37995

Jagged Peak Energy Inc.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**81-3943703** (IRS Employer Identification Number)
1401 Lawrence Street, Suite 1800 **Denver, Colorado** (Address of principal executive offices)	**80202** (Zip Code)

(720) 215-3700
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§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, a 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 ☒

The registrant had 213,186,919 shares of common stock outstanding at November 2, 2018.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in the oil and natural gas industry:

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or NGLs.

Boe. One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

Boe/d. One Boe per day.

Completion. The installation of permanent equipment for production of oil, natural gas or NGLs or, in the case of a dry well, reporting to the appropriate authority that the well has been abandoned.

Differential. An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

MBbl. One thousand barrels of crude oil, condensate or NGLs.

MBoe. One thousand Boe.

Mcf. One thousand cubic feet of natural gas.

Mcf/d. One Mcf per day.

MMBbl. One million barrels of crude oil, condensate or NGLs.

MMcf. One million cubic feet of natural gas.

MMcf/d. One MMcf per day.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be. For example, an owner who has 50% interest in 100 acres owns 50 net acres. Likewise, an owner who has a 50% working interest in a well has a 0.50 net well.

NGL(s). Natural gas liquid(s). Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.

NYMEX. The New York Mercantile Exchange.

Proved properties. Properties with proved reserves.

Realized price. The cash market price less all expected quality, transportation and demand adjustments.

Spud. Commenced drilling operations on an identified location.

Unproved properties. Lease acreage with no proved reserves.

Working interest. The right granted to the lessee of a property to develop and produce and own oil, natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

Workover. Operations on a producing well to restore or increase production.

WTI. West Texas Intermediate. A market index price for oil that is widely quoted by financial markets.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this Form 10-Q includes “forward-looking statements.” All statements, other than statements of historical fact included in or incorporated by reference into this Quarterly Report on Form 10-Q, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management’s current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2017, in “Part II. Other Information - Item 1A. Risk Factors” of this Quarterly Report, and in “Item 8.01, Other Events” in our Current Report on Form 8-K filed with the Securities and Exchange Commission on April 23, 2018.

Forward-looking statements include statements about:

- our business strategy;
- our reserves;
- our drilling prospects, inventories, projects and programs;
- our intention to replace the reserves we produce through drilling and property acquisitions;
- our financial strategy, liquidity and capital required for our drilling program, including our assessment of the sufficiency of our liquidity to fund our capital program and the amount and allocation of our capital program in 2018;
- our expected timing of the exchange offer of our senior notes issued in May 2018;
- our expected noncash compensation expenses;
- our expected pricing and realized oil, natural gas and NGL prices;
- the timing and amount of our future production of oil, natural gas and NGLs;
- our future drilling plans, including the number of wells anticipated to be brought online in 2018;
- government regulations and our ability to obtain permits and governmental approvals;
- our pending legal or environmental matters;
- our marketing of oil, natural gas and NGLs;
- our leasehold or business acquisitions;
- our costs of developing our properties, including our capital budget;
- our hedging strategy and results;
- general economic conditions;
- uncertainty regarding our future operating results; and
- our plans, objectives, expectations and intentions contained in this quarterly report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the development, production, gathering and sale of oil, natural gas and NGLs. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures and the other risks described under “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2017, in “Part II. Other Information - Item 1A. Risk Factors” of this Quarterly Report, and in “Item 8.01, Other Events” in our Current Report on Form 8-K filed with the Securities and Exchange Commission on April 23, 2018.

Reserve engineering is a process of estimating underground accumulations of hydrocarbons 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 could impact our strategy and change the schedule of any further 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 the risks or uncertainties described in this Form 10-Q occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this Form 10-Q are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Quarterly Report on Form 10-Q.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

JAGGED PEAK ENERGY INC.
CONSOLIDATED AND COMBINED BALANCE SHEETS
(Unaudited)
(in thousands, except share data)

	September 30, 2018	December 31, 2017
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 93,939	$ 9,523
Accounts receivable	78,270	50,734
Derivative instruments	19,991	—
Other current assets	3,124	806
Total current assets	195,324	61,063
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, successful efforts method	1,760,690	1,195,831
Accumulated depletion	(325,567)	(166,592)
Total oil and gas properties, net	1,435,123	1,029,239
Other property and equipment, net	10,257	9,708
Total property and equipment, net	1,445,380	1,038,947
OTHER NONCURRENT ASSETS		
Unamortized debt issuance costs	3,842	3,273
Derivative instruments	719	26
Other assets	120	119
Total noncurrent assets	4,681	3,418
TOTAL ASSETS	$ 1,645,385	$ 1,103,428
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 14,033	$ 382
Accrued liabilities	154,540	132,311
Derivative instruments	104,490	41,782
Total current liabilities	273,063	174,475
LONG-TERM LIABILITIES		
Long-term debt	488,972	155,000
Derivative instruments	45,792	11,095
Asset retirement obligations	1,427	811
Deferred income taxes	72,680	57,943
Other long-term liabilities	4,522	4,759
Total long-term liabilities	613,393	229,608
Commitments and contingencies		
STOCKHOLDERS' EQUITY		
Preferred stock, $0.01 par value; 50,000,000 shares authorized, none issued	—	—
Common stock, $0.01 par value; 1,000,000,000 shares authorized, 213,180,881 shares issued at September 30, 2018; 212,930,655 shares issued at December 31, 2017	2,132	2,129
Additional paid-in capital	854,143	773,674
Accumulated deficit	(97,346)	(76,458)
Total stockholders' equity	758,929	699,345
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,645,385	$ 1,103,428

The accompanying Notes are an integral part of these unaudited consolidated and combined financial statements.

JAGGED PEAK ENERGY INC.
CONSOLIDATED AND COMBINED STATEMENTS OF OPERATIONS
(Unaudited)
(in thousands, except per share amounts)

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
REVENUES				
Oil sales	$ 141,598	$ 62,585	$ 410,935	$ 147,738
Natural gas sales	2,552	2,939	7,765	5,697
NGL sales	10,814	4,860	23,721	9,041
Other operating revenues	414	67	686	414
Total revenues	155,378	70,451	443,107	162,890
OPERATING EXPENSES				
Lease operating expenses	11,184	5,184	31,390	10,684
Gathering and processing expenses	—	1,357	—	2,404
Production and ad valorem taxes	9,517	4,739	26,437	10,916
Exploration	23	6	24	14
Depletion, depreciation, amortization and accretion	57,660	30,851	160,552	67,224
Impairment of unproved oil and natural gas properties	—	257	53	365
General and administrative expenses (including equity-based compensation of $2,614 and $11,903 for the three months ended September 30, 2018 and 2017, respectively, and $80,671 and $431,642 for the nine months ended September 30, 2018 and 2017, respectively)	12,321	17,733	109,471	449,504
Other operating expenses	19	41	65	223
Total operating expenses	90,724	60,168	327,992	541,334
INCOME (LOSS) FROM OPERATIONS	64,654	10,283	115,115	(378,444)
OTHER INCOME (EXPENSE)				
Gain (loss) on commodity derivatives	(96,516)	(27,693)	(110,426)	15,922
Interest expense, net	(8,256)	(467)	(17,095)	(1,610)
Gain on sale of assets	6,225	—	6,225	—
Other, net	12	60	30	474
Total other income (expense)	(98,535)	(28,100)	(121,266)	14,786
INCOME (LOSS) BEFORE INCOME TAX	(33,881)	(17,817)	(6,151)	(363,658)
Income tax expense (benefit)	(7,315)	(2,598)	14,737	101,039
NET INCOME (LOSS)	(26,566)	(15,219)	(20,888)	(464,697)
Less: Net loss attributable to Jagged Peak Energy LLC (predecessor)	—	—	—	(375,476)
NET INCOME (LOSS) ATTRIBUTABLE TO JAGGED PEAK ENERGY INC. STOCKHOLDERS	$ (26,566)	$ (15,219)	$ (20,888)	$ (89,221)
Net income (loss) attributable to Jagged Peak Energy Inc. Stockholders per common share:				
Basic	$ (0.12)	$ (0.07)	$ (0.10)	$ (0.42)
Diluted	$ (0.12)	$ (0.07)	$ (0.10)	$ (0.42)
Weighted average common shares outstanding:				
Basic	213,180	212,931	213,109	212,933
Diluted	213,180	212,931	213,109	212,933

The accompanying Notes are an integral part of these unaudited consolidated and combined financial statements.

JAGGED PEAK ENERGY INC.
CONSOLIDATED AND COMBINED STATEMENT OF CHANGES IN EQUITY
(Unaudited)
(in thousands)

	Common Stock		Additional Paid-in Capital	Accumulated Deficit	Total Stockholders' Equity
	Shares	Amount			
BALANCE AT DECEMBER 31, 2017	212,931	$ 2,129	$ 773,674	$ (76,458)	$ 699,345
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	250	3	(202)	—	(199)
Equity-based compensation	—	—	80,671	—	80,671
Net income (loss)	—	—	—	(20,888)	(20,888)
BALANCE AT SEPTEMBER 30, 2018	213,181	$ 2,132	$ 854,143	$ (97,346)	$ 758,929

The accompanying Notes are an integral part of these unaudited consolidated and combined financial statements.

JAGGED PEAK ENERGY INC.
CONSOLIDATED AND COMBINED STATEMENTS OF CASH FLOWS
(Unaudited)
(in thousands)

	Nine Months Ended September 30, 2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$ (20,888)	$ (464,697)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion expense	160,552	67,224
Impairment of unproved oil and natural gas properties	53	365
Amortization of debt issuance costs	1,753	407
Deferred income taxes	14,737	101,039
Equity-based compensation	80,671	431,642
(Gain) loss on commodity derivatives	110,426	(15,922)
Net cash receipts (payments) on settled derivatives	(33,705)	3,691
(Gain) on sale of assets	(6,225)	—
Other	(234)	(123)
Change in operating assets and liabilities:		
Accounts receivable and other current assets	(29,854)	(27,292)
Other assets	—	(3)
Accounts payable and accrued liabilities	40,461	9,097
Net cash provided by operating activities	317,747	105,428
CASH FLOWS FROM INVESTING ACTIVITIES		
Leasehold and acquisition costs	(18,854)	(60,627)
Development of oil and natural gas properties	(551,059)	(349,176)
Other capital expenditures	(3,245)	(3,332)
Proceeds from sale of oil and natural gas properties	8,377	—
Net cash used in investing activities	(564,781)	(413,135)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from senior notes	500,000	—
Proceeds from credit facility	165,000	45,000
Repayment of credit facility	(320,000)	(142,000)
Debt issuance costs	(13,350)	(1,441)
Proceeds from issuance of common stock in initial public offering, net of underwriting fees	—	401,625
Costs relating to initial public offering	—	(3,216)
Employee tax withholding for settlement of equity compensation awards	(200)	(88)
Net cash provided by financing activities	331,450	299,880
NET CHANGE IN CASH AND CASH EQUIVALENTS	84,416	(7,827)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	9,523	11,727
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 93,939	$ 3,900
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION		
Interest paid, net of capitalized interest	$ 4,009	$ 1,234
Cash paid for income taxes	—	—
SUPPLEMENTAL DISCLOSURE OF NONCASH INVESTING ACTIVITIES		
Accrued capital expenditures	$ 100,780	$ 102,031
Asset retirement obligations	567	488

The accompanying Notes are an integral part of these unaudited consolidated and combined financial statements.

JAGGED PEAK ENERGY INC.

Notes to Consolidated and Combined Financial Statements
(Unaudited)

Note 1—Organization, Operations and Basis of Presentation

Organization and Operations

Jagged Peak Energy Inc. (either individually or together with its subsidiary, as the context requires, "Jagged Peak" or the "Company") is an independent oil and natural gas company focused on the acquisition and development of unconventional oil and associated liquids-rich natural gas reserves in the southern Delaware Basin; the Delaware Basin is a sub-basin of the Permian Basin of West Texas. The Company's acreage is located on large, contiguous blocks in the adjacent counties of Winkler, Ward, Reeves and Pecos, with significant oil-in-place within multiple stacked hydrocarbon-bearing formations.

Corporate Reorganization and Initial Public Offering

Jagged Peak is a Delaware corporation formed in September 2016, as a wholly owned subsidiary of Jagged Peak Energy LLC ("JPE LLC"), a Delaware limited liability company formed in April 2013. JPE LLC was formed by an affiliate of Quantum Energy Partners ("Quantum") and former members of Jagged Peak's management team. Jagged Peak was formed to become the holding company of JPE LLC in connection with Jagged Peak's initial public offering (the "IPO").

Immediately prior to the IPO, a corporate reorganization (the "corporate reorganization") took place whereby JPE LLC became a wholly owned subsidiary of Jagged Peak. As all power and authority to control the core functions of Jagged Peak and JPE LLC were, and continue to be, controlled by Quantum, the corporate reorganization was treated as a reorganization of entities under common control and the results of JPE LLC have been consolidated and combined for all periods.

On January 27, 2017, the Company initiated its IPO of 31,599,334 shares of common stock to the public, which included 3,266,000 shares sold by the selling stockholders. The stock was priced at $15.00 per share and the Company received net proceeds of approximately $397.0 million after deducting offering expenses and underwriting discounts and commissions. The Company did not receive any proceeds from the sale of the shares by the selling stockholders.

Additional background on the Company and its IPO, along with details of the ownership of the Company are available in the Company's Annual Report on Form 10-K for the year ended December 31, 2017 (the "2017 Form 10-K").

Basis of Presentation

The accompanying unaudited consolidated and combined financial statements include the accounts of Jagged Peak and JPE LLC, and have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information, and should be read in conjunction with the financial statements, summary of significant accounting policies and footnotes included in the 2017 Form 10-K. Accordingly, certain disclosures required by GAAP and normally included in Annual Reports on Form 10-K have been condensed or omitted from this report; however, except as disclosed herein, there has been no material change in the information disclosed in the notes to consolidated and combined financial statements included in the 2017 Form 10-K. All significant intercompany and intra-company balances and transactions have been eliminated.

It is the opinion of management that all adjustments, consisting of normal recurring adjustments considered necessary for a fair presentation of interim financial information, have been included. The Company has no items of other comprehensive income or loss; therefore, its net income or loss is identical to its comprehensive income or loss. Operating results for the periods presented are not necessarily indicative of expected results for the full year because of the impact of fluctuations in prices received for oil, natural gas and NGLs, expected production increases due to development activities, natural production declines, the uncertainty of exploration and development drilling results, the fair value of derivative instruments and other factors.

The unaudited consolidated and combined financial statements for periods prior to January 27, 2017 reflect the historical results of JPE LLC, other than the equity-based compensation expense and deferred tax expense, as further described in Note 5, *Equity-based Compensation*, and Note 7, *Income Taxes*, respectively.

Note 2—Significant Accounting Policies and Related Matters

Significant Accounting Policies

The significant accounting policies followed by the Company are set forth in Note 2, *Significant Accounting Policies and Related Matters*, to the Company's consolidated and combined financial statements in its 2017 Form 10-K, and are supplemented by the notes to the consolidated and combined financial statements in this Quarterly Report on Form 10-Q. Any new accounting policies or updates to existing accounting policies as a result of new accounting pronouncements have been included in these notes to the consolidated and combined financial statements.

Use of Estimates

In the course of preparing the consolidated and combined financial statements, management makes various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenues and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Estimates made in preparing these consolidated and combined financial statements include, among other things, (1) estimates of oil and natural gas reserve quantities, which impact depreciation, depletion and amortization and impairment of proved oil and natural gas properties, (2) accrued operating and capital costs, (3) estimates of timing and costs used in calculating asset retirement obligations, (4) estimates of the fair value of equity-based compensation, (5) assumptions and estimates used in the calculation of fair value, (6) estimates of deferred income taxes and (7) estimates and assumptions used in the disclosure of commitments and contingencies. Changes in these estimates and assumptions could have a significant impact on results in future periods.

Revenue Recognition

On January 1, 2018, the Company adopted Accounting Standards Codification Topic 606, *Revenue from Contracts with Customers*, ("ASC 606") using the modified retrospective approach, which only applied to contracts that were in effect as of the date of adoption. The adoption did not require an adjustment to opening retained earnings for the cumulative effect adjustment and did not impact the Company's previously reported results of operations, nor its ongoing consolidated and combined balance sheets, statements of cash flow or statement of changes in equity.

Under ASC 606, oil, natural gas and NGL sales revenues are recognized when control of the product is transferred to the customer, the performance obligations under the terms of the contracts with customers are satisfied and collectability is reasonably assured. All of the Company's oil, natural gas and NGL sales are made under contracts with customers. The performance obligations for the Company's contracts with customers are satisfied at a point in time through the delivery of oil and natural gas to its customers. Accordingly, the Company's contracts do not give rise to contract assets or liabilities. The Company typically receives payment for oil, natural gas and NGL sales within 30 days of the month of delivery. The Company's contracts for oil, natural gas and NGL sales are standard industry contracts that include variable consideration based on the monthly index price and adjustments that may include counterparty-specific provisions related to volumes, price differentials, discounts and other adjustments and deductions.

Under the Company's current gas processing contracts, it delivers natural gas to a purchaser at or near the wellhead. For these contracts, the Company has concluded the purchaser is the customer, and as such, the Company recognizes natural gas and NGL revenues based on the net amount of proceeds it receives from the purchaser.

The Company's product types are as follows:

Oil Sales. Under the Company's oil sales contracts, the Company generally sells oil to the purchaser at or near the wellhead, and collects a contractually agreed upon index price, net of pricing and gathering and transportation differentials. The Company transfers control of the product to the purchaser at or near the wellhead and recognizes revenue based on the net price received.

Natural Gas and NGL Sales. Under the Company's natural gas sales contracts, the Company delivers and transfers control of natural gas to the purchaser at delivery points at or near the wellhead. The purchaser gathers and processes the natural gas and sells the resulting residue gas and NGLs. The Company receives its contractual portion of the proceeds for the sale of the residue gas and NGLs at an agreed upon index price, net of pricing differentials and applicable selling expenses including gathering, processing and fractionation costs. The Company recognizes revenue at the net price when control transfers to the purchaser.

The Company does not disclose the value of unsatisfied performance obligations for (i) contracts with an original expected length of one year or less and (ii) contracts for which the variable consideration is allocated entirely to a wholly unsatisfied performance obligation, as allowed under ASC 606. Under the Company's oil, natural gas and NGL sales contracts, each unit of product delivered to the customer represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Disaggregation of Revenue

The Company's oil, natural gas and NGL sales revenues represent substantially all of its revenues, and are derived from the sale of oil, natural gas and NGL production within the Permian Basin. The Company believes the disaggregation of revenues into the three product types of oil sales, natural gas sales and NGL sales, as seen on the consolidated and combined statements of operations, is an appropriate level of detail for its primary activity.

Accounts Receivable

At September 30, 2018 and December 31, 2017, accounts receivable was comprised of the following:

(in thousands)	September 30, 2018	December 31, 2017
Oil and gas sales	$ 53,501	$ 42,869
Joint interest	21,401	7,860
Other	3,368	5
Total accounts receivable	$ 78,270	$ 50,734

At September 30, 2018 and December 31, 2017, the Company did not have any reserves for doubtful accounts and did not incur any bad debt expense in any period presented.

Oil and Natural Gas Properties

A summary of the Company's oil and natural gas properties, net is as follows:

(in thousands)	September 30, 2018	December 31, 2017
Proved oil and natural gas properties	$ 1,586,098	$ 1,012,321
Unproved oil and natural gas properties	174,592	183,510
Total oil and natural gas properties	1,760,690	1,195,831
Less: Accumulated depletion	(325,567)	(166,592)
Total oil and natural gas properties, net	$ 1,435,123	$ 1,029,239

Capitalized leasehold costs attributable to proved properties are depleted using the units-of-production method based on proved reserves on a field basis. Capitalized well costs, including asset retirement costs, are depleted based on proved developed reserves on a field basis. For the three months ended September 30, 2018 and 2017, the Company recorded depletion for oil and natural gas properties of $57.2 million and $30.4 million, respectively. For the nine months ended September 30, 2018 and 2017, the Company recorded depletion for oil and natural gas properties of $159.0 million and $65.9 million, respectively. Depletion expense is included in depletion, depreciation, amortization and accretion expense on the accompanying consolidated and combined statements of operations.

Accrued Liabilities

The components of accrued liabilities are shown below:

(in thousands)	September 30, 2018	December 31, 2017
Accrued capital expenditures	$ 87,429	$ 102,956
Accrued accounts payable	10,102	8,488
Royalties payable	22,536	6,105
Other current liabilities	34,473	14,762
Total accrued liabilities	$ 154,540	$ 132,311

Recent Accounting Pronouncements

Recently Adopted Accounting Standards

Revenue from Contracts with Customers. In May 2014, the Financial Accounting Standards Board ("FASB") issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, which outlined a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most prior revenue recognition guidance, including industry-specific guidance. The Company adopted the new standard on January 1, 2018, as described above. The Company implemented the necessary changes to its business processes, systems and controls to support recognition and disclosure of this new standard.

The Company's financial statement presentation related to revenue received from certain gas sales contracts changed as a result of the new standard. Under previous guidance, proceeds from certain gas sales contracts were reported gross, with related costs for gathering and processing being presented separately as gathering and processing expense. Upon adoption of the new standard, the Company presents revenue from these contracts net of gathering and processing costs, as these costs are incurred after control of the product is transferred to the customer. The impact of the new revenue recognition standard on the Company's current period results is as follows:

	Three Months Ended September 30, 2018		
(in thousands)	Amounts presented on statements of operations	ASC 606 Adjustments	Previous Revenue Recognition Method
Revenues			
Oil sales	$ 141,598	$ —	$ 141,598
Natural gas sales	2,552	1,102	3,654
NGL sales	10,814	3,604	14,418
Other operating revenues	414	—	414
Total revenues	$ 155,378	$ 4,706	$ 160,084
Operating expenses			
Gathering and processing expenses	$ —	$ 4,706	$ 4,706
Net income (loss)	$ (26,566)	$ —	$ (26,566)

	Nine Months Ended September 30, 2018		
(in thousands)	Amounts presented on statements of operations	ASC 606 Adjustments	Previous Revenue Recognition Method
Revenues			
Oil sales	$ 410,935	$ —	$ 410,935
Natural gas sales	7,765	2,987	10,752
NGL sales	23,721	8,205	31,926
Other operating revenues	686	—	686
Total revenues	$ 443,107	$ 11,192	$ 454,299
Operating expenses			
Gathering and processing expenses	$ —	$ 11,192	$ 11,192
Net income (loss)	$ (20,888)	$ —	$ (20,888)

Adoption of the new standard did not impact the Company’s previously reported results of operations or consolidated and combined cash flows statements.

Stock Compensation - Scope of Modification Accounting. In May 2017, the FASB issued ASU 2017-09, *Compensation-Stock Compensation (Topic 718) Scope of Modification Accounting*. The ASU clarified which changes to the terms or conditions of an equity-based payment award require an entity to apply modification accounting in Topic 718. The standard became effective for the Company on January 1, 2018. The adoption of this new standard did not impact the Company’s consolidated and combined balance sheets, statements of operations or statements of cash flows.

Accounting Standards Not Yet Adopted

Leases. In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, which requires entities to determine at the inception of a contract if the contract is, or contains, a lease. Entities are then required to recognize leases as right-of-use assets and lease payment liabilities on the balance sheet as well as disclose key information about leasing arrangements. The new standard is effective for the Company on January 1, 2019. Entities are permitted to make a policy election under ASU 2016-02 to not recognize lease assets or liabilities when the term of the lease is less than twelve months. For agreements that contain both lease and non-lease components, entities are also permitted to make a policy election to combine both the lease and non-lease components together and account for these arrangements as a single lease. The update does not apply to leases of mineral rights to explore for or use oil and natural gas. ASU 2016-02 retains a distinction between finance and operating leases concerning the recognition and presentation of the expense and payments related to leases in the statements of operations and cash flows. Under ASU 2016-02, entities are required to adopt the new standard using a modified retrospective approach and apply the provisions of ASU 2016-02 to leasing arrangements existing at, or entered into, after the earliest comparative period presented in the financial statements. In January 2018, the FASB issued ASU 2018-01, *Land Easement Practical Expedient for Transition to Topic 842*, which permits an entity to elect an optional transition practical expedient to not evaluate land easements that exist or expire before the Company's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840. In July 2018, the FASB issued ASU 2018-11, *Targeted Improvements*, which provides entities an optional transitional relief method whereby prior periods would not require restatement while a cumulative adjustment to retained earnings during the period of adoption would be recorded.

The Company continues to evaluate the impact of ASU 2016-02, as amended, which includes an analysis of existing contracts, including drilling rig and frac fleet contracts, field equipment contracts, office leases and other existing arrangements that may contain a lease component. The Company is also evaluating the impact of ASU 2016-02, as amended, on its current accounting policies, processes and controls as it relates to the new accounting and disclosure requirements. The Company is also in the process of implementing a lease administration system that will support the on-going maintenance and accounting for leases after the adoption of ASU 2016-02. The Company intends to adopt ASU 2016-02 and ASU 2018-01 using the optional transitional relief method provided for in ASU 2018-11. The Company believes that adopting ASU 2016-02 will result in increases to the assets and liabilities on its consolidated and combined balance sheets and additional disclosures of key information related to its leases.

Note 3—Derivative Instruments

The Company hedges a portion of its crude oil sales through derivative instruments to mitigate volatility in commodity prices. The use of these instruments exposes the Company to market basis differential risk if the WTI price does not move in parity with the Company's underlying sales of crude oil produced in the southern Delaware Basin. The Company also hedges a portion of its market basis differential risk through basis swap contracts.

The Company's derivative instruments are carried at fair value on the consolidated and combined balance sheets. The Company estimates the fair value using risk adjusted discounted cash flow calculations. Cash flows are based on published future commodity price curves for the underlying commodity as of the date of the estimate. Due to the volatility of commodity prices, the estimated fair values of the Company's derivative instruments are subject to fluctuation from period to period, which could result in significant differences between the current estimated fair value and the ultimate settlement price. For more information, refer to Note 9, *Fair Value Measurements*.

In an effort to reduce the variability of the Company's cash flows, the Company hedged the commodity prices associated with a portion of its expected future oil volumes by entering into swap and basis swap derivative financial instruments. With swaps, the Company typically receives an agreed upon fixed price for a specified notional quantity of oil or natural gas, and the Company pays the hedge counterparty a floating price for that same quantity based upon published index prices. Basis swap contracts establish the differential between Cushing WTI prices and Midland WTI prices for the notional volumes contracted. The Company's commodity derivatives may expose it to the risk of financial loss in certain circumstances. The Company's derivative arrangements provide protection on the hedged volumes if market prices decline below the prices at which these derivatives are set. If market prices rise above the prices at which the Company has hedged, the Company will be required to make settlement payments to its derivative counterparties.

The following table summarizes the Company's derivative contracts as of September 30, 2018:

Contract Period	Volumes (Bbls)	Wtd Avg Price ($/Bbl)
Oil Swaps: (1)		
Fourth quarter 2018	1,789,400	$ 55.66
Year ending December 31, 2019	7,665,000	$ 59.95
Year ending December 31, 2020	2,928,000	$ 60.82
Oil Basis Swaps: (2)		
Fourth quarter 2018	1,610,000	$ (2.27)
Year ending December 31, 2019	8,763,000	$ (5.92)
Year ending December 31, 2020	9,516,000	$ (1.31)

(1) The index prices for the oil swaps are based on the NYMEX–WTI monthly average futures price.
(2) The oil basis swap differential price is between Cushing–WTI and Midland–WTI.

The Company has elected to not apply hedge accounting, and as a result, its earnings are affected by the use of the mark-to-market method of accounting for derivative financial instruments. Accordingly, the changes in fair value of these instruments are recognized through current earnings as other income or expense as they occur. The use of mark-to-market accounting for financial instruments can cause noncash earnings volatility due to changes in the underlying commodity price indices. The ultimate gain or loss upon settlement of these transactions is recognized in earnings as other income or expense. Cash settlements of the Company's derivative contracts are included in cash flows from operating activities in the Company's statements of cash flows.

JAGGED PEAK ENERGY INC.

Notes to Consolidated and Combined Financial Statements
(Unaudited)

The Company recognized the following gains (losses) and net cash receipts (payments) in earnings for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Gain (loss) on derivative instruments, net	$ (96,516)	$ (27,693)	$ (110,426)	$ 15,922
Net cash receipts (payments) on settled derivatives	$ (6,347)	$ 3,195	$ (33,705)	$ 3,691

The Company's derivative contracts are carried at their fair value on the Company's consolidated and combined balance sheets using Level 2 inputs, and are subject to industry standard master netting arrangements, which allow the Company to offset recognized asset and liability fair value amounts on contracts with the same counterparty. The Company's policy is to not offset these positions in its consolidated and combined balance sheets.

The following tables present the amounts and classifications of the Company's commodity contract derivative assets and liabilities as of September 30, 2018 and December 31, 2017 (in thousands):

As of September 30, 2018:	**Balance Sheet Location**	**Gross amounts presented on the balance sheet**	**Netting adjustments not offset on the balance sheet**	**Net amounts**
Assets				
Commodity contracts	Current assets - derivative instruments	$ 19,991	$ (19,991)	$ —
Commodity contracts	Noncurrent assets - derivative instruments	719	(719)	—
Total assets		$ 20,710	$ (20,710)	$ —
Liabilities				
Commodity contracts	Current liabilities - derivative instruments	$ 104,490	$ (19,991)	$ 84,499
Commodity contracts	Noncurrent liabilities - derivative instruments	45,792	(719)	45,073
Total liabilities		$ 150,282	$ (20,710)	$ 129,572

As of December 31, 2017:	**Balance Sheet Location**	**Gross amounts presented on the balance sheet**	**Netting adjustments not offset on the balance sheet**	**Net amounts**
Assets				
Commodity contracts	Current assets - derivative instruments	$ —	$ —	$ —
Commodity contracts	Noncurrent assets - derivative instruments	26	(26)	—
Total assets		$ 26	$ (26)	$ —
Liabilities				
Commodity contracts	Current liabilities - derivative instruments	$ 41,782	$ —	$ 41,782
Commodity contracts	Noncurrent liabilities - derivative instruments	11,095	(26)	11,069
Total liabilities		$ 52,877	$ (26)	$ 52,851

Derivative Counterparty Risk

Where the Company is exposed to credit risk in its financial instrument transactions, management analyzes the counterparty's financial condition prior to entering into an agreement and monitors the appropriateness of these counterparties on an ongoing basis. Generally, the Company does not require collateral and does not anticipate nonperformance by its counterparties.

The Company's counterparty credit exposure related to commodity derivative instruments comprises contracts with a net positive fair value at the reporting date. These outstanding instruments, if any, expose the Company to credit risk in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of the Company's counterparties decline, its ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third-party. In the event of a counterparty default, the Company may sustain a loss and its cash receipts could be negatively impacted.

At September 30, 2018, the Company had commodity derivative contracts with six counterparties, all of which were lenders under the Company's Amended and Restated Credit Facility (as defined in Note 4, *Debt*) and all of which had investment grade credit ratings. These counterparties accounted for all the Company's counterparty credit exposure related to commodity derivative assets.

Note 4—Debt

The Company's debt consisted of the following at September 30, 2018 and December 31, 2017:

(in thousands)	September 30, 2018	December 31, 2017
Senior secured revolving credit facility	$ —	$ 155,000
5.875% senior unsecured notes due 2026	500,000	—
Debt issuance costs on senior unsecured notes	(11,028)	—
Total long-term debt	$ 488,972	$ 155,000

Senior Secured Revolving Credit Facility

At December 31, 2017, the Company's amended and restated credit facility, as amended (the "Amended and Restated Credit Facility"), had a borrowing base of $425.0 million, with $155.0 million outstanding. In March 2018, the Company entered into Amendment No. 2 to the Amended and Restated Credit Facility, which extended the maturity date of the Amended and Restated Credit Facility to March 21, 2023 and increased the borrowing base to $540.0 million. Borrowings under the Amended and Restated Credit Facility under Amendment No. 2 bear interest at a rate elected by the Company that is equal to an adjusted base rate (which is equal to the greatest of the prime rate, the federal funds effective rate plus 0.50% and the thirty-day adjusted LIBOR plus 1.0%) or LIBOR, in each case, plus the applicable margin. The applicable margin ranges from 0.50% to 1.50% in the case of the adjusted base rate, and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the elected commitments. The Company also incurs a commitment fee that is between 0.375% to 0.50% per year on the unused portion of the elected commitments, depending on the relative amount of the loan outstanding in relation to the elected commitments.

In April 2018, and in connection with the issuance of the Senior Notes (as described and defined below), the lenders of the Amended and Restated Credit Facility agreed to waive a provision that would require a borrowing base reduction as a result of the Senior Notes. As a result, the borrowing base of the Amended and Restated Credit Facility continued to be $540.0 million. The Company also voluntarily elected to reduce the elected commitments to $475.0 million, effective as of the closing of the Senior Notes offering. Additionally, a portion of the proceeds from the Senior Notes were used to repay the entire outstanding balance under the Amended and Restated Credit Facility of $320.0 million as of the date the Senior Notes proceeds were received.

In June 2018, the Company entered into Amendment No. 3 to the Amended and Restated Credit Facility which increased the amount the Company is permitted to hedge up to 85% of forecasted future production for up to 36 months in the future, and up to the greater of 75% of its proved reserves and 60% of its reasonably anticipated forecasted production for 37 to 60 months in the future, provided that no hedges have a term beyond five years.

In August 2018, the Company entered into Amendment No. 4 to the Amended and Restated Credit Facility which increased the borrowing base to $825.0 million and the Company increased its elected commitments to $540.0 million. In November 2018, the borrowing base of the Amended and Restated Credit Facility increased to $900.0 million while the elected commitments remained at $540.0 million.

The Amended and Restated Credit Facility contains certain nonfinancial covenants, including among others, restrictions on indebtedness, liens, investments, mergers, sales of assets, hedging activity, and dividends and payments to the Company's capital interest holders.

The Amended and Restated Credit Facility also contains financial covenants, which are measured on a quarterly basis. The covenants, as defined in the Amended and Restated Credit Facility, include requirements to comply with the following financial ratios:

Financial Covenant	Required Ratio			
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than	1.0	to	1.0
Ratio of debt to EBITDAX, as defined in the credit agreement	Not greater than	4.0	to	1.0

As of September 30, 2018, the Company was in compliance with its Amended and Restated Credit Facility financial covenants.

5.875% Senior Unsecured Notes due 2026

On May 8, 2018, JPE LLC issued $500.0 million aggregate principal amount of 5.875% senior unsecured notes that mature on May 1, 2026 (the “Senior Notes”) in a 144A private placement that was exempt from registration under the Securities Act. Interest is payable on the Senior Notes semi-annually in arrears on each May 1 and November 1, commencing November 1, 2018. The Senior Notes resulted in net proceeds to the Company of $488.4 million, after deducting the initial purchasers’ discount and offering expenses. A portion of such proceeds was used to repay the entire outstanding balance under the Amended and Restated Credit Facility of $320.0 million as of the date the Senior Notes proceeds were received. The remainder of the net proceeds are expected to be used to fund a portion of the Company’s 2018 capital program and for other general corporate purposes.

The Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by Jagged Peak and may be guaranteed by future subsidiaries. Jagged Peak has no independent assets or operations and has no other subsidiaries other than JPE LLC. There are no significant restrictions on the Company’s ability to obtain funds from its subsidiary in the form of cash dividends or other distributions of funds.

In connection with the issuance of the Senior Notes, the Company entered into a registration rights agreement with the initial purchasers, dated May 8, 2018, to allow holders of the unregistered Senior Notes to exchange the unregistered Senior Notes for registered notes that have substantially identical terms. The Company agreed to use reasonable efforts to cause the exchange to be completed within 360 days after the issuance of the Senior Notes. The Company is required to pay additional interest if it fails to comply with its obligations to complete the exchange offer of the Senior Notes within the specified time period, whereby the interest rate would be increased by up to 1.0% per annum during the period in which a registration default is in effect. The Company expects to comply with the terms of the registration rights agreement and complete the exchange of the Senior Notes within the 360-day period.

If the Company experiences certain defined changes of control, each holder of the Senior Notes may require the Company to repurchase all or a portion of its Senior Notes for cash at a price equal to 101% of the aggregate principal amount of such Senior Notes plus accrued and unpaid interest as of the date of repurchase, if any.

The indenture governing the Senior Notes contains covenants that, among other things and subject to certain exceptions and qualifications, limit the Company’s ability and the ability of the Company’s restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries.

Note 5—Equity-based Compensation

Equity-based compensation expense, for each type of equity-based award, was as follows for the periods indicated:

(in thousands)	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Incentive unit awards	$ 609	$ 10,692	$ 75,767	$ 429,585
Restricted stock unit awards	883	521	2,996	898
Performance stock unit awards	1,016	527	1,513	866
Restricted stock unit awards issued to nonemployee directors	106	163	395	293
Total equity-based compensation expense	$ 2,614	$ 11,903	$ 80,671	$ 431,642

Equity-based compensation expense, which is recorded in general and administrative expense in the accompanying consolidated and combined statements of operations, will fluctuate based on the grant-date fair value of awards, the number of awards, the requisite service period of the awards, modification of awards, employee forfeitures and the timing of the awards.

For the nine months ended September 30, 2018, equity-based compensation expense includes $71.3 million related to a modification of the service requirements in February 2018 for the incentive unit awards allocated at the IPO (as described further below). For the nine months ended September 30, 2017, equity-based compensation expense of $431.6 million included (1) $379.0 million related to the vested shares of common stock at the IPO date, all of which was noncash except for $14.7 million related to a management incentive advance payment made in April 2016, and (2) $22.2 million related to a modification in conjunction with a March 2017 separation agreement of a former executive officer.

In February 2018, certain employees notified the Company of their desire to terminate their employment. Under the terms of the JPE Management Holdings LLC limited liability company agreement ("Management Holdco LLC Agreement"), upon voluntary termination of employment by an incentive unit award holder, the Board of Directors has the discretion to allow outstanding unvested incentive unit awards to immediately vest, to continue to vest post-termination, and/or to be automatically forfeited, or any combination thereof. Any forfeited incentive units would be reallocated to the remaining incentive unit holders employed by the Company. In February 2018, the Board of Directors modified these employees' unvested incentive units to either immediately accelerate vesting, in the case of retiring employees, or continue to vest post-termination under the original vesting period. The Company determined that these changes should be accounted for as modifications under ASC 718 in the first quarter of 2018. As a result of these modifications to the service requirements, the Company determined that, for accounting purposes under ASC 718, the incentive unit awards allocated at IPO no longer met the substantive service condition, and that any previously unrecognized equity-based compensation expense should be recognized immediately. The acceleration of all previously unrecognized equity-based compensation expense for incentive unit awards allocated at the time of the IPO resulted in the recognition of $71.3 million of noncash equity-based compensation expense in the first quarter of 2018. This accounting does not alter the legal service obligations under the Management Holdco LLC Agreement for remaining employees whose awards were not modified. Equity-based compensation expense recognition related to incentive unit awards that were unallocated at the time of the IPO is unaffected.

The following table summarizes the Company's incentive unit award, restricted stock unit ("RSU") award and performance stock unit ("PSU") award activity for the nine months ended September 30, 2018:

	Incentive Units (2)	RSUs (3)	PSUs
Unvested at December 31, 2017	7,755,745	582,973	398,566
Awards Granted (1)	423,642	608,771	546,319
Vested	(2,789,511)	(265,779)	—
Forfeited	(73,307)	(138,548)	(253,522)
Unvested at September 30, 2018	5,316,569	787,417	691,363

(1) Weighted average grant-date fair value was $13.37 for incentive units, $12.72 for RSUs and $16.23 for PSUs.
(2) Included in the unvested incentive units at September 30, 2018 are 4,809,666 units for which equity-based compensation expense was accelerated and fully recognized in February 2018. See the discussion above for additional information.

(3) Of the 608,771 RSUs granted during 2018, nonemployee directors received 30,753 at a weighted average grant-date fair value of $13.17.

The following table reflects the future equity-based compensation expense to be recorded for each type of award that was outstanding at September 30, 2018:

	Incentive Units	RSUs (1)	PSUs
Compensation costs remaining at September 30, 2018 (in millions)	$ 5.4	$ 7.9	$ 8.2
Weighted average remaining period at September 30, 2018 (in years)	2.4	2.2	2.1

(1) The remaining compensation costs at September 30, 2018 for the nonemployee director RSUs was $0.3 million, with a weighted average remaining period of 0.6 years.

At September 30, 2018, there were 80,986 unallocated incentive units that are available to be granted. When these units are granted, they will be valued using the closing stock price on the date of grant, and the Company will recognize the related expense over the requisite service period.

Note 6—Earnings Per Share

Basic earnings per share ("EPS") is computed by dividing net earnings by the weighted average number of shares of common stock outstanding for the period. Diluted earnings per share is similarly computed, except that the denominator includes the effect, using the treasury stock method, of unvested RSUs and PSUs if including such potential shares of common stock units is dilutive. The PSUs included in the calculation of diluted weighted average shares outstanding are based on the number of shares of common stock that would be issuable if the end of the reporting period was the end of the performance period required for the vesting of such PSU awards. During periods in which the Company incurs a net loss, diluted weighted average shares outstanding are equal to basic weighted average shares outstanding because the effect of all awards is anti-dilutive.

For the nine months ended September 30, 2017, the Company's EPS calculation includes only the net loss for the period subsequent to the corporate reorganization and IPO and omits income or loss prior to these events. In addition, the basic weighted average shares outstanding calculation is based on the actual days in which the shares were outstanding for the period from January 27, 2017 to September 30, 2017.

A reconciliation of the components of basic and diluted earnings per common share is presented in the table below:

	Three Months Ended September 30,		Nine Months Ended	From January 27, 2017, to
(in thousands, except per share amounts)	2018	2017	September 30, 2018	September 30, 2017
Net income (loss) attributable to Jagged Peak Energy Inc. stockholders	$ (26,566)	$ (15,219)	$ (20,888)	$ (89,221)
Basic weighted average shares outstanding	213,180	212,931	213,109	212,933
Dilutive restricted stock units	—	—	—	—
Dilutive performance stock units	—	—	—	—
Diluted weighted average shares outstanding	213,180	212,931	213,109	212,933
Net income (loss) per common share:				
Basic	$ (0.12)	$ (0.07)	$ (0.10)	$ (0.42)
Diluted	$ (0.12)	$ (0.07)	$ (0.10)	$ (0.42)

The following table presents the weighted average number of outstanding equity awards that have been excluded from the computation of diluted earnings per common share as their inclusion would be anti-dilutive:

(in thousands)	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	From January 27, 2017, to September 30, 2017
Number of antidilutive units: (1)				
Antidilutive restricted stock units	791	527	721	348
Antidilutive performance stock units	603	671	496	421

(1) When the Company incurs a net loss, all outstanding equity awards are excluded from the calculation of diluted loss per common share because the inclusion of these awards would be anti-dilutive.

Note 7—Income Taxes

Income tax expense was as follows for the periods indicated:

(in thousands)	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Income tax expense (benefit)	$ (7,315)	$ (2,598)	$ 14,737	$ 101,039
Effective tax rate	21.6%	14.6%	(239.6)%	(27.8)%

JPE LLC was organized as a limited liability company and treated as a pass-through entity for federal income tax purposes. As such, taxable income and any related tax credits were passed through to its members and included in their tax returns. Accordingly, provision for federal and state corporate income taxes has been made only for the operations of the Company from January 27, 2017 in the accompanying consolidated and combined financial statements. Included in the deferred federal income tax provision above for the nine months ended September 30, 2017, is a $79.1 million income tax expense related to the Company's change in tax status as a result of the corporate reorganization.

The Company computes its quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to its year-to-date income, except for discrete items. Income taxes for discrete items are computed and recorded in the period that the specific transaction occurs. For the three months ended September 30, 2018, the Company's overall effective tax rate was different than the federal statutory rate of 21% primarily due to permanent differences on vested equity-based compensation awards. For the nine months ended September 30, 2018, the Company's overall effective tax rate was different than the federal statutory rate of 21% primarily due to nondeductible equity-based compensation related to incentive unit awards allocated at the time of the IPO, and permanent differences on vested equity-based compensation awards. For the three and nine months ended September 30, 2017, the Company's overall effective tax rate was different than the federal statutory rate of 35% primarily due to the impact of the change in tax status and nondeductible equity-based compensation.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"). Due to the complexities involved in accounting for the enactment of the new law, the Securities and Exchange Commission ("SEC") issued Staff Accounting Bulletin ("SAB") 118 that allowed for a measurement period of up to one year after the enactment date of the Tax Act to finalize the impact of the Tax Act on a company's financial statements. The Company substantially completed its analysis of the Tax Act and recorded its estimated impact in the year ended December 31, 2017. As of September 30, 2018, the Company has not made any material adjustments to its provisional estimate at December 31, 2017. Any changes to the calculation that do arise will be recorded as they are identified during the measurement period provided for by SAB 118.

Note 8—Asset Retirement Obligations

The following table summarizes the changes in the carrying amount of the asset retirement obligations for the nine months ended September 30, 2018. The current portion of the asset retirement obligation liability is included in accrued liabilities on the consolidated and combined balance sheets.

(in thousands)	
Asset retirement obligations at January 1, 2018	$ 929
Liabilities incurred and assumed	533
Liability settlements and disposals	(33)
Revisions of estimated liabilities	35
Accretion	88
Asset retirement obligations at September 30, 2018	1,552
Less current portion of asset retirement obligations	(125)
Long-term asset retirement obligations	$ 1,427

Note 9—Fair Value Measurements

Fair value is 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 (exit price). Financial assets and liabilities are measured at fair value on a recurring basis. Nonfinancial assets and liabilities, such as the initial measurement of asset retirement obligations and oil and natural gas properties upon acquisition or impairment, are recognized at fair value on a nonrecurring basis.

The Company categorizes the inputs to the fair value of its financial assets and liabilities using a three-tier fair value hierarchy, established by the FASB, that prioritizes the significant inputs used in measuring fair value:

Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed securities and U.S. government treasury securities.

Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry standard models that consider various assumptions, including quoted prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in the category include nonexchange-traded derivatives such as over-the-counter forwards, swaps and options.

Level 3—Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value, and the company does not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Reclassifications of fair value among Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. There were no transfers among Level 1, Level 2 or Level 3 during the nine months ended September 30, 2018.

Assets and liabilities measured on a recurring basis

Certain assets and liabilities are reported at fair value on a recurring basis. The following table sets forth the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis:

	Level 2	
(in thousands)	**September 30, 2018**	**December 31, 2017**
Assets from commodity derivative contracts	$ 20,710	$ 26
Liabilities due to commodity derivative contracts	$ 150,282	$ 52,877

The fair value of the Company's oil swaps and basis swaps is computed using discounted cash flows for the duration of each commodity derivative instrument using the terms of the related contract. Inputs consist of published forward commodity price curves as of the date of the estimate. The Company compares these prices to the price parameters contained in its hedge contracts to determine estimated future cash inflows or outflows, which are then discounted. The fair values of the Company's commodity derivative assets and liabilities include a measure of credit risk. These valuations are Level 2 inputs.

Fair Value of Other Financial Instruments

The following table provides the fair value of financial instruments that are not recorded at fair value in the consolidated and combined balance sheets:

	September 30, 2018		December 31, 2017	
(in thousands)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt:				
Senior secured revolving credit facility	$ —	$ —	$ 155,000	$ 155,000
5.875% senior unsecured notes due 2026	$ 500,000	$ 497,715	$ —	$ —

The fair value of the Amended and Restated Credit Facility approximates its carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy. The fair value of the Senior Notes at September 30, 2018 was based on the quoted market price and is classified as Level 1 in the fair value hierarchy.

The carrying value of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities are considered to be representative of their respective fair values due to the nature of and short-term maturities of those instruments.

Assets and liabilities measured on a nonrecurring basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments in certain circumstances. These assets and liabilities include the acquisition or impairment of proved and unproved oil and gas properties and the inception value of asset retirement obligation liabilities.

Proved oil and natural gas properties. The Company reviews its proved oil and natural gas properties for impairment whenever facts and circumstances indicate their carrying value may not be recoverable. In such circumstances, the income approach is used to determine the fair value of proved oil and natural gas reserves. Under this approach, the Company estimates the expected future cash flows of oil and natural gas properties and compares these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will write down the carrying amount of the oil and natural gas properties to estimated fair value. The factors used to determine fair value may include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures and a commensurate discount rate. These assumptions and estimates represent Level 3 inputs.

Unproved oil and nature gas properties. Unproved oil and natural gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. To measure the fair value of the unproved properties, the Company uses a market approach, and takes into account future development plans, remaining lease term, drilling results and reservoir performance. These assumptions and estimates represent Level 3 inputs.

The following table sets forth the noncash impairments of both proved and unproved properties for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2018	2017	2018	2017
Proved oil and natural gas property impairments	$ —	$ —	$ —	$ —
Unproved oil and natural gas property impairments (1)	—	257	53	365
	$ —	$ 257	$ 53	$ 365

(1) The impairments of unproved oil and natural gas properties resulted from expirations of certain undeveloped leases.

Asset retirement obligations. The inception value and new layers resulting from upward revisions of the Company's asset retirement obligations are also measured at fair value on a nonrecurring basis. The inputs used to determine such fair value are based primarily on the present value of estimated future cash outflows. Given the unobservable nature of these inputs, they represent Level 3 inputs.

Note 10—Commitments and Contingencies

Commitments

There were no material changes in commitments during the first nine months of 2018, except as discussed below. Please refer to Note 10, *Commitments and Contingencies*, in the 2017 Form 10-K for additional discussion.

At September 30, 2018, the Company had four operated drilling rigs running, two of which were released in October 2018 with no penalties incurred. As of September 30, 2018, the Company had signed four new rig contracts that are expected to begin running during the fourth quarter of 2018. With the addition of the new rigs, the Company's total commitment for drilling rigs at September 30, 2018 is $81.8 million through 2020. If the Company were to terminate its drilling rig contracts at September 30, 2018, including all rigs running and contracted, it would be required to pay early termination penalties of $44.1 million.

Contingencies

Legal Matters

In the ordinary course of business, the Company may at times be subject to claims and legal actions. Management believes it is remote that the impact of any such current matters will have a material adverse effect on the Company's financial position, results of operations or cash flows.

Environmental Matters

The Company accounts for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed.

Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At both September 30, 2018 and December 31, 2017, the Company had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Note 11—Related Party Transactions

As a result of Quantum's significant ownership interest in the Company, the Company identified Oryx Midstream Services, LLC (together with Oryx Southern Delaware Holdings, LLC, "Oryx"), Phoenix Lease Services, LLC ("Phoenix") and

Trident Water Services, LLC ("Trident"), a wholly owned subsidiary of Phoenix, as related parties. These entities are considered related parties as Quantum owns an interest, either directly or indirectly, in each entity.

The following table summarizes fees paid to Oryx, Phoenix and Trident for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2018	2017	2018	2017
Oryx via 3rd party shipper (1)	$ 6,435	$ 2,918	$ 16,719	$ 6,716
Oryx (2)	$ 140	$ 97	$ 440	$ 749
Phoenix (3)	$ 98	$ 56	$ 319	$ 258
Trident (3)	$ —	$ —	$ —	$ 236

(1) Fees paid by the Company's third-party shipper to Oryx pursuant to the crude oil transportation and gathering agreement are netted against revenue as they are included in the net price paid by to the third-party shipper.
(2) Fees paid to Oryx for the purchase and installation of metering equipment are capitalized to proved properties on the consolidated and combined balance sheets.
(3) Fees paid to Phoenix and Trident are capitalized to proved properties on the consolidated and combined balance sheets.

At September 30, 2018 and December 31, 2017, the Company had outstanding payables to these related parties of $2.4 million and $1.8 million, respectively. See Note 11, *Related Party Transactions*, in the 2017 Form 10-K for more information.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our consolidated and combined financial statements and related notes presented in this Quarterly Report on Form 10-Q as well as our audited consolidated and combined financial statements and related notes included in our Annual Report on Form 10-K for the year ended December 31, 2017. The following discussion and analysis contains forward-looking statements, including, without limitation, statements related to our future plans, estimates, beliefs and expected performance. Please see "Cautionary Statement Concerning Forward-Looking Statements" in this Quarterly Report on Form 10-Q, "Item 8.01, Other Events" in our Current Report on Form 8-K filed with the Securities and Exchange Commission on April 23, 2018 and "Part 1, Item 1A. Risk Factors" in our 2017 Form 10-K.

In this section, references to "Jagged Peak," "the Company," "we," "us" and "our" refer to Jagged Peak Energy Inc. and its subsidiaries, after the IPO and, prior to the IPO, to Jagged Peak Energy LLC ("JPE LLC").

Jagged Peak Energy Inc. and our Predecessor

Jagged Peak was formed in September 2016 and, prior to the consummation of the IPO, did not have historical financial operating results. JPE LLC, our accounting predecessor, was formed in 2013 to engage in the acquisition, development, exploration and exploitation of oil and natural gas reserves. In connection with the IPO, a corporate reorganization took place whereby JPE LLC became a wholly owned subsidiary of Jagged Peak.

Overview

We are an independent oil and natural gas company focused on the acquisition and development of unconventional oil and associated liquids-rich natural gas reserves. Our operations are entirely located in the United States, within the Permian Basin of West Texas. Our primary area of focus is the southern Delaware Basin; the Delaware Basin is a sub-basin of the Permian Basin. Our acreage is located on large, contiguous blocks in the adjacent Texas counties of Winkler, Ward, Reeves and Pecos, with significant original oil-in-place within multiple stacked hydrocarbon-bearing formations.

We have assembled a portfolio of contiguous acreage in the core oil window of the southern Delaware Basin. This acreage is characterized by a multi-year, oil-weighted inventory of horizontal drilling locations that provide attractive growth and return opportunities. At September 30, 2018, our acreage position was approximately 78,900 net acres.

Our revenue, profitability and future growth are highly dependent on the prices we receive for our oil, natural gas and NGL production. Compared to the first nine months of 2017, our realized oil price for the first nine months of 2018 increased 28% to $59.15 per barrel, our realized natural gas price declined 50% to $1.29 per Mcf, and our realized price for NGLs increased by 6% to $23.71 per barrel between these same periods. The realized natural gas and NGL prices during the first nine months of 2018 were negatively impacted by the adoption of ASC 606, which requires us to deduct gathering and processing costs from revenue rather than record it as a separate expense. See below for further information regarding the "Adoption of ASC 606" related to the impact of the new revenue recognition standard on our natural gas and NGL revenues and corresponding realized prices, and "Sources of Our Revenues" regarding our realized commodity prices.

Factors Affecting the Comparability of Our Results of Operations

Our historical results of operations for the periods presented may not be comparable, either to each other or to our future results of operations, primarily for the reasons described below.

Increased Oil and Natural Gas Development Activities

During the nine months ended September 30, 2018, we brought online, or participated in bringing online, 49 gross (38.6 net) wells. Our average daily production grew 125% from 14,594 Boe/d during the first nine months of 2017 to 32,790 Boe/d for the same period of 2018. In the nine months ended September 30, 2018, we spent $550.1 million on drilling and completing wells and on further developing our water infrastructure. This compares to $420.9 million that we spent in the nine months ended September 30, 2017 for drilling, completion and infrastructure.

Equity-based Compensation

During the nine months ended September 30, 2018, we recognized equity-based compensation expense of $80.7 million, which included $71.3 million related to a modification of service requirements for incentive unit awards. During the nine months ended September 30, 2017, we recognized equity-based compensation of $431.6 million which included $379.0 million related to incentive unit awards that vested at the time of the IPO. Please refer to Note 5, *Equity-based Compensation*, in "Part I. Financial Information - Item 1. Financial Statements" for additional information on equity-based compensation.

Income Taxes

As a result of our corporate reorganization, we became subject to federal and state income tax. The change in tax status required the recognition of deferred tax assets and liabilities for the temporary differences at the time of the change in status. The resulting net deferred tax liability of approximately $79.1 million was recognized as tax expense from continuing operations during the nine months ended September 30, 2017. For periods following completion of the corporate reorganization, we began recording income taxes associated with our status as a corporation. Please refer to Note 7, *Income Taxes*, in "Part I. Financial Information - Item 1. Financial Statements" for more information on income taxes.

The Tax Act, which was signed into law in December 2017, significantly changed the federal income taxation of business entities. The Tax Act, among other things, reduces the corporate income tax rate from 35% to 21%, partially limits the deductibility of business interest expense and net operating losses, allows the immediate deduction of certain new investments instead of deductions for depreciation expense over time and eliminates the corporate alternative minimum tax.

Adoption of ASC 606

As of January 1, 2018, we adopted ASC 606 using the modified retrospective method. This adoption did not have an impact on the opening balance of retained earnings. As a result of the adoption, we changed the presentation of the costs to gather and process natural gas and NGLs. For the nine months ended September 30, 2018, the adoption of ASC 606 resulted in a decrease of $11.2 million to our natural gas and NGL sales revenues, with a corresponding decrease to gathering and processing expense, but did not affect operating income, net income or operating cash flows. Comparative information for the prior period continues to be reported under the accounting standards in effect for that period. Adoption of the new standard did not impact natural gas or NGL production volumes. For additional information regarding the new revenue recognition standard, see Note 2, *Significant Accounting Policies and Related Matters*, in "Part I. Financial Information - Item 1. Financial Statements."

Summary of Operating and Financial Results

In the nine months ended September 30, 2018, as compared to the nine months ended September 30, 2017, we:

- Brought online 49 gross (38.6 net) wells, of which we operate 36 gross (33.5 net), all within the southern Delaware Basin;
- Increased average daily production by 125% to 32,790 Boe/d, comprised of 78% oil;
- Grew oil production 117% to 25,447 barrels per day, natural gas production by 171% to 22.1 MMcf/d and NGL production by 147% to 3,665 barrels per day;
- Increased production revenues by 172% to $442.4 million;
- Improved cash flow from operating activities to $317.7 million from $105.4 million;
- Recorded a $110.4 million loss on commodity derivative instruments compared to a $15.9 million gain;
- Incurred equity-based compensation expense of $80.7 million compared to $431.6 million;
- Successfully completed the offering of $500.0 million aggregate principal amount of 5.875% Senior Notes; and
- Repaid our outstanding borrowings on our Amended and Restated Credit Facility with a portion of the proceeds from the issuance of the 5.875% Senior Notes.

Sources of Our Revenues

Our revenues are derived from the sale of our oil and natural gas production, including the sale of NGLs that are extracted from our natural gas during processing. For the nine months ended September 30, 2018, our production revenues were derived 93% from oil sales, 2% from natural gas sales and 5% from NGL sales. Our oil, natural gas and NGL revenues do not include the effects of derivatives.

Increases or decreases in our revenue, profitability and future production are highly dependent on the commodity prices we receive. Oil, natural gas and NGL prices are market driven and have been historically volatile, and we expect that future prices will continue to fluctuate due to supply and demand factors, seasonality and geopolitical and economic factors.

The following table presents our average realized commodity prices, the effects of derivative settlements on our realized prices, and certain major U.S. index prices.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Crude Oil (per Bbl):				
Average NYMEX price	$ 69.69	$ 48.18	$ 66.93	$ 49.30
Average realized price	$ 55.95	$ 45.24	$ 59.15	$ 46.06
Average realized price, including derivative settlements	$ 53.45	$ 47.55	$ 54.30	$ 47.21
Natural Gas (per Mcf):				
Average NYMEX price	$ 2.93	$ 2.95	$ 2.95	$ 3.01
Average realized price (1)	$ 1.19	$ 2.59	$ 1.29	$ 2.56
NGLs (per Bbl):				
Average realized price (1)	$ 24.81	$ 25.31	$ 23.71	$ 22.28

(1) On January 1, 2018, we adopted ASC 606. As a result of adoption, natural gas and NGL realized prices for the three months ended September 30, 2018 include gathering and processing costs which reduced our realized natural gas and NGL prices by $0.52 per Mcf and $8.27 per barrel, respectively. For the nine months ended September 30, 2018, natural gas and NGL realized prices were reduced by $0.49 per Mcf and $8.20 per barrel, respectively. For additional information regarding the new revenue recognition standard, see Note 2, *Significant Accounting Policies and Related Matters,* in “Part I. Financial Information - Item 1. Financial Statements.”

While quoted NYMEX oil and natural gas prices are generally used as a basis for comparison within our industry, the prices we receive are affected by quality, energy content, location, gathering and processing and transportation differentials for these products.

See “Results of Operations” below for an analysis of the impact changes in realized prices had on our revenues.

In addition to sales of oil, natural gas and NGLs, we derive a minimal portion of our revenues from sales of fresh water and produced water disposal services to third parties. These revenues are reflected as other operating revenues on the consolidated and combined statements of operations.

Production Volumes Directly Impact Our Results of Operations

As reservoir pressures decline, production from a given well or formation decreases. Growth in our cash flow, future production and reserves will depend on our ability to continue to add production and proved reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through drilling, as well as acquisitions. Our ability to add reserves through successful drilling results and acquisitions is dependent on many factors, including our ability to increase our levels of cash flow from operations, borrow or raise capital, obtain regulatory approvals, procure materials, services and personnel and successfully identify and consummate acquisitions.

Derivative Activity

Historically, pricing for oil, natural gas and NGLs has been volatile and unpredictable, and we expect this volatility to continue in the future. As of September 30, 2018, we had entered into derivative oil swap contracts covering periods from October 1, 2018 through December 31, 2020 for approximately 12.4 MMbls of our projected oil production at a weighted average WTI oil price of $59.54 per barrel. We also have basis differential derivative contracts between Midland, TX and Cushing, OK for the periods from October 1, 2018 through December 31, 2020 covering 19.9 MMbls at a weighted average basis differential of $(3.42) per barrel. These derivative instruments allow us to reduce, but not eliminate, the potential variability in cash flow from operations due to fluctuations in oil prices. Our derivative instruments provide increased certainty of cash flows for funding our drilling program and debt service requirements. These instruments provide only partial price protection against declines in oil prices and may partially limit our potential gains from future increases in prices. During the three months ended September 30, 2018, we incurred net payments of $6.3 million related to derivative agreements that settled during this time. In the future, we may seek to hedge price risk associated with our natural gas and NGL production. See “Item 3—Quantitative and Qualitative Disclosure About Market Risk—Commodity Price Risk” for information regarding our exposure to market risk, including the effects of changes in commodity prices, and our commodity derivative contracts.

Results of Operations

Comparison of the three months ended September 30, 2018 versus September 30, 2017

Revenues

Oil and Natural Gas Revenues. The following table provides the components of our revenues for the three months ended September 30, 2018 and 2017, as well as each period's respective average realized prices and production volumes:

	Three Months Ended September 30,			
(in thousands or as indicated)	**2018**	**2017**	**Change**	**% Change**
Production revenues:				
Oil sales	$ 141,598	$ 62,585	$ 79,013	126 %
Natural gas sales	2,552	2,939	(387)	(13)%
NGL sales	10,814	4,860	5,954	123 %
Total production revenues	$ 154,964	$ 70,384	$ 84,580	120 %
Average realized price: (1) (2)				
Oil (per Bbl)	$ 55.95	$ 45.24	$ 10.71	24 %
Natural gas (per Mcf)	$ 1.19	$ 2.59	$ (1.40)	(54)%
NGLs (per Bbl)	$ 24.81	$ 25.31	$ (0.50)	(2)%
Total (per Boe)	$ 46.64	$ 39.89	$ 6.75	17 %
Production volumes:				
Oil (MBbls)	2,531	1,383	1,148	83 %
Natural gas (MMcf)	2,139	1,136	1,003	88 %
NGLs (MBbls)	436	192	244	127 %
Total (MBoe)	3,323	1,765	1,558	88 %
Average daily production volume:				
Oil (Bbls/d)	27,507	15,036	12,471	83 %
Natural gas (Mcf/d)	23,245	12,346	10,899	88 %
NGLs (Bbls/d)	4,738	2,087	2,651	127 %
Total (Boe/d)	36,118	19,180	16,938	88 %

(1) Average prices shown in the table do not include settlements of commodity derivative transactions.

(2) On January 1, 2018, we adopted ASC 606. As a result of adoption, we changed the presentation of our natural gas and NGL sales revenues, with a corresponding change to our gathering and processing expense. For additional information regarding the new revenue recognition standard, see Note 2, *Significant Accounting Policies and Related Matters,* in "Part I. Financial Information - Item 1. Financial Statements." See the table below for a breakout of the impact on our revenues and expense of adopting ASC 606:

	Three Months Ended September 30, 2018		
(in thousands)	**Amounts presented on statements of operations**	**ASC 606 Adjustments**	**Previous Revenue Recognition Method**
Production revenues:			
Oil sales	$ 141,598	$ —	$ 141,598
Natural gas sales	2,552	1,102	3,654
NGL sales	10,814	3,604	14,418
Total production revenues	$ 154,964	$ 4,706	$ 159,670
Operating expenses:			
Gathering and processing expenses	$ —	$ 4,706	$ 4,706

As reflected in the table above, our total production revenue for the three months ended September 30, 2018 was 120%, or $84.6 million, higher than that of the same period from 2017. The increase is primarily due to higher sales volumes, along with higher realized commodity prices during the three months ended September 30, 2018. Our aggregate production volumes in the three months ended September 30, 2018 were 3,323 MBoe, comprised of 76% oil, 11% natural gas and 13% NGLs. This represents an increase of 88% over aggregate production volumes of 1,765 MBoe during the three months ended September 30, 2017.

The following table shows the effects of volume and price related changes on oil, natural gas and NGL sales from the three months ended September 30, 2017 to the three months ended September 30, 2018:

(in thousands)	Oil sales	Natural gas sales	NGL sales	Total
Three months ended September 30, 2017	$ 62,585	$ 2,939	$ 4,860	$ 70,384
Changes due to:				
Increase (decrease) in production volumes	51,910	2,607	6,172	60,689
Increase (decrease) in average realized prices (1)	27,103	(2,994)	(218)	23,891
Three months ended September 30, 2018	$ 141,598	$ 2,552	$ 10,814	$ 154,964

(1) The changes due to natural gas and NGL average realized prices were impacted by the adoption of ASC 606, as described above.

Operating Expenses

The following table summarizes our operating expenses for the periods indicated:

	Three Months Ended September 30,				Per Boe	
(in thousands, except per Boe)	2018	2017	Change	% Change	2018	2017
Lease operating expenses	$ 11,184	$ 5,184	$ 6,000	116 %	$ 3.37	$ 2.94
Gathering and processing expenses (1)	—	1,357	(1,357)	(100)%	$ —	$ 0.77
Production and ad valorem taxes	9,517	4,739	4,778	101 %	$ 2.86	$ 2.69
Exploration	23	6	17	283 %	$ 0.01	$ —
Depletion, depreciation, amortization and accretion	57,660	30,851	26,809	87 %	$ 17.35	$ 17.48
Impairment of unproved oil and natural gas properties	—	257	(257)	(100)%	NM	NM
Other operating expenses	19	41	(22)	(54)%	$ 0.01	$ 0.02
General and administrative (before equity-based compensation)	9,707	5,830	3,877	67 %	$ 2.92	$ 3.30
Total operating expenses (before equity-based compensation)	88,110	48,265	39,845	83 %	$ 26.52	$ 27.35
Equity-based compensation	2,614	11,903	(9,289)			
Total operating expenses	$ 90,724	$ 60,168	$ 30,556			

(1) On January 1, 2018, we adopted ASC 606 which changed the presentation of our natural gas and NGL sales revenues, with a corresponding change to our gathering and processing expense. See Note 2, *Significant Accounting Policies and Related Matters,* in "Part I. Financial Information - Item 1. Financial Statements" for more information, and the table in footnote 1 to the oil and natural gas revenues table, above, for a breakout of the impact on gathering and processing expense.

NM Not meaningful.

Lease Operating Expenses. Our lease operating expense ("LOE") varies in conjunction with our level of production, the timing of our workover expenses and variations in industry activity that cause fluctuations in service provider costs. LOE increased to $11.2 million in the three months ended September 30, 2018, compared to $5.2 million for the same period of 2017. The increase largely corresponds to our increased production and well counts between periods, resulting in overall higher costs for equipment rental and electricity. Additionally, during the three months ended September 30, 2018, we incurred approximately $2.7 million of additional workover expense as compared to the same period of 2017. LOE per Boe increased 15% to $3.37 for the three months ended September 30, 2018, as compared to the same period of 2017, primarily due to the additional workover costs, which may not fluctuate in conjunction with production levels.

Gathering and Processing Expenses. Gathering and processing expenses were $1.4 million in the three months ended September 30, 2017 and were reduced to $0 in the three months ended September 30, 2018 as a result of adopting ASC 606. During the three months ended September 30, 2018, $4.7 million of gathering and processing costs that previously would have been presented as expenses were deducted from revenues. Based on the sales contracts we currently have, all gathering and processing costs are deducted from revenue; however, future contracts could have different terms which may require us to record gathering and processing expense. For additional information regarding the adoption of ASC 606, see Note 2, *Significant Accounting Policies and Related Matters,* in “Part I. Financial Information - Item 1. Financial Statements.”

Production and Ad Valorem Taxes. Production and ad valorem taxes increased 101% between the three months ended September 30, 2017 and 2018, from $4.7 million in 2017 to $9.5 million in 2018. The increase in production taxes is due to an increase in revenues, and the increase in ad valorem taxes relates to the addition of multiple new high-volume wells.

Depletion, Depreciation, Amortization and Accretion. Depletion, depreciation, amortization and accretion (“DD&A”) expense increased $26.8 million, or 87%, during the three months ended September 30, 2018 compared to the same period of 2017. The increase in DD&A expense was largely due to an increase in production, partially offset by a slight decrease in our DD&A rate. Our DD&A rate can vary due to changes in proved reserve volumes, acquisition and disposition activity, development costs and impairments. The DD&A rate per Boe decreased 1% to $17.35 per Boe during the three months ended September 30, 2018, compared to $17.48 per Boe for the three months ended September 30, 2017.

General and Administrative and Equity-based Compensation. General and administrative expenses (“G&A”), excluding equity-based compensation, increased 67% to $9.7 million for the three months ended September 30, 2018, from $5.8 million for the same period of 2017. The increase is primarily due to a $3.0 million increase in costs related to salaries, employee benefits, contract personnel and other general business expenses required to support our development program and growing production levels. The number of our full-time employees increased from 56 at September 30, 2017 to 80 at September 30, 2018.

Equity-based compensation expense for the three months ended September 30, 2018 and 2017 is summarized as follows:

	Three Months Ended September 30,		
(in thousands)	**2018**	**2017**	**Change**
Incentive unit awards	$ 609	$ 10,692	$ (10,083)
Restricted stock unit awards	989	684	305
Performance stock unit awards	1,016	527	489
Total equity-based compensation expense	$ 2,614	$ 11,903	$ (9,289)

The decrease in equity-based compensation expense for incentive unit awards is due to the modification and acceleration of the awards allocated at the time of the IPO for accounting purposes in the first quarter of 2018. The remaining incentive unit award expense relates to awards not allocated at the time of the IPO. For additional information regarding our equity-based compensation, see Note 5, *Equity-based Compensation,* in “Part I. Financial Information - Item 1. Financial Statements.”

Other Income and Expense

The following table summarizes our other income and expenses for the periods indicated:

	Three Months Ended September 30,		
(in thousands)	**2018**	**2017**	**Change**
Gain (loss) on commodity derivatives	$ (96,516)	$ (27,693)	$ (68,823)
Interest expense, net	(8,256)	(467)	(7,789)
Gain on sale of assets	6,225	—	6,225
Other, net	12	60	(48)
Total other income (expense)	$ (98,535)	$ (28,100)	$ (70,435)

Gain (loss) on Commodity Derivatives. Net gains and losses on our derivative instruments are a function of fluctuations in the underlying commodity prices against our derivative instruments and monthly settlements, if any, of the instruments. To the extent the future commodity price outlook declines between measurement periods, we will generally have noncash mark-to-market gains, while to the extent future commodity price outlook increases between measurement periods, we will generally have noncash mark-to-market losses.

The following table sets forth the components of gain (loss) on commodity derivatives for the three months ended September 30, 2018 and 2017:

	Three Months Ended September 30,	
(in thousands)	2018	2017
Net cash receipts (payments) on settled derivatives	$ (6,347)	$ 3,195
Gain (loss) from the change in fair value of open derivative contracts, net	(90,169)	(30,888)
Gain (loss) on commodity derivatives	$ (96,516)	$ (27,693)

Interest Expense, net. The following table summarizes our interest expense for the three months ended September 30, 2018 and 2017:

	Three Months Ended September 30,	
(in thousands)	2018	2017
Amended and Restated Credit Facility (1)	$ 491	$ 392
Senior Notes	7,322	—
Amortization of debt issuance costs (2)	732	147
Capitalized interest	(289)	(72)
Interest expense, net	$ 8,256	$ 467

(1) Includes interest on outstanding balances and commitment fees on undrawn balances.
(2) Includes amortization of debt issuance costs on the Amended and Restated Credit Facility and Senior Notes.

The increase in interest expense on the Amended and Restated Credit Facility is due to increased commitment fees during the three months ended September 30, 2018, which corresponded to our increased elected borrowing base as compared to the same period of the prior year. Interest expense on the Senior Notes during the three months ended September 30, 2018 is a result of the issuance of the Senior Notes in May 2018.

Gain on Sale of Assets. The $6.2 million gain on sale of assets in the three months ended September 30, 2018 related to the sale of non-core unproved acreage.

Income tax expense (benefit)

During the three months ended September 30, 2018, we had an income tax benefit of $7.3 million, compared to a benefit of $2.6 million for the same period of 2017. The change is primarily due to a higher taxable net loss in 2018 compared to 2017, partially offset by the passage of the Tax Act, which reduced the U.S. corporate income tax rate from 35% in 2017 to 21% in 2018.

Comparison of the nine months ended September 30, 2018 versus September 30, 2017

Revenues

Oil and Natural Gas Revenues. The following table provides the components of our production revenues for the nine months ended September 30, 2018 and 2017, as well as each period's respective average realized prices and production volumes:

(in thousands or as indicated)	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017	Change	% Change
Production revenues:				
Oil sales	$ 410,935	$ 147,738	$ 263,197	178 %
Natural gas sales	7,765	5,697	2,068	36 %
NGL sales	23,721	9,041	14,680	162 %
Total production revenues	$ 442,421	$ 162,476	$ 279,945	172 %
Average realized price: (1) (2)				
Oil (per Bbl)	$ 59.15	$ 46.06	$ 13.09	28 %
Natural gas (per Mcf)	$ 1.29	$ 2.56	$ (1.27)	(50)%
NGLs (per Bbl)	$ 23.71	$ 22.28	$ 1.43	6 %
Total (per Boe)	$ 49.42	$ 40.78	$ 8.64	21 %
Production volumes:				
Oil (MBbls)	6,947	3,208	3,739	117 %
Natural gas (MMcf)	6,025	2,224	3,801	171 %
NGLs (MBbls)	1,001	406	595	147 %
Total (MBoe)	8,952	3,984	4,968	125 %
Average daily production volume:				
Oil (Bbls/d)	25,447	11,750	13,697	117 %
Natural gas (Mcf/d)	22,069	8,147	13,922	171 %
NGLs (Bbls/d)	3,665	1,486	2,179	147 %
Total (Boe/d)	32,790	14,594	18,196	125 %

(1) Average prices shown in the table do not include settlements of commodity derivative transactions.

(2) On January 1, 2018, we adopted ASC 606. As a result of adoption, we changed the presentation of our natural gas and NGL sales revenues, with a corresponding change to our gathering and processing expense. For additional information regarding the new revenue recognition standard, see Note 2, *Significant Accounting Policies and Related Matters,* in "Part I. Financial Information - Item 1. Financial Statements." See the table below for a breakout of the impact on our revenues and expense of adopting ASC 606:

(in thousands)	Nine Months Ended September 30, 2018: Amounts presented on statements of operations	ASC 606 Adjustments	Previous Revenue Recognition Method
Production revenues:			
Oil sales	$ 410,935	$ —	$ 410,935
Natural gas sales	7,765	2,987	10,752
NGL sales	23,721	8,205	31,926
Total production revenues	$ 442,421	$ 11,192	$ 453,613
Operating expenses:			
Gathering and processing expenses	$ —	$ 11,192	$ 11,192

As reflected in the table above, our total production revenue for the first nine months of 2018 was 172%, or $279.9 million, higher than that of the same period from 2017. The increase is primarily due to higher sales volumes, along with higher average realized commodity prices during the first nine months of 2018. Our aggregate production volumes in the first nine months of 2018 were 8,952 MBoe, comprised of 78% oil, 11% natural gas and 11% NGLs. This represents an increase of 125% over aggregate production volumes of 3,984 MBoe during the first nine months of 2017.

The following table shows the effects of volume and price related changes on oil, natural gas and NGL sales from the nine months ended September 30, 2017 to the nine months ended September 30, 2018:

(in thousands)	Oil sales	Natural gas sales	NGL sales	Total
Nine months ended September 30, 2017	$ 147,738	$ 5,697	$ 9,041	$ 162,476
Changes due to:				
Increase (decrease) in production volumes	172,262	9,719	13,249	195,230
Increase (decrease) in average realized prices (1)	90,935	(7,651)	1,431	84,715
Nine months ended September 30, 2018	$ 410,935	$ 7,765	$ 23,721	$ 442,421

(1) The changes due to natural gas and NGL average realized prices were impacted by the adoption of ASC 606, as described above.

Operating Expenses

The following table summarizes our operating expenses for the periods indicated:

	Nine Months Ended September 30,				Per Boe	
(in thousands, except per Boe)	2018	2017	Change	% Change	2018	2017
Lease operating expenses	$ 31,390	$ 10,684	$ 20,706	194 %	$ 3.51	$ 2.68
Gathering and processing expenses (1)	—	2,404	(2,404)	(100)%	$ —	$ 0.60
Production and ad valorem taxes	26,437	10,916	15,521	142 %	$ 2.95	$ 2.74
Exploration	24	14	10	71 %	$ —	$ —
Depletion, depreciation, amortization and accretion	160,552	67,224	93,328	139 %	$ 17.93	$ 16.87
Impairment of unproved oil and natural gas properties	53	365	(312)	(85)%	NM	NM
Other operating expenses	65	223	(158)	(71)%	$ 0.01	$ 0.06
General and administrative (before equity-based compensation)	28,800	17,862	10,938	61 %	$ 3.22	$ 4.48
Total operating expenses (before equity-based compensation)	247,321	109,692	137,629	125 %	$ 27.63	$ 27.53
Equity-based compensation	80,671	431,642	(350,971)			
Total operating expenses	$ 327,992	$ 541,334	$ (213,342)			

(1) On January 1, 2018, we adopted ASC 606 which changed the presentation of our natural gas and NGL sales revenues, with a corresponding change to our gathering and processing expense. See Note 2, *Significant Accounting Policies and Related Matters,* in "Part I. Financial Information - Item 1. Financial Statements" for more information, and the table in footnote 1 to the oil and natural gas revenues table, above, for a breakout of the impact on gathering and processing expense.

NM Not meaningful.

Lease Operating Expenses. Our LOE varies in conjunction with our level of production, the timing of our workover expenses and variations in industry activity that cause fluctuations in service provider costs. LOE increased to $31.4 million in the first nine months of 2018, compared to $10.7 million for the same period of 2017. The increase largely corresponds to our increased production and well counts between periods, resulting in higher overall costs for equipment rental, electricity, contract labor, and general maintenance and repair. Additionally, during the nine months ended September 30, 2018, we incurred approximately $9.5 million of additional workover expense, as compared to the same period of 2017. LOE per Boe increased 31% to $3.51 for the nine months ended September 30, 2018, primarily due to the additional workover costs, which may not fluctuate in conjunction with production levels.

Gathering and Processing Expenses. Gathering and processing expenses were $2.4 million in the first nine months of 2017 and were reduced to $0 in the first nine months of 2018 as a result of adopting ASC 606. During the first nine months of 2018, $11.2 million of gathering and processing costs that would have previously been presented as expenses were deducted from revenues. Based on the sales contracts we currently have, all gathering and processing costs are deducted from revenue; however, future contracts could have different terms which may require us to record gathering and processing expense. For additional information regarding the adoption of ASC 606, see Note 2, *Significant Accounting Policies and Related Matters,* in “Part I. Financial Information - Item 1. Financial Statements.”

Production and Ad Valorem Taxes. Production and ad valorem taxes increased 142% between the nine months ended September 30, 2017 and 2018, from $10.9 million in 2017 to $26.4 million in 2018. The increase in production taxes is due to an increase in revenues, and the increase in ad valorem taxes relates to the addition of multiple new high-volume wells.

Depletion, Depreciation, Amortization and Accretion. DD&A expense increased $93.3 million, or 139%, through the first nine months of 2018 compared to the same period of 2017. The increase in DD&A expense was largely due to an increase in production, as well as an increase in our DD&A rate. Our DD&A rate can vary due to changes in proved reserve volumes, acquisition and disposition activity, development costs and impairments. The DD&A rate per Boe increased 6% to $17.93 per Boe during the nine months ended September 30, 2018, compared to $16.87 per Boe for the first nine months of 2017. The increase in our DD&A rate was largely due to an increase in capitalized costs due to continued development activities, while the rate of increase in our reserve volumes related to those development activities was lower than the rate of capitalized costs increase.

General and Administrative and Equity-based Compensation. G&A, excluding equity-based compensation, increased 61% to $28.8 million for the nine months ended September 30, 2018, from $17.9 million for the same period of 2017. The increase is primarily due to a $6.8 million increase in costs related to salaries, employee benefits, contract personnel and other general business expenses required to support our development program and growing production levels, and a $3.5 million increase related to severance and other nonrecurring expenses primarily from the first quarter of 2018. The number of our full-time employees increased from 56 at September 30, 2017 to 80 at September 30, 2018.

Equity-based compensation expense for the nine months ended September 30, 2018 and 2017 is summarized as follows:

	Nine Months Ended September 30,		
(in thousands)	**2018**	**2017**	**Change**
Incentive unit awards	$ 75,767	$ 429,585	$ (353,818)
Restricted stock unit awards	3,391	1,191	2,200
Performance stock unit awards	1,513	866	647
Total equity-based compensation expense	$ 80,671	$ 431,642	$ (350,971)

Equity-based compensation expense for the nine months ended September 30, 2018 includes $71.3 million related to a modification of the service requirements in February 2018 for the incentive unit awards allocated at the IPO. For the nine months ended September 30, 2017, equity-based compensation expense of $431.6 million included (1) $379.0 million related to the vested shares of common stock at the IPO date, all of which was noncash except for $14.7 million related to a management incentive advance payment made in April 2016, and (2) $22.2 million related to a modification in conjunction with a March 2017 separation agreement of a former executive officer. We expect to recognize additional noncash compensation expense of approximately $5.4 million over approximately 2.4 years for the incentive unit awards, $7.9 million over approximately 2.2 years for RSU awards and $8.2 million over approximately 2.1 years for the PSU awards. For additional information regarding our equity-based compensation, see Note 5, *Equity-based Compensation,* in “Part I. Financial Information - Item 1. Financial Statements.”

Other Income and Expense

The following table summarizes our other income and expenses for the periods indicated:

	Nine Months Ended September 30,		
(in thousands)	**2018**	**2017**	**Change**
Gain (loss) on commodity derivatives	$ (110,426)	$ 15,922	$ (126,348)
Interest expense, net	(17,095)	(1,610)	(15,485)
Gain on sale of assets	6,225	—	6,225
Other, net	30	474	(444)
Total other income (expense)	$ (121,266)	$ 14,786	$ (136,052)

Gain (loss) on Commodity Derivatives. Net gains and losses on our derivative instruments are a function of fluctuations in the underlying commodity prices against our derivative instruments and monthly settlements, if any, of the instruments. To the extent the future commodity price outlook declines between measurement periods, we will generally have noncash mark-to-market gains, while to the extent future commodity price outlook increases between measurement periods, we will generally have noncash mark-to-market losses.

The following table sets forth the components of gain (loss) on commodity derivatives for the nine months ended September 30, 2018 and 2017:

	Nine Months Ended September 30,	
(in thousands)	**2018**	**2017**
Net cash receipts (payments) on settled derivatives	$ (33,705)	$ 3,691
Gain (loss) from the change in fair value of open derivative contracts, net	(76,721)	12,231
Gain (loss) on commodity derivatives	$ (110,426)	$ 15,922

Interest Expense, net. The following table summarizes our interest expense for the nine months ended September 30, 2018 and 2017:

	Nine Months Ended September 30,	
(in thousands)	**2018**	**2017**
Amended and Restated Credit Facility (1)	$ 4,528	$ 1,338
Senior Notes	11,668	—
Amortization of debt issuance costs (2)	1,753	407
Capitalized interest	(854)	(135)
Interest expense, net	$ 17,095	$ 1,610

(1) Includes interest on outstanding balances and commitment fees on undrawn balances.
(2) Includes amortization of debt issuance costs on the Amended and Restated Credit Facility and the Senior Notes.

The increase in interest expense on our Amended and Restated Credit Facility is primarily due to an increase in the weighted average outstanding balance on our credit facility of $116.2 million during the nine months ended September 30, 2018, compared to $19.2 million during the same period of 2017. The increase is also attributable to increased commitment fees that resulted from our increased elected borrowing base. Interest expense on the Senior Notes during the nine months ended September 30, 2018 is a result of the issuance of the Senior Notes in May 2018.

Gain on Sale of Assets. The $6.2 million gain on sale of assets in the nine months ended September 30, 2018 related to the sale of non-core unproved acreage.

Income tax expense (benefit)

Income tax expense decreased to $14.7 million during the nine months ended September 30, 2018, from $101.0 million for the same period of 2017. Income tax expense during the nine months ended September 30, 2018 was unaffected by $71.3 million in incentive unit award equity-based compensation expense in February 2018, which is not deductible for federal or state income tax purposes. Income tax expense during the nine months ended September 30, 2017 primarily resulted from the $79.1 million income tax expense recorded in the first quarter of 2017 as a result of our change in tax status as part of the corporate reorganization. The decrease in income tax expense from 2017 to 2018 was also impacted by the passage of the Tax Act which reduced the U.S. corporate income tax rate from 35% in 2017 to 21% in 2018, partially offset by higher taxable net income during the nine months ended September 30, 2018 compared to the same period of 2017.

Liquidity and Capital Resources

Historically, our primary sources of liquidity were capital contributions from equity owners, including the IPO, borrowings under our credit facility and cash flows from operations. During the first nine months of 2018, our primary sources of liquidity were the proceeds from the Senior Notes offering of $488.4 million, borrowings on our credit facility of $165.0 million and cash flows from operations of $317.7 million. Our primary uses of cash have been the development and acquisition of oil, natural gas and NGL properties, the development of water sourcing and disposal infrastructure and a repayment on our credit facility of $320.0 million. As we pursue reserve and production growth, we continually monitor what capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future success in growing proved reserves, production and balancing the long-term development of our assets with a focus on generating attractive corporate level returns will be highly dependent on the capital resources available to us.

Capital Expenditures

Capital expenditures for oil and gas acquisitions, exploration, development and infrastructure activities are summarized below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Acquisitions				
Proved properties	$ —	$ —	$ —	$ —
Unproved properties (1)	6,321	7,845	17,647	56,364
Development costs	151,797	158,870	535,590	399,057
Infrastructure costs	6,693	3,613	14,463	21,805
Exploration costs	23	6	24	14
Total oil and gas capital expenditures	$ 164,834	$ 170,334	$ 567,724	$ 477,240

(1) Relates to oil and natural gas mineral interest leasing activity.

For the nine months ended September 30, 2018 and 2017, our capital expenditures have been focused on the development of our properties in the southern Delaware Basin. As of September 30, 2018, we had approximately 90,400 gross (78,900 net) acres.

The following table reflects wells that began producing in the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
Gross wells				
Operated	10	11	36	32
Non-operated	1	3	13	5
	11	14	49	37
Net wells				
Operated	9.8	10.2	33.5	30.9
Non-operated	0.1	1.4	5.1	1.9
	9.9	11.6	38.6	32.8

At September 30, 2018, we were in the process of drilling four gross (4.0 net) wells and had seven gross (6.9 net) wells waiting on completion, including three gross (2.9 net) wells that were in process of being completed.

2018 Capital Budget

Our 2018 capital budget for development of oil and gas properties and infrastructure is as follows:

(in millions)					
Drilling and completion	$	650.0	—	$	680.0
Water infrastructure		18.0	—		22.0
Total	$	668.0	—	$	702.0

Our 2018 capital budget excludes potential leasehold and/or surface acreage additions. Based on our 2018 capital budget, we expect to bring online 45 to 47 gross operated wells. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities and commodity prices.

Because we operate a high percentage of our acreage, capital expenditure amounts and timing are largely discretionary and within our control. We determine our capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners. A deferral of planned capital expenditures, particularly with respect to drilling and completing new wells, could result in a reduction in anticipated production and cash flows. Additionally, if we curtail our drilling program, we may lose a portion of our acreage through lease expirations. Furthermore, we may be required to remove some portion of our reserves currently booked as proved undeveloped reserves if such a deferral of planned capital expenditures means we will be unable to develop such reserves within five years of their initial booking.

Based on current expectations, we believe we have sufficient liquidity through our existing cash balances, cash flow from operations and additional borrowing capacity under our credit facility to execute our remaining 2018 capital program and anticipated 2019 capital expenditures, excluding potential acquisitions. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. If we require additional capital funding for capital expenditures, acquisitions or other reasons, we may seek such capital through borrowings under our credit facility, joint venture partnerships, production payment financings, asset sales, offerings of debt and equity securities or other means. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our future drilling program. We are actively seeking partners to assist in developing a portion of our Big Tex acreage. If we are unable to come to an agreement with a partner or otherwise arrange for the co-development of this acreage position, we may elect not to drill some or all of the wells required under our lease obligations which could result in a noncash impairment of our undeveloped assets in the Big Tex project area. In addition, if we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or replace our reserves.

Working Capital

Our working capital, which we define as current assets minus current liabilities, fluctuates primarily as a result of our realized commodity prices, increases or decreases in our production volumes, changes in receivables and payables related to our operating and development of oil and natural gas activities, changes in our hedging activities and changes in our cash and cash equivalents. At September 30, 2018, we had a working capital deficit of $77.7 million, a reduction of $35.7 million compared to a working capital deficit of $113.4 million at December 31, 2017. The decreased deficit is primarily the result of an $84.4 million increase in our cash balance, which increased primarily due to the net proceeds from the Senior Notes offering in May 2018, net of repayment of our then outstanding balance on our credit facility and underwriter and other offering fees. Additionally, we experienced an increase of $16.9 million related to increased JIB and other accounts receivable. These increases to our current assets were partially offset by a net increase in current derivative liabilities of $42.7 million, primarily related to the decrease in fair value of our derivative contracts expected to settle over the next 12 months. Further offsetting our increased current assets, accrued interest increased $11.3 million primarily due to our 5.875% Senior Notes, current liabilities associated with ongoing development activities increased $6.7 million and our revenue receivables, net of the related payable, decreased $5.8 million.

We may incur additional working capital deficits in the future due to future increases in liabilities related to our drilling program or further decreases in the value of our current commodity derivatives. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash and cash equivalents balance totaled approximately $93.9 million and $9.5 million at September 30, 2018 and December 31, 2017, respectively. We expect that our cash flows from operating activities, access to capital markets and availability under our credit facility will be sufficient to fund our working capital needs. We expect that our timing of receivables and payables, pace of development, production volumes, commodity and differentials to NYMEX prices for our oil and natural gas production will be the largest variables affecting our working capital.

Cash Flows

The following table summarizes our cash flows for the periods indicated:

	Nine Months Ended September 30,	
(in thousands)	**2018**	**2017**
Net cash provided by operating activities	$ 317,747	$ 105,428
Net cash used in investing activities	$ (564,781)	$ (413,135)
Net cash provided by financing activities	$ 331,450	$ 299,880

Operating Activities. Net cash provided by operating activities is primarily affected by production volumes, the price of oil, natural gas and NGLs, and changes in working capital.

The $212.3 million increase in the first nine months of 2018 compared to 2017 primarily resulted from a $280.2 million increase in revenues, which resulted from a 125% increase in volumes and a 21% increase in the average price received per Boe. This was partially offset by $33.7 million of higher cash operating costs primarily due to increased production, and $10.9 million of increased cash G&A costs largely due to additional personnel, severance and other nonrecurring expenses.

Investing Activities. Cash flows from investing activities primarily consist of the acquisition, exploration, and development of oil and natural gas properties, net of dispositions of oil and natural gas properties.

During the first nine months of 2018, net cash flow used in investing activities was $564.8 million, which included investments in developing our acreage of $551.1 million and leasehold and acquisition costs of $18.9 million. In the first nine months of 2017, net cash used for investing activities of $413.1 million included $349.2 million and $60.6 million for the development and acquisition of oil and natural gas properties, respectively.

Financing Activities. Net cash provided by financing activities includes the issuance of equity and debt transactions.

Net cash provided by financing activities during the first nine months of 2018 was primarily due to $488.4 million of net proceeds from the Senior Notes offering, which was partially offset by a net repayment on our credit facility of $155.0 million. Net cash provided by financing activities in the first nine months of 2017 was primarily due to $401.6 million of net proceeds from the sale of common stock in the IPO and a net repayment of $97.0 million on our credit facility.

Senior Secured Revolving Credit Facility

At December 31, 2017, the Amended and Restated Credit Facility had a borrowing base of $425.0 million, with $155.0 million outstanding under the credit facility, and $270.0 million in unused borrowing capacity. In March 2018, we entered into Amendment No. 2 to the Amended and Restated Credit Facility which extended the maturity date of the Amended and Restated Credit Facility to March 21, 2023, increased the borrowing base to $540.0 million, increased the hedging limits and lowered the pricing grid.

In April 2018, and in connection with the issuance of the Senior Notes, the lenders of the Amended and Restated Credit Facility agreed to waive a provision that would require a borrowing base reduction as a result of the Senior Notes. As a result, the borrowing base of the Amended and Restated Credit Facility continued to be $540.0 million. We also voluntarily elected to reduce the elected commitments to $475.0 million, effective as of the closing of the Senior Notes offering. Additionally, a portion of the proceeds from the Senior Notes were used to repay the entire outstanding balance under the Amended and Restated Credit Facility of $320.0 million as of the date the Senior Notes proceeds were received.

In June 2018, we entered into Amendment No. 3 to the Amended and Restated Credit Facility which increased the amount we are permitted to hedge up to 85% of forecasted future production for up to 36 months in the future, and up to the greater of 75% of our proved reserves and 60% of our reasonably anticipated forecasted production for 37 to 60 months in the future, provided that no hedges have a term beyond five years.

In August 2018, we entered into Amendment No. 4 to the Amended and Restated Credit Facility, which increased the borrowing base to $825.0 million and we increased our elected commitments to $540.0 million. In November 2018, we entered into Amendment No. 5 to the Amended and Restated Credit Facility, which increased the borrowing base to $900.0 million while our elected commitments remained at $540.0 million. As of the date of this filing, the Company has nothing outstanding and $540.0 million available under the Amended and Restated Credit Facility.

The amount available to be borrowed under our Amended and Restated Credit Facility is subject to a borrowing base that is subject to semiannual borrowing base redeterminations on or around April 1 and October 1 of each year by the lenders at their sole discretion. Additionally, at our option, we may request up to two additional redeterminations per year, to be effective on or about January 1 and July 1, respectively. The borrowing base depends on, among other things, the volumes of our proved reserves, estimated cash flows from those reserves, our commodity hedge positions and any other outstanding debt. Upon a redetermination of the borrowing base, if borrowings in excess of the revised borrowing capacity are outstanding, we could be required to immediately repay a portion of the debt outstanding under our credit facility.

At September 30, 2018, we were obligated to pay a commitment fee on unused amounts of our Amended and Restated Credit Facility of 0.375% to 0.50% per year on the unused portion of the elected commitments, depending on the relative amount of the loan outstanding in relation to the elected commitments. We may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

Our Amended and Restated Credit Facility contains restrictive covenants that limit our ability to, among other things:

- incur additional indebtedness;
- incur liens;
- make investments;
- make loans to others;
- merge or consolidate with another entity;
- sell assets;
- make certain payments;
- enter into transactions with affiliates;
- hedge interest rates; and
- engage in certain other transactions without the prior consent of the lenders.

The Amended and Restated Credit Facility contains financial covenants, which are measured on a quarterly basis. The covenants, as defined in the Amended and Restated Credit Facility, include requirements to comply with the following financial ratios:

Financial Covenant	Required Ratio			
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than	1.0	to	1.0
Ratio of debt to EBITDAX, as defined in the credit agreement	Not greater than	4.0	to	1.0

As of September 30, 2018, we were in compliance with all financial covenants.

Contractual Obligations

A summary of our contractual obligations as of September 30, 2018 is provided in the following table:

	Remainder	Payments Due by Period for the Year Ending December 31,						
(in thousands)	of 2018	2019	2020	2021	2022	2023	Thereafter	Total
Senior notes—principal	$ —	$ —	$ —	$ —	$ —	$ —	$ 500,000	$ 500,000
Senior notes—interest (1)	14,116	29,375	29,375	29,375	29,375	29,375	73,438	234,429
Operating leases (2)	142	1,509	1,532	1,553	1,559	1,589	7,378	15,262
Service and purchase contracts (3)	2,871	6,751	1,285	750	—	—	—	11,657
Rig contracts (4)	8,912	41,494	31,355	—	—	—	—	81,761
Frac fleet contracts (5)	7,800	—	—	—	—	—	—	7,800
Total	$ 33,841	$ 79,129	$ 63,547	$ 31,678	$ 30,934	$ 30,964	$ 580,816	$ 850,909

(1) Interest represents the scheduled cash payments on the Senior Notes.
(2) Primarily relates to the lease of our corporate office.

(3) Primarily relates to a coiled tubing service agreement and a retail power purchase agreement.
(4) Relates to four operated drilling rigs running, two of which were released in October 2018 with no penalties incurred. As of September 30, 2018, we had signed four new rig contracts that are expected to begin running during the fourth quarter of 2018. If we were to terminate these contracts at September 30, 2018, including all rigs running and contracted, we would be required to pay early termination penalties of approximately $44.1 million.
(5) Relates to two frac fleets under contract at September 30, 2018. If the fleets were not able to be reassigned, we would be required to pay termination fees of $3.2 million as of September 30, 2018.

Off-Balance Sheet Arrangements

We had no material off-balance sheet arrangements as of September 30, 2018. Please read Note 10, *Commitments and Contingencies*, in "Part I. Financial Information - Item 1. Financial Statements" for a discussion of our commitments and contingencies, some of which are not recognized in the balance sheets under GAAP.

Critical Accounting Policies and Estimates

Our management makes a number of significant estimates, assumptions and judgments in the preparation of our financial statements. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates" in our 2017 Annual Report on Form 10-K for a discussion of the estimates and judgments necessary in our accounting for impairment of oil and natural gas properties, oil, natural gas and NGL reserve quantities and standardized measure of discounted future net cash flows, derivative instruments, and income taxes. Any new accounting policies or updates to existing accounting policies as a result of new accounting pronouncements have been included in the notes to our consolidated and combined financial statements contained in this Quarterly Report on Form 10-Q. The application of our critical accounting policies may require management to make judgments and estimates about the amounts reflected in the consolidated and combined financial statements. Management uses historical experience and all available information to make these estimates and judgments. Different amounts could be reported using different assumptions and estimates.

Recent Accounting Pronouncements

Please refer to Note 2, *Significant Accounting Policies and Related Matters - Recent Accounting Pronouncements,* in "Part I. Financial Information - Item 1. Financial Statements" for a discussion of recent accounting pronouncements and their anticipated effect on our business.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following market risk disclosures should be read in conjunction with "Item 7A. Qualitative and Quantitative Disclosures About Market Risk" contained in our 2017 Form 10-K.

Market risk refers to potential losses from adverse changes in market prices and rates. We are exposed to market risk primarily in the form of commodity price risk and interest rate risk. In order to manage exposure to commodity price risk, we use commodity derivative financial instruments, including swaps and basis swaps. Our objective is to reduce fluctuations in revenue, net income and cash flows resulting from changes in commodity prices. We do not enter into derivative or other financial instruments for speculative trading purposes.

Hypothetical changes in commodity prices and interest rates chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in interest rates and commodity prices, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil, natural gas and NGL production. Pricing for oil, natural gas and NGLs has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for our oil, natural gas and NGL production depend on numerous factors beyond our control.

The following table shows how hypothetical changes in the realized prices we receive for our commodity sales would have impacted revenue for the nine months ended September 30, 2018:

(in thousands)	Revenue	% of Total	Sensitivity Analysis: Change in Realized Prices	Sensitivity Analysis: Impact on Revenue
Oil	$ 410,935	93%	+ / - $1.00 per barrel	+ / - $ 6,947
Natural gas	7,765	2%	+ / - $0.10 per Mcf	+ / - $ 603
NGL	23,721	5%	+ / - $1.00 per barrel	+ / - $ 1,001
Total [1]	$ 442,421	100%		

(1) Our oil, natural gas and NGL revenues do not include the effects of derivatives instruments.

To reduce our exposure to changes in the prices of commodities, we have entered into, and may in the future enter into, commodity derivative instruments for a portion of our oil production for the years 2018 through 2020. The agreements entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil production over a fixed period of time. Our commodity derivative instruments are recorded at fair value and thus changes to the future commodity prices will have an impact on net income. During the nine months ended September 30, 2018 we recorded a loss on derivatives of $110.4 million, compared to a gain of $15.9 million for the same period from 2017.

The fair value of our derivative instruments is determined based on valuation models. We did not change our valuation method for our derivative instruments during the nine months ended September 30, 2018. The following table reconciles the changes that occurred in the fair values of our derivative instruments from December 31, 2017 to September 30, 2018:

(in thousands)	Commodity Derivative Instruments Net Assets (Liabilities)
Fair value of open contracts at December 31, 2017	$ (52,851)
Change in fair value of open contracts	(110,426)
Net cash payments on settled derivatives	33,705
Fair value of open contracts at September 30, 2018	$ (129,572)

The following table sets forth the hypothetical impact on the fair value of our net oil derivative liability of $129.6 million as of September 30, 2018, using an average increase or decrease of 10% to the commodity prices:

(in thousands)	Change to Prices: 10% Increase	Change to Prices: 10% Decrease
Increase (decrease) to net oil derivative liability as of September 30, 2018	$ 78,592	$ (78,592)

Our commodity derivative instruments allow us to reduce, but not eliminate, the potential variability in cash flow from operations due to fluctuations in oil prices. These instruments provide only partial price protection against declines in oil prices and may partially limit our potential gains from future increases in prices. In the future, we may use commodity derivatives to hedge a portion of our natural gas or NGL production.

Our commodity derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. The counterparties to our derivative contracts currently in place have investment grade ratings and are all lenders of our Amended and Restated Credit Facility.

See Note 3, *Derivative Instruments*, and Note 9, *Fair Value Measurements*, in “Part I. Financial Information - Item 1. Financial Statements” for a summary of our open derivative positions, as well as a discussion of how we determine the fair value of and account for our derivative contracts.

Interest Rate Risk

We are exposed to market risk related to changes in interest rates, which affects the amount of interest we pay on certain of our borrowings and the amount of interest we earn on our short-term investments.

As of September 30, 2018, we had no significant investments other than cash and cash equivalents; therefore, we were not exposed to material interest rate risk on investments.

Prior to paying down the outstanding balance on our Amended and Restated Credit Facility to $0 in May 2018, we were exposed to changes in interest rates as a result of our Amended and Restated Credit Facility. As of September 30, 2018, we had $500.0 million aggregate principal of fixed-rate long-term debt outstanding, net of unamortized debt issuance costs, with a fixed interest rate of 5.875%. Although near term changes in interest rates may impact the fair value of our fixed-rate debt, they do not expose us to interest rate risk or cash flow loss. Therefore, we have no exposure to fluctuating interest rates as of September 30, 2018.

We do not currently have any derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness. For additional information regarding our debt instruments, refer to Note 4, *Debt*, in "Part I. Financial Information - Item 1. Financial Statements."

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

In accordance with Rules 13a-15(b) of the Securities Exchange Act of 1934 (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 September 30, 2018. 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 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 that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of September 30, 2018 at the reasonable assurance level. Any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objective and management necessarily applies its judgment in evaluating the cost-benefit relationship of all possible controls and procedures.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) that occurred during the period covered by this Quarterly Report on Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

We are party to lawsuits arising in the ordinary course of our business. We cannot predict the outcome of any such lawsuits with certainty, but management believes it is remote that pending or threatened legal matters will have a material adverse impact on our financial condition.

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

Item 1A. Risk Factors

Our business faces many risks. Any of the risk factors discussed in this report or our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operation. For a discussion of our potential risks and uncertainties, see the information in Part I, Item 1A, Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2017 and Item 8.01, Other Events, in our Current Report on Form 8-K filed with the SEC on April 23, 2018. There have been no material changes to our risk factors from those described in our Annual Report on Form 10-K for the year ended December 31, 2017 and our Current Report on Form 8-K filed with the SEC on April 23, 2018.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Recent sales of unregistered securities

None.

Purchases of equity securities by the issuer and affiliated purchasers

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit Number	Description of Exhibit
*10.1	Amendment No. 4 to Amended and Restated Credit Agreement, dated as of August 9, 2018, among Jagged Peak Energy LLC, as borrower, the guarantors party named therein, Wells Fargo Bank, National Association, as administrative agent and as issuing lender, the lenders named therein, the assignors named therein, and the assignees named therein.
*31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**32.1	Certifications by Chief Executive Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.
**32.2	Certifications by Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.
*101.INS	XBRL Instance Document
*101.SCH	XBRL Schema Document
*101.CAL	XBRL Calculation Linkbase Document
*101.LAB	XBRL Label Linkbase Document
*101.PRE	XBRL Presentation Linkbase Document
*101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

† Compensatory plan or arrangement.
* Filed herewith.
** Furnished herewith.

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.

JAGGED PEAK ENERGY INC.

Date:	November 8, 2018	By:	/s/ JAMES J. KLECKNER	
			Name:	James J. Kleckner
			Title:	*Chief Executive Officer and President*
Date:	November 8, 2018	By:	/s/ ROBERT W. HOWARD	
			Name:	Robert W. Howard
			Title:	*Executive Vice President, Chief Financial Officer*
Date:	November 8, 2018	By:	/s/ SHONN D. STAHLECKER	
			Name:	Shonn D. Stahlecker
			Title:	*Controller*

Exhibit 10.1

EXECUTION VERSION

AMENDMENT NO. 4, MASTER ASSIGNMENT, AND AGREEMENT TO AMENDED AND RESTATED CREDIT AGREEMENT

This Amendment No. 4, Master Assignment, and Agreement to Amended and Restated Credit Agreement (this " Agreement") dated as of August 9, 2018 (the "Effective Date"), is among Jagged Peak Energy LLC, a Delaware limited liability company (the "Borrower"), Jagged Peak Energy Inc., a Delaware corporation (the "Guarantor"), Wells Fargo Bank, National Association, as administrative agent (in such capacity, the " Administrative Agent") and as issuing lender (in such capacity, the "Issuing Lender"), the Lenders (as defined below), the Assignors (as defined below), and the Assignees (as defined below).

RECITALS

A. Reference is made to that certain Amended and Restated Credit Agreement dated as of February 1, 2017 (as amended, supplemented or otherwise modified by that certain Amendment No. 1, Master Assignment and Agreement to Amended and Restated Credit Agreement dated as of October 26, 2017, Amendment No. 2, Limited Waiver, Master Assignment, and Agreement to Amended and Restated Credit Agreement dated as of March 21, 2018, Limited Consent and Agreement dated as of April 20, 2018, Amendment No. 3 to Amended and Restated Credit Agreement dated as of June 15, 2018, and as further amended, restated, supplemented, or otherwise modified from time to time, the "Credit Agreement") among the Borrower, the Administrative Agent, the Issuing Lender and the financial institutions party thereto as lenders from time to time (the "Lenders"). Each term defined in the Credit Agreement and used herein without definition shall have the meaning assigned to such term in the Credit Agreement, unless expressly provided to the contrary.

B. Subject to the terms and conditions set forth herein, (i) Deutsche Bank AG New York Branch (the " Exiting Lender") has agreed to assign all of its rights and obligations to the other Lenders, (ii) the Lenders, other than the Exiting Lender (each an "Existing Lender" and collectively, the "Existing Lenders") wish to reallocate the percentage of their rights and obligations under the Credit Agreement as a Lender among themselves as set forth on Schedule I hereto, and (iii) the Existing Lenders have agreed to increase the Borrowing Base from $540,000,000 to $825,000,000, subject to their increased Aggregate Elected Commitments (as set forth on Schedule I hereto) of $540,000,000.

C. The parties hereto wish to (i) increase the Borrowing Base and the Aggregate Elected Commitments, and (ii) amend the Credit Agreement as set forth herein.

THEREFORE, the parties hereto hereby agree as follows:

Section 1. **Defined Terms; Other Definitional Provisions**. As used in this Agreement, each of the terms defined in the opening paragraph and the Recitals above shall have the meanings assigned to such terms therein. Article, Section, Schedule, and Exhibit references are to Articles and Sections of and Schedules and Exhibits to this Agreement, unless otherwise specified. The words "hereof", "herein", and "hereunder" and words of similar import when used in this Agreement shall refer to this Agreement as a whole and not to any particular provision of this Agreement. The term "including" means "including, without limitation,". Paragraph headings have been inserted in this Agreement as a matter of convenience for reference only and it is agreed that such paragraph headings are not a part of this Agreement and shall not be used in the interpretation of any provision of this Agreement.

Section 2. **Master Assignment**. In lieu of executing and delivering an Assignment and Assumption, each of the Exiting Lender and the Existing Lenders whose Pro Rata Share of the Commitments is decreasing in connection herewith (each an "Assignor" and, collectively, the "Assignors") and each Existing Lender whose Pro Rata Share of the Commitments is increasing in connection herewith (each an "Assignee" and, collectively, the "Assignees") hereby agree to, and Borrower hereby accepts, the following:

(a) Assignment. For an agreed consideration, each Assignor hereby irrevocably sells and assigns to the respective Assignees, and each Assignee hereby irrevocably purchases and assumes from the respective Assignors, subject to and in accordance with the terms hereof and the Credit Agreement, as of the Effective Date (i) such Pro Rata

Share in and to all of the respective Assignors' rights and obligations in their respective capacities as Existing Lenders under the Credit Agreement and any other documents or instruments delivered pursuant thereto to the extent related to the amount and Pro Rata Share identified in Schedule I hereto that would result in Assignors and Assignees having the respective Commitments (and applicable Pro Rata Share thereof) set forth in Schedule I attached hereto (including without limitation any letters of credit and guaranties provided in connection with the Credit Agreement), and (ii) to the extent permitted to be assigned under applicable law, all claims, suits, causes of action and any other right of the respective Assignors (in their respective capacities as Exiting Lender or Existing Lenders, as the case may be) against any Person, whether known or unknown, arising under or in connection with the Credit Agreement, any other documents or instruments delivered pursuant thereto or the loan transactions governed thereby or in any way based on or related to any of the foregoing, including, but not limited to, contract claims, tort claims, malpractice claims, statutory claims and all other claims at law or in equity related to, and in proportion to, the rights and obligations sold and assigned pursuant to clause (i) above (the rights and obligations sold and assigned by any Assignor to any Assignee pursuant to clauses (i) and (ii) above being referred to herein collectively as an "Assigned Interest" and referenced on Schedule I). Each such sale and assignment is without recourse to any Assignor and, except as expressly provided in this Agreement, without representation or warranty by any Assignor. Notwithstanding anything else provided herein and for the avoidance of doubt, after giving effect hereto and the assignments and the assumptions contemplated hereby, the Exiting Lender shall have no Commitment or Elected Commitment under, or Pro Rata Share in respect of, the Credit Agreement and shall not be listed in Schedule I hereto.

(b) Representations and Warranties of Assignor. Each Assignor (i) represents and warrants that (A) it is the legal and beneficial owner of the relevant Assigned Interest, (B) such Assigned Interest is free and clear of any lien, encumbrance or other adverse claim, and (C) it has full power and authority, and has taken all action necessary, to execute and deliver this Agreement and to consummate the transactions contemplated hereby; and (ii) assumes no responsibility with respect to (A) any statements, warranties or representations made in or in connection with the Credit Agreement or any other Credit Document, (B) the execution, legality, validity, enforceability, genuineness, sufficiency or value of the Credit Documents or any collateral thereunder, (C) the financial condition of the Borrower, its Subsidiaries or Affiliates or any other Person obligated in respect of any Credit Document or (D) the performance or observance by the Borrower, its Subsidiaries or Affiliates or any other Person of any of its obligations under any Credit Document.

(c) Representations and Warranties of Assignee. Each Assignee (i) represents and warrants that (A) it has full power and authority, and has taken all action necessary, to execute and deliver this Agreement and to consummate the transactions contemplated hereby and to become (or remain, as the case may be) a Lender under the Credit Agreement, (B) it meets all the requirements to be an assignee under Section 10.7 of the Credit Agreement (subject to such consents, if any, as may be required under Section 10.7 of the Credit Agreement), (C) from and after the Effective Date, it shall be bound by the provisions of the Credit Agreement as a Lender thereunder and, to the extent of the relevant Assigned Interest, shall have the obligations of a Lender thereunder, (D) it is sophisticated with respect to decisions to acquire assets of the type represented by the Assigned Interest and either it, or the person exercising discretion in making its decision to acquire the Assigned Interest, is experienced in acquiring assets of such type, (E) it has received a copy of the Credit Agreement and has received or has been accorded the opportunity to receive copies of the most recent financial statements delivered pursuant to Section 5.2 thereof, and such other documents and information as it deems appropriate to make its own credit analysis and decision to enter into this Agreement and to purchase such Assigned Interest, (F) it has, independently and without reliance upon the Administrative Agent or any Lender and based on such documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Agreement and to purchase such Assigned Interest, and (G) if it is not incorporated under the laws of the United States of America or a state thereof, on or prior to the date hereof, it has delivered to the Administrative Agent any documentation required to be delivered by it pursuant to the terms of the Credit Agreement, duly completed and executed by such Assignee; and (ii) agrees that (A) it will, independently and without reliance on the Administrative Agent, any Assignor, or any other Lenders, and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking action under the Credit Documents, and (B) it will perform in accordance with their terms all of the obligations which by the terms of the Credit Documents are required to be performed by it as a Lender.

(d) Payments. From and after the Effective Date, the Administrative Agent shall make all payments in respect of each Assigned Interest (including payments of principal, interest, fees and other amounts) to the relevant

Assignee whether such amounts have accrued prior to, on or after the Effective Date. The Assignors and Assignees shall make all appropriate adjustments in payments by the Administrative Agent for periods prior to the Effective Date or with respect to the making of this assignment directly between themselves.

(e) Consent; Waiver of Administrative Fees. The Administrative Agent, the Issuing Lender and the Borrower hereby consent to each Assignor's assignment of the Assigned Interests to the respective Assignees, and waive any other conditions to the effectiveness of such assignment that are not expressly set forth in this Agreement, and agree that the terms of this Agreement shall constitute an Assignment and Assumption. The Administrative Agent hereby consents to a one-time waiver of the $3,500 administrative fees that would otherwise be payable by each Assignee pursuant to Section 10.7(b)(iv) of the Credit Agreement as a result of the assignment provided for herein.

Section 3. **Amendment to Credit Agreement**. Schedule I of the Credit Agreement is hereby amended and restated in its entirety in the form attached hereto as Schedule I. The information set forth in the column "Elected Commitment" on such amended Schedule I is hereby deemed to satisfy the requirement that the applicable Existing Lenders deliver an Elected Commitment Increase Certificate in accordance with Section 2.1(d) of the Credit Agreement.

Section 4. **Borrowing Base Increase**. Subject to the terms of this Agreement, the parties hereto hereby agree that, as of the Effective Date, the Borrowing Base is hereby increased from $540,000,000 to $825,000,000, and the Borrowing Base shall remain in effect at such amount until the Borrowing Base is redetermined or adjusted in accordance with the Credit Agreement, as amended hereby. The redetermination of the Borrowing Base pursuant to this Section 4 shall constitute the Quarterly Redetermination to occur on or about July 1, 2018, as provided in Section 2.2(c)(iii) of the Credit Agreement.

Section 5. **Representations and Warranties.** Each Credit Party represents and warrants that, as of the date hereof (after giving effect to the Waiver): (a) the representations and warranties of such Credit Party contained in the Credit Agreement and in the other Credit Documents are true and correct in all material respects (except that such materiality qualifier shall not be applicable to any representations and warranties that already are qualified or modified by materiality in the text thereof) on and as of the Effective Date as if made on and as of such date, except that any representation and warranty which by its terms is made as of a specified date is true and correct in all material respects (except that such materiality qualifier shall not be applicable to any representations and warranties that already are qualified or modified by materiality in the text thereof) only as of such specified date; (b) no Default has occurred and is continuing; (c) the execution, delivery and performance of this Agreement are within such Credit Party's powers and have been duly authorized by all necessary corporate, limited liability company, or partnership action; (d) this Agreement constitutes the legal, valid, and binding obligation of such Credit Party enforceable against such Credit Party in accordance with its terms, except as limited by applicable bankruptcy, insolvency, reorganization, moratorium, or similar laws affecting the rights of creditors generally and general principles of equity whether applied by a court of law or equity; (e) the execution, delivery and performance of this Agreement by such Credit Party do not require any authorization or approval or other action by, or any notice or filing with, any Governmental Authority other than those that have been obtained or provided and other than filings delivered hereunder to perfect Liens created under the Security Documents; and (f) the Liens under the Security Documents are valid and subsisting and secure the obligations under the Credit Documents.

Section 6. **Conditions to Effectiveness.** This Agreement shall become effective on the Effective Date and enforceable against the parties hereto upon the occurrence of the following conditions precedent:

(a) The Administrative Agent shall have received multiple original counterparts, as requested by the Administrative Agent, of this Agreement, duly and validly executed and delivered by duly authorized officers of the Borrower, the Guarantor, the Administrative Agent, the Issuing Lender, each of the Lenders, the Assignors, and the Assignees.

(b) The Administrative Agent shall have received an amended and restated Note payable to each Lender requesting an amended and restated Note in the amount of its Commitment, after giving effect to this Agreement, duly and validly executed and delivered by a duly authorized officer of the Borrower.

(c) The Borrower shall have paid (i) to the Administrative Agent all reasonable out-of-pocket costs and expenses that have been invoiced and are payable pursuant to Section 10.1 of the Credit Agreement and (ii) all other fees and expenses as agreed in writing.

(d) The Administrative Agent shall have received duly executed Mortgages, or supplements to existing Mortgages, in form and substance reasonably satisfactory to the Administrative Agent, encumbering not less than 90% (by PV10) of the Credit Parties' Proven Reserves and 90% (by PV10) of the Credit Parties' PDP Reserves, in each case, as described in the most recently delivered Engineering Report.

(e) The Administrative Agent shall have received satisfactory title information and be satisfied in its sole discretion with the title to the Oil and Gas Properties included in the Borrowing Base, and that such Oil and Gas Properties constitute (i) not less than 80% (by PV10) of the Credit Parties' Proven Reserves evaluated in the most recently delivered Engineering Report and (ii) that the Credit Parties have good and marketable title to their Oil and Gas Properties, subject to no other Liens (other than Permitted Liens).

(f) The Administrative Agent shall have received the following, duly executed by all the parties thereto, as applicable, in form and substance reasonably satisfactory to the Administrative Agent and the Lenders:

(i.) a certificate from a Responsible Officer of the Borrower and the Parent dated as of the Effective Date stating that as of such date (A) all representations and warranties of any Credit Party set forth in this Agreement and in each of the other Credit Documents are true and correct in all material respects (except that such materiality qualifier shall not be applicable to any representations and warranties contained in Section 4.20 of the Credit Agreement and any representations and warranties that already are qualified or modified by materiality in the text thereof) on such date, except that any representation and warranty which by its terms is made as of a specified date shall be required to be true and correct in all material respects (except that such materiality qualifier shall not be applicable to any representations and warranties contained in Section 4.20 of the Credit Agreement and any representations and warranties that already are qualified or modified by materiality in the text thereof) only as of such specified date, (B) no Default has occurred and is continuing and (C) the secretary's certificate delivered in connection with the Credit Agreement remains, with respect to the Borrower and the Guarantor, true and correct in all material respects;

(ii.) certificates of good standing for each Credit Party in each state in which each such Person is organized or qualified to do business, which certificate shall be (A) dated a date not earlier than 10 days prior to the Effective Date or (B) otherwise effective on the Effective Date;

(iii.) a legal opinion of Vinson & Elkins, L.L.P. as outside counsel to the Credit Parties, in form and substance reasonably acceptable to the Administrative Agent; and

(iv.) appropriate UCC-3 financing statements, if any, necessary or desirable for filing with the appropriate authorities and any other documents, agreements, or instruments necessary to create, perfect or maintain an Acceptable Security Interest in the Collateral described in the Security Agreement;

(g) The Credit Parties shall have received any consents, licenses and approvals required in accordance with applicable law, or in accordance with any document, agreement, instrument or arrangement to which such Credit Party is a party, in connection with the execution, delivery, performance, validity and enforceability of this Agreement and the other Credit Documents.

(h) No action, suit, investigation or other proceeding (including without limitation, the enactment or promulgation of a statute or rule) by or before any arbitrator or any Governmental Authority shall be threatened or pending and no preliminary or permanent injunction or order by a state or federal court shall have been entered (i) in connection with this Agreement, any other credit agreement, or any transaction contemplated hereby or thereby or (ii) which could reasonably be expected to result in a Material Adverse Change.

(i) The Administrative Agent shall have received such other documents, governmental certificates, agreements, and lien searches as the Administrative Agent or any Lender may reasonably request.

Section 7. **Acknowledgments and Agreements**.

(a) Each Credit Party acknowledges that on the date hereof all outstanding Secured Obligations are payable in accordance with their terms and each Credit Party waives any set-off, counterclaim, recoupment, defense, or other right, in each case, existing on the date hereof, with respect to such Secured Obligations. Each party hereto does hereby adopt, ratify, and confirm the Credit Agreement, as amended hereby, and acknowledges and agrees that the Credit Agreement, as amended hereby, is and remains in full force and effect, and each Credit Party acknowledges and agrees that its respective liabilities and obligations under the Credit Agreement, as amended herby, and the other Credit Documents are not impaired in any respect by this Agreement.

(b) The Administrative Agent, the Issuing Lender, and the Lenders hereby expressly reserve all of their rights, remedies, and claims under the Credit Documents. Nothing in this Agreement shall constitute a waiver or relinquishment of (i) any Default or Event of Default under any of the Credit Documents, (ii) any of the agreements, terms or conditions contained in any of the Credit Documents, (iii) any rights or remedies of the Administrative Agent, the Issuing Lender, or any Lender with respect to the Credit Documents, or (iv) the rights of the Administrative Agent, the Issuing Lender, or any Lender to collect the full amounts owing to them under the Credit Documents.

(c) This Agreement is a Credit Document for the purposes of the provisions of the other Credit Documents. Without limiting the foregoing, any breach of representations, warranties, and covenants under this Agreement shall be a Default or Event of Default, as applicable, under the Credit Agreement.

Section 8. **Reaffirmation of the Guaranty**. The Guarantor hereby ratifies, confirms, acknowledges and agrees that its obligations under Article IX of the Credit Agreement are in full force and effect and that the Guarantor continues to unconditionally and irrevocably guarantee the full and punctual payment, when due, whether at stated maturity or earlier by acceleration or otherwise, of all the Guaranteed Obligations (as defined in Section 9.1(a) of the Credit Agreement), and its execution and delivery of this Agreement does not indicate or establish an approval or consent requirement by the Guarantor under Article IX of the Credit Agreement or otherwise, in connection with the execution and delivery of amendments, consents or waivers to the Credit Agreement or any of the other Credit Documents.

Section 9. **Reaffirmation of Liens**. Each Credit Party (a) reaffirms the terms of and its obligations (and the security interests granted by it) under each Security Document to which it is a party, and agrees that each such Security Document will continue in full force and effect to secure the Secured Obligations as the same may be amended, supplemented, or otherwise modified from time to time, and (b) acknowledges, represents, warrants and agrees that the Liens and security interests granted by it pursuant to the Security Documents are valid, enforceable and subsisting and create an Acceptable Security Interest to secure the Secured Obligations.

Section 10. **Counterparts.** This Agreement may be executed in any number of counterparts and by different parties hereto in separate counterparts, each of which when so executed shall be deemed to be an original and all of which taken together shall constitute one and the same agreement. Delivery of an executed counterpart of a signature page of this Agreement by facsimile or in electronic (i.e., "pdf" or "tif") format shall be effective as delivery of a manually executed counterpart of this Agreement.

Section 11. **Successors and Assigns.** This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns permitted pursuant to the Credit Agreement.

Section 12. **Severability.** In case one or more of the provisions of this Agreement shall for any reason be invalid, illegal or unenforceable in any respect under any applicable law, the validity, legality and enforceability of the remaining provisions contained herein or in the other Credit Documents shall not be affected or impaired thereby.

Section 13. **<u>Governing Law</u>.** This Agreement shall be deemed to be a contract made under and shall be governed by and construed in accordance with the laws of the State of New York without regard to conflicts of laws principles (other than Sections 5-1401 and 5-1402 of the General Obligations Law of the State of New York).

Section 14. **<u>Entire Agreement</u>. This Agreement, the Credit Agreement, the Notes, and the other Credit Documents constitute the entire understanding among the parties hereto with respect to the subject matter hereof and supersede any prior agreements, written or oral, with respect thereto.**

[The remainder of this page has been left blank intentionally.]

EXECUTED to be effective as of the date first above written.

BORROWER:

JAGGED PEAK ENERGY LLC

By:	/s/ CHRISTOPHER HUMBER
Name:	Christopher Humber
Title:	Executive Vice President, General Counsel and Secretary

GUARANTOR:

JAGGED PEAK ENERGY INC.

By:	/s/ CHRISTOPHER HUMBER
Name:	Christopher Humber
Title:	Executive Vice President, General Counsel and Secretary

ADMINSTRATIVE AGENT/ISSUING LENDER/LENDER:

WELLS FARGO BANK, NATIONAL ASSOCIATION, as Administrative Agent, Issuing Lender, and an Existing Lender

By:	/s/ ZACHARY KRAMER
Name:	Zachary Kramer
Title:	Vice President

LENDERS:

FIFTH THIRD BANK, as an Existing Lender

By: /s/ JONATHAN H. LEE
Name: Jonathan H. Lee
Title: Director

ABN AMRO CAPTIAL USA LLC, as an Existing Lender

By: /s/ DARRELL HOLLEY
Name: Darrell Holley
Title: Managing Director

By: /s/ MICHAELA BRAUN
Name: Michaela Braun
Title: Director

KEYBANK NATIONAL ASSOCIATION, as an Existing Lender

By:	/s/ GEORGE E. MCKEAN
Name:	George E. McKean
Title:	Senior Vice President

FIRST TENNESSEE BANK NATIONAL ASSOCIATION,
as an Existing Lender

By: /s/ JOHN B. LANE
Name: John B. Lane
Title: Executive Vice President

CITIBANK, N.A., as an Existing Lender

By: /s/ CLIFF VAZ

Name: Cliff Vaz

Title: Vice President

JPMORGAN CHASE BANK, N.A., as an Existing Lender

By: /s/ DAVID MORRIS
Name: David Morris
Title: Authorized Officer

GOLDMAN SACHS BANK USA, as an Existing Lender

By: /s/ JAMIE MINIERI

Name: Jamie Minieri

Title: Authorized Signatory

UBS AG, STAMFORD BRANCH, as an Existing Lender

By: /s/ DARLENE ARIAS
Name: Darlene Arias
Title: Director

By: /s/ NIMA GANDHI
Name: Nima Gandhi
Title: Associate Director

BMO HARRIS BANK N.A., as an Existing Lender

By: /s/ MELISSA GUZMANN
Name: Melissa Gusmann
Title: Director

ROYAL BANK OF CANADA, as an Existing Lender and an Assignee

By:	/s/ KRISTAN SPIVEY
Name:	Kristen Spivey
Title:	Authorized Signatory

COMERICA BANK, as an Existing Lender

By: /s/ JEFFREY M. LABAUVE
Name: Jeffrey M. LaBauve
Title: Vice President

DEUTSCHE BANK AG NEW YORK BRANCH, solely as the Existing Lender and Assignor for purposes of Section 2 hereof

By: /s/ ALICIA SCHUG
Name: Alicia Schug
Title: Vice President

By: /s/ MARGUERITE SUTTON
Name: Marguerite Sutton
Title: Vice President

U.S. BANK NATIONAL ASSOCIATION, as an Existing Lender

By:	/s/ JOHN C. LOZANO
Name:	John C. Lozano
Title:	Senior Vice President

BOKF, NA, as an Existing Lender

By:	/s/ SONJA BORODKO
Name:	Sonja Borodko
Title:	Senior Vice President

SCHEDULE I

Commitments, Contact Information

ADMINISTRATIVE AGENT/ ISSUING LENDER		
Wells Fargo Bank, National Association	**Address**:	1700 Lincoln St., 6th Floor Denver, CO 80203
	Attn:	Oleg Kogan
	Telephone:	303-863-5367
	Facsimile:	303-863-5196
	Email:	Oleg.Kogan@wellsfargo.com
CREDIT PARTIES		
Borrower/Guarantors	**Address**:	1401 Lawrence Street Suite 1800
	Attn:	Bob Howard
	Telephone:	720-215-3660
	Facsimile:	720-215-3690
	Email:	bhoward@jaggedpeakenergy.com

Lender	Commitment	Elected Commitment	Pro Rata Share
Wells Fargo Bank, National Association	$173,611,111.11	$62,500,000.00	11.57407407%
Fifth Third Bank	$145,833,333.33	$52,500,000.00	9.72222222%
ABN AMRO Capital USA LLC	$145,833,333.33	$52,500,000.00	9.72222222%
Citibank, N.A.	$145,833,333.33	$52,500,000.00	9.72222222%
JPMorgan Chase Bank, N.A.	$145,833,333.33	$52,500,000.00	9.72222222%
KeyBank National Association	$145,833,333.33	$52,500,000.00	9.72222222%
Royal Bank of Canada	$111,111,111.12	$40,000,000.00	7.4074074%
Goldman Sachs Bank USA	$97,222,222.22	$35,000,000.00	6.48148148%
UBS AG, Stamford Branch	$97,222,222.22	$35,000,000.00	6.48148148%
First Tennessee Bank National Association	$83,333,333.33	$30,000,000.00	5.55555556%
BMO Harris Bank N.A.	$55,555,555.56	$20,000,000.00	3.70370370%
Comerica Bank	$55,555,555.56	$20,000,000.00	3.70370370%
U.S. Bank National Association	$55,555,555.56	$20,000,000.00	3.70370370%
BOKF, NA	$41,666,666.67	$15,000,000.00	2.77777778%
Total:	**$1,500,000,000.00**	**$540,000,000.00**	**100%**

Exhibit 31.1

CERTIFICATION OF THE PRINCIPAL EXECUTIVE OFFICER

I, James J. Kleckner, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Jagged Peak 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; and

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

5) The registrant's other certifying 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):

   a) 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

   b) 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: November 8, 2018

/s/ JAMES J. KLECKNER

Name: James J. Kleckner

Title: Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION OF THE PRINCIPAL FINANCIAL OFFICER

I, Robert W. Howard, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Jagged Peak 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; and

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

5) The registrant's other certifying 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):

    a) 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

    b) 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: November 8, 2018

/s/ ROBERT W. HOWARD

Name: Robert W. Howard

Title: Executive Vice President and Chief Financial Officer

Exhibit 32.1

Certification

In connection with the Quarterly Report of Jagged Peak Energy Inc. (the "Company") on Form 10-Q for the quarter ended September 30, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), James J. Kleckner, Chief Executive Officer and President, does hereby certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), that:

1. 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); and

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

Date: November 8, 2018

/s/ JAMES J. KLECKNER

Name: James J. Kleckner

Title: Chief Executive Officer and President

Exhibit 32.2

Certification

In connection with the Quarterly Report of Jagged Peak Energy Inc. (the "Company") on Form 10-Q for the quarter ended September 30, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Robert W. Howard, Executive Vice President and Chief Financial Officer, does hereby certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), that:

1. 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); and

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

Date:	November 8, 2018	/s/ ROBERT W. HOWARD	
		Name:	Robert W. Howard
		Title:	Executive Vice President and Chief Financial Officer