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 June 30, 2019
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	**81-3943703**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification Number)
1401 Lawrence Street, Suite 1800	
Denver, Colorado	**80202**
(Address of principal executive offices)	(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 ☑

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

Title of each class	Ticker Symbol	Name of each exchange on which registered
Common stock, par value $0.01 per share	JAG	New York Stock Exchange

The registrant had 213,403,812 shares of common stock outstanding at August 2, 2019.

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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.

Unproved properties. Lease acreage with no proved reserves.

Waha Hub. A natural gas delivery point in Pecos County, Texas that serves as a benchmark for natural gas.

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, 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 2019;
- 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, including our ability to satisfy minimum gross volume commitments under certain marketing agreements;
- our future drilling plans;
- 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, 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 the above mentioned Form 10-K or 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 BALANCE SHEETS
(Unaudited)
(in thousands, except share data)

	June 30, 2019	December 31, 2018
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 24,796	$ 35,229
Accounts receivable	59,913	61,186
Derivative instruments	21,948	103,092
Prepaid and other current assets	3,619	1,627
Total current assets	110,276	201,134
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, successful efforts method	2,229,708	1,905,498
Accumulated depletion	(506,241)	(386,883)
Total oil and gas properties, net	1,723,467	1,518,615
Other property and equipment, net	10,664	11,670
Total property and equipment, net	1,734,131	1,530,285
OTHER NONCURRENT ASSETS		
Operating lease right-of-use assets	56,211	—
Derivative instruments	10,297	31,899
Other assets	3,454	3,823
Total noncurrent assets	69,962	35,722
TOTAL ASSETS	$ 1,914,369	$ 1,767,141
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 27,096	$ 34,762
Accrued liabilities	127,620	130,012
Operating lease liabilities	35,877	—
Derivative instruments	36,193	23,208
Total current liabilities	226,786	187,982
LONG-TERM LIABILITIES		
Long-term debt	639,904	489,239
Derivative instruments	9,387	11,162
Asset retirement obligations	2,436	1,946
Deferred income taxes	109,835	124,418
Operating lease liabilities	24,780	—
Other long-term liabilities	—	4,444
Total long-term liabilities	786,342	631,209
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, 213,393,773 shares issued at June 30, 2019; 213,187,780 shares issued at December 31, 2018	2,134	2,132
Additional paid-in capital	863,088	856,818
Retained Earnings (Accumulated deficit)	36,019	89,000
Total stockholders' equity	901,241	947,950
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,914,369	$ 1,767,141

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

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

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
REVENUES				
Oil sales	$ 145,624	$ 148,614	$ 269,114	$ 269,337
Natural gas sales	(2,041)	2,338	177	5,213
NGL sales	3,174	7,599	7,052	12,907
Other operating revenues	—	125	9	272
Total revenues	146,757	158,676	276,352	287,729
OPERATING EXPENSES				
Lease operating expenses	15,554	10,486	29,204	20,206
Production and ad valorem taxes	11,535	9,246	20,837	16,920
Exploration	—	1	—	1
Depletion, depreciation, amortization and accretion	61,222	54,915	120,296	102,892
Impairment of unproved oil and natural gas properties	862	—	946	53
General and administrative expenses (including equity-based compensation of $3,993 and $2,379 for the three months ended June 30, 2019 and 2018, respectively, and $6,927 and $78,057 for the six months ended June 30, 2019 and 2018, respectively)	13,078	10,833	26,472	97,150
Other operating expenses	6	24	3,206	46
Total operating expenses	102,257	85,505	200,961	237,268
INCOME (LOSS) FROM OPERATIONS	44,500	73,171	75,391	50,461
OTHER INCOME (EXPENSE)				
Gain (loss) on commodity derivatives	18,469	(9,584)	(125,123)	(13,910)
Interest expense, net	(9,263)	(6,108)	(17,709)	(8,839)
Other, net	(137)	10	(123)	18
Total other income (expense)	9,069	(15,682)	(142,955)	(22,731)
INCOME (LOSS) BEFORE INCOME TAX	53,569	57,489	(67,564)	27,730
Income tax expense (benefit)	11,662	12,408	(14,583)	22,052
NET INCOME (LOSS)	$ 41,907	$ 45,081	$ (52,981)	$ 5,678
Net income (loss) per common share:				
Basic	$ 0.20	$ 0.21	$ (0.25)	$ 0.03
Diluted	$ 0.20	$ 0.21	$ (0.25)	$ 0.03
Weighted average common shares outstanding:				
Basic	213,371	213,142	213,321	213,073
Diluted	213,519	213,262	213,321	213,169

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

JAGGED PEAK ENERGY INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Unaudited)
(in thousands)

	Common Stock								
	Shares		Amount		Additional Paid-in Capital		Retained Earnings (Accumulated Deficit)		Total Stockholders' Equity
BALANCE AT DECEMBER 31, 2018	213,188	$	2,132	$	856,818	$	89,000	$	947,950
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	167		2		(281)		—		(279)
Equity-based compensation	—		—		2,934		—		2,934
Net income (loss)	—		—		—		(94,888)		(94,888)
BALANCE AT MARCH 31, 2019	213,355		2,134		859,471		(5,888)		855,717
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	39		—		(376)		—		(376)
Equity-based compensation	—		—		3,993		—		3,993
Net income (loss)	—		—		—		41,907		41,907
BALANCE AT JUNE 30, 2019	213,394	$	2,134	$	863,088	$	36,019	$	901,241
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	180		2		(202)		—		(200)
Equity-based compensation	—		—		75,678		—		75,678
Net income (loss)	—		—		—		(39,403)		(39,403)
BALANCE AT MARCH 31, 2018	213,111		2,131		849,150		(115,861)		735,420
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	68		1		—		—		1
Equity-based compensation	—		—		2,379		—		2,379
Net income (loss)	—		—		—		45,081		45,081
BALANCE AT JUNE 30, 2018	213,179	$	2,132	$	851,529	$	(70,780)	$	782,881

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

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

	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$ (52,981)	$ 5,678
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion expense	120,296	102,892
Impairment of unproved oil and natural gas properties	946	53
Amortization of debt issuance costs	1,176	1,021
Deferred income taxes	(14,583)	22,052
Equity-based compensation	6,927	78,057
(Gain) loss on commodity derivatives	125,123	13,910
Net cash receipts (payments) on settled derivatives	(11,167)	(27,358)
Other	(7)	(156)
Change in operating assets and liabilities:		
Accounts receivable and other current assets	(719)	(18,549)
Accounts payable and accrued liabilities	(6,764)	22,214
Net cash provided by operating activities	168,247	199,814
CASH FLOWS FROM INVESTING ACTIVITIES		
Leasehold and acquisition costs	(15,567)	(11,053)
Development of oil and natural gas properties	(311,865)	(392,968)
Other capital expenditures	(452)	(1,881)
Net cash used in investing activities	(327,884)	(405,902)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from credit facility	150,000	165,000
Repayment of credit facility	—	(320,000)
Proceeds from senior notes	—	500,000
Debt issuance costs	(141)	(12,743)
Employee tax withholding for settlement of equity compensation awards	(655)	(200)
Net cash provided by financing activities	149,204	332,057
NET CHANGE IN CASH AND CASH EQUIVALENTS	(10,433)	125,969
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	35,229	9,523
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 24,796	$ 135,492
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION		
Interest paid, net of capitalized interest	$ 16,210	$ 3,813
Cash paid for income taxes	—	—
Cash paid for operating lease liabilities included in cash flows from operating activities	744	—
Cash paid for operating lease liabilities included in cash flows from investing activities	17,847	—
SUPPLEMENTAL DISCLOSURE OF NONCASH OPERATING ACTIVITIES		
Lease liabilities arising from obtaining right-of-use assets	$ 73,413	$ —
SUPPLEMENTAL DISCLOSURE OF NONCASH INVESTING ACTIVITIES		
Accrued capital expenditures	$ 105,101	$ 102,306
Asset retirement obligations	405	426

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

JAGGED PEAK ENERGY INC.

Notes to Consolidated Financial Statements
(Unaudited)

Note 1—Organization, Operations and Basis of Presentation

Organization and Operations

Jagged Peak Energy Inc. (either individually or together with its subsidiaries, 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.

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”). Additional background on the Company, its IPO and 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, 2018 (the “2018 Form 10-K”).

Basis of Presentation

The accompanying unaudited interim consolidated 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 2018 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 financial statements included in the 2018 Form 10-K. All significant intercompany 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 changes due to development activities, natural production declines, the uncertainty of exploration and development drilling results, the fair value of derivative instruments and other factors.

Certain prior year amounts have been reclassified to conform to the current presentation.

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 financial statements in its 2018 Form 10-K, and are supplemented by the notes to the consolidated 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 financial statements.

Use of Estimates

In the course of preparing the consolidated 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 financial statements include, among other things, (1) oil and natural gas reserve quantities, which impact depletion of oil and natural gas properties and impairment of proved oil and natural gas properties, (2) impairment of unproved oil and natural gas properties, which includes assumptions about future development and lease renewal, commodity price outlooks and prevailing market rates, (3) accrued operating and capital costs, (4) asset retirement obligation timing and costs, (5) lease terms and incremental borrowing rates used in the determination of lease assets and liabilities, (6) measurement of equity-based compensation, (7) fair value of derivative instruments, (8) deferred income taxes and (9) disclosure of commitments and contingencies. Changes in these estimates and assumptions could have a significant impact on results in future periods.

Revenue Recognition

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 from the Permian Basin. The Company believes the disaggregation of revenues into oil sales, natural gas sales and NGL sales, as seen on the consolidated statements of operations, is an appropriate level of detail for its primary activity.

Contract Assets and Liabilities. The Company's performance obligations for its contracts with customers are satisfied at a point in time through the delivery of oil and natural gas to its customers. Accordingly, the Company did not have any contract assets or liabilities as of June 30, 2019 and December 31, 2018.

Performance Obligations. 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. 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.

Accounts Receivable

At June 30, 2019 and December 31, 2018, accounts receivable was comprised of the following:

(in thousands)	June 30, 2019	December 31, 2018
Oil and gas sales	$ 44,435	$ 40,465
Joint interest	11,716	14,058
Other	3,762	6,663
Total accounts receivable	$ 59,913	$ 61,186

At June 30, 2019 and December 31, 2018, 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)	June 30, 2019	December 31, 2018
Proved oil and natural gas properties	$ 2,075,483	$ 1,746,766
Unproved oil and natural gas properties	154,225	158,732
Total oil and natural gas properties	2,229,708	1,905,498
Less: Accumulated depletion	(506,241)	(386,883)
Total oil and natural gas properties, net	$ 1,723,467	$ 1,518,615

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 June 30, 2019 and 2018, the Company recorded depletion for oil and natural gas properties of $60.7 million and $54.4 million, respectively. For the six months ended June 30, 2019 and 2018, the Company recorded depletion for oil and natural gas properties of $119.4 million and $101.8 million, respectively. Depletion expense is included in depletion, depreciation, amortization and accretion expense on the accompanying consolidated statements of operations.

Leases

Following the adoption of Accounting Standards Update ("ASU") 2016-02, *Leases (Topic 842)* on January 1, 2019, the Company determines if an arrangement is a lease at inception of the contract. Operating lease right-of-use ("ROU") assets and operating lease liabilities are recognized based on the present value of the future lease payments over the lease term at commencement date. For leases that do not provide implicit rates, the Company uses its incremental borrowing rate based on the information available at commencement date in determining the present value of future payments. Operating lease ROU assets exclude lease incentives and initial direct costs incurred. Operating lease cost is recognized on a straight-line basis over the lease term. The Company currently does not have any finance leases.

JAGGED PEAK ENERGY INC.

Notes to Consolidated Financial Statements
(Unaudited)

The Company has lease agreements with lease and non-lease components, which are all accounted for as a single lease component.

Short-term leases have a term of 12 months or less. The Company recognizes short-term lease cost on a straight-line basis over the lease term and does not record a ROU asset or lease liability for such leases.

The Company monitors for events or changes in circumstances that may require a reassessment or impairment of its leases, at which time the Company's ROU assets for operating leases may be reduced by impairment losses.

Accrued Liabilities

The components of accrued liabilities are shown below:

(in thousands)	June 30, 2019	December 31, 2018
Accrued capital expenditures	$ 80,218	$ 74,688
Accrued accounts payable	1,539	5,941
Royalties payable	15,400	19,964
Other current liabilities	30,463	29,419
Total accrued liabilities	$ 127,620	$ 130,012

Recent Accounting Pronouncements

Recently Adopted Accounting Standards

Leases. In February 2016, the Financial Accounting Standards Board ("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. ASU 2016-02 retains a distinction between operating and finance leases concerning the recognition and presentation of the expense and payments related to leases in the statements of operations and cash flows. Entities are required to recognize operating or finance leases as ROU assets and lease liabilities on the balance sheet as well as disclose key information about leasing arrangements in the notes to the financial statements. ROU assets represent the Company's right to use an underlying asset for the lease term and lease liabilities represent the Company's obligation to make lease payments arising from the lease. This ASU does not apply to leases of mineral rights to explore for or use oil and natural gas.

The Company adopted ASU 2016-02 on January 1, 2019, using the modified retrospective approach as permitted under ASU 2018-11, which allows the Company to apply the legacy lease guidance and disclosure requirements ("ASC 840") in the comparative periods presented for the year of adoption. The adoption did not require an adjustment to opening retained earnings for a cumulative effect adjustment.

As part of the adoption, the Company elected the short-term lease recognition policy election for all leases that qualify, and as such, no ROU assets or lease liabilities will be recorded on the balance sheet when the term of the lease is less than 12 months. The Company also elected the following practical expedients:

- the package of transition practical expedients, permitting the Company to not reassess its prior conclusions about lease identification, lease classification and initial direct costs;
- the practical expedient pertaining to land easements, which allows the new guidance to be applied prospectively to all new or modified land easements and rights-of-way; and
- the practical expedient to not separate lease and non-lease components.

The new lease standard impacted the Company's consolidated balance sheets as a result of the ROU assets and operating lease liabilities but did not impact its consolidated statements of operations or consolidated statements of cash flows. The Company currently has no finance leases. The impact to the opening January 1, 2019 consolidated balance sheets was as follows:

(in thousands)	Opening Balances as of January 1, 2019	Adoption of ASC 842	As Adjusted at January 1, 2019
Operating lease right-of-use assets [1]	$ —	$ 73,413	$ 73,413
Current operating lease liabilities [1]	$ —	$ 35,043	$ 35,043
Long-term operating lease liabilities [1]	—	42,814	42,814
Other long-term liabilities [2]	4,444	(4,444)	—

(1) Represents the recognition of operating lease ROU assets and the associated lease liabilities.
(2) Represents the derecognition of deferred rent and leasehold incentives that were accounted for under ASC 840.

Adoption of the new standard did not impact the Company's previously reported consolidated balance sheets, results of operations, cash flows statements or statements of changes in equity.

For more information on the Company's leases, refer to Note 10, *Leases*.

Accounting Standards Not Yet Adopted

Financial Instruments: Credit Losses. In June 2016, the FASB issued ASU 2016-13, *Financial Instruments-Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*, which replaces the current incurred loss methodology with an expected loss methodology. This new methodology requires that a financial asset measured at amortized cost be presented at the net amount expected to be collected. The update is intended to provide financial statement users with more useful information about expected credit losses on financial instruments. The amended standard is effective for the Company on January 1, 2020, with early adoption permitted, and will be applied using a modified retrospective approach which may result in a cumulative effect adjustment to retained earnings upon adoption. Historically, the Company's credit losses on oil and natural gas sales receivables and joint interest receivables have not been significant, and the Company does not believe the adoption of ASU 2016-13 will have a material impact on its consolidated financial statements.

Note 3—Derivative Instruments

Objectives and Strategies

The Company is exposed to fluctuations in commodity prices received for its oil and natural gas production. To mitigate the volatility in its expected operating cash flows, the Company hedges a portion of its crude oil sales through derivative instruments. The Company does not use these instruments for speculative or trading purposes.

Commodity Derivatives

In an effort to reduce the variability of the Company's cash flows, the Company hedges the commodity prices associated with a portion of its expected future oil volumes by entering into the following types of instruments:

Swaps. The Company receives a 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 Swaps. These instruments establish a fixed price differential between Cushing WTI prices and Midland WTI prices for the notional volumes contracted. The Company receives the fixed price differential and pays the floating market price differential to the counterparty.

The following table summarizes the Company's derivative contracts as of June 30, 2019:

Contract Period	Volumes (MBbls)	Wtd Avg Price ($/Bbl)
Oil Swaps: (1)		
Third quarter 2019	1,932	$ 59.95
Fourth quarter 2019	1,932	$ 59.95
Total 2019	3,864	$ 59.95
Year ending December 31, 2020	4,026	$ 60.60
Oil Basis Swaps: (2)		
Third quarter 2019	2,300	$ (4.79)
Fourth quarter 2019	2,300	$ (4.79)
Total 2019	4,600	$ (4.79)
Year ending December 31, 2020	9,516	$ (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.

Subsequent to June 30, 2019, the Company entered into the following additional derivative contracts:

Contract Period	Volumes (MBbls)	Wtd Avg Price ($/Bbl)
Oil Swaps: (1)		
Year ending December 31, 2020	2,196	$ 55.37

(1) The index prices for the oil swaps are based on the NYMEX–WTI monthly average futures price.

Counterparty Risk

By using derivative instruments to hedge exposure to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit 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.

At June 30, 2019, the Company had commodity derivative contracts with six counterparties, all of which were lenders, or affiliates of 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.

Should the creditworthiness of the Company's counterparties decline, under certain circumstances the Company may have a contractual right of offset against other amounts owed by the Company to the counterparty, but otherwise 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.

Financial Statement Presentation

The Company's derivative instruments are carried at fair value on the consolidated balance sheets. The Company has elected to not apply hedge accounting; 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.

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*.

Consolidated Statements of Operations

The Company recognized the following gains (losses) on derivative instruments in its consolidated statements of operations for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2019	2018	2019	2018
Net gain (loss) on settled derivative instruments	$ (8,697)	$ (11,879)	$ (11,167)	$ (27,358)
Net gain (loss) from the change in fair value of open derivative instruments	27,166	2,295	(113,956)	13,448
Gain (loss) on derivative instruments, net	$ 18,469	$ (9,584)	$ (125,123)	$ (13,910)

Consolidated Balance Sheets

The Company's derivative instruments 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 balance sheets.

The following tables present the amounts and classifications of the Company's commodity contract derivative assets and liabilities as of June 30, 2019 and December 31, 2018 (in thousands):

As of June 30, 2019:	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	$ 21,948	$ (19,604)	$ 2,344
Commodity contracts	Noncurrent assets - derivative instruments	10,297	(6,326)	3,971
Total assets		$ 32,245	$ (25,930)	$ 6,315
Liabilities				
Commodity contracts	Current liabilities - derivative instruments	$ 36,193	$ (19,604)	$ 16,589
Commodity contracts	Noncurrent liabilities - derivative instruments	9,387	(6,326)	3,061
Total liabilities		$ 45,580	$ (25,930)	$ 19,650

As of December 31, 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	$ 103,092	$ (18,815)	$ 84,277
Commodity contracts	Noncurrent assets - derivative instruments	31,899	(9,668)	22,231
Total assets		$ 134,991	$ (28,483)	$ 106,508
Liabilities				
Commodity contracts	Current liabilities - derivative instruments	$ 23,208	$ (18,815)	$ 4,393
Commodity contracts	Noncurrent liabilities - derivative instruments	11,162	(9,668)	1,494
Total liabilities		$ 34,370	$ (28,483)	$ 5,887

Note 4—Debt

The Company's debt consisted of the following at June 30, 2019 and December 31, 2018:

(in thousands)	June 30, 2019	December 31, 2018
Senior secured revolving credit facility	$ 150,000	$ —
5.875% senior unsecured notes due 2026	500,000	500,000
Debt issuance costs on senior unsecured notes	(10,096)	(10,761)
Total long-term debt	$ 639,904	$ 489,239

Senior Secured Revolving Credit Facility

At December 31, 2018, the Company's amended and restated credit facility, as amended (the "Amended and Restated Credit Facility"), had a borrowing base of $900.0 million with elected commitments of $540.0 million and nothing outstanding.

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 June 30, 2019, the Company was in compliance with its Amended and Restated Credit Facility financial covenants.

As of June 30, 2019, the borrowing base and elected commitments remained at $900.0 million and $540.0 million, respectively, and the Company had $150.0 million outstanding and $390.0 million of elected commitments available. The weighted-average interest rate as of June 30, 2019 was 4.12%.

5.875% Senior Unsecured Notes due 2026

JPE LLC has $500.0 million aggregate principal amount of 5.875% senior unsecured notes that mature on May 1, 2026 (the "Senior Notes"). Interest is payable on the Senior Notes semi-annually in arrears on each May 1 and November 1.

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 March 2019 the Company completed an offer to exchange the Senior Notes for registered, publicly tradable notes that have terms identical in all material respects to the Senior Notes (except that the exchange notes do not contain any transfer restrictions).

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:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Incentive unit awards	$ 548	$ 559	$ 1,194	$ 75,158
Restricted stock unit awards	1,671	794	2,896	2,113
Performance stock unit awards	1,625	892	2,584	497
Restricted stock unit awards issued to nonemployee directors	149	134	253	289
Equity-based compensation expense	$ 3,993	$ 2,379	$ 6,927	$ 78,057

Equity-based compensation expense, which is recorded in general and administrative expense in the accompanying consolidated 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 six months ended June 30, 2018, equity-based compensation expense included (1) $71.3 million related to a modification of the service requirements in February 2018 for the incentive unit awards allocated at the IPO and (2) the reversal of equity-based compensation expense associated with awards that were forfeited during the three months ended June 30, 2018, notably performance stock unit ("PSU") awards forfeited by former executive officers. As the Company's policy is to recognize forfeitures as they occur, previously recognized expense on unvested awards is reversed at the date of forfeiture.

The following table summarizes the Company's award activity for incentive units, restricted stock units ("RSU") and PSUs for the six months ended June 30, 2019:

	Incentive Units (2)	RSUs	PSUs
Unvested at December 31, 2018	5,397,555	871,119	691,363
Awards Granted (1)	28,991	1,056,517	616,901
Vested	(2,586,716)	(278,120)	—
Forfeited	(28,991)	(78,335)	(41,837)
Unvested at June 30, 2019	2,810,839	1,571,181	1,266,427

(1) The weighted average grant-date fair value was $8.27 for incentive units, $10.64 for RSUs and $12.63 for PSUs. The weighted average grant-date fair value for PSUs was calculated using a Monte Carlo simulation.

(2) Included in the unvested incentive units at June 30, 2019 are 2,404,830 units for which equity-based compensation expense was accelerated and fully recognized in February 2018.

The following table reflects the future equity-based compensation expense to be recorded for each type of award that was outstanding at June 30, 2019:

	Incentive Units	RSUs (1)	PSUs
Compensation costs remaining at June 30, 2019 (in millions)	$ 4.3	$ 15.0	$ 11.8
Weighted average remaining period at June 30, 2019 (in years)	1.8	2.3	2.1

(1) The remaining compensation cost at June 30, 2019 for the nonemployee director RSUs was $0.6 million, with a weighted average remaining period of 0.9 years.

Note 6—Earnings Per Share

Basic earnings per share 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. Shares to be issued in exchange for incentive units are already outstanding and will not have a dilutive effect upon vesting. 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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands, except per share amounts)	2019	2018	2019	2018
Net income (loss) attributable to common stock	$ 41,907	$ 45,081	$ (52,981)	$ 5,678
Basic weighted average shares outstanding	213,371	213,142	213,321	213,073
Dilutive unvested RSUs	31	115	—	96
Dilutive unvested PSUs	117	5	—	—
Diluted weighted average shares outstanding	213,519	213,262	213,321	213,169
Net income (loss) per common share:				
Basic	$ 0.20	$ 0.21	$ (0.25)	$ 0.03
Diluted	$ 0.20	$ 0.21	$ (0.25)	$ 0.03

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 antidilutive. These shares could dilute basic earnings per share in future periods.

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2019	2018	2019	2018
Number of antidilutive units: (1)				
Antidilutive unvested RSUs	1,305	121	1,351	342
Antidilutive unvested PSUs	225	1	650	165

(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 antidilutive.

Note 7—Income Taxes

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.

Income tax expense was as follows for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2019	2018	2019	2018
Income tax expense (benefit)	$ 11,662	$ 12,408	$ (14,583)	$ 22,052
Effective tax rate	21.8%	21.6%	21.6%	79.5%

For the six months ended June 30, 2018, the Company’s effective tax rate differed from 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.

Note 8—Asset Retirement Obligations

The following table summarizes the changes in the carrying amount of the asset retirement obligations for the six months ended June 30, 2019. The current portion of the asset retirement obligation liability is included in accrued liabilities on the consolidated balance sheets.

(in thousands)	
Asset retirement obligations at January 1, 2019	$ 2,072
Liabilities incurred and assumed	318
Liability settlements	(23)
Revisions of estimated liabilities	87
Accretion	96
Asset retirement obligations at June 30, 2019	2,550
Less current portion of asset retirement obligations	(114)
Long-term asset retirement obligations	$ 2,436

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 six months ended June 30, 2019.

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)	June 30, 2019	December 31, 2018
Assets from commodity derivative contracts	$ 32,245	$ 134,991
Liabilities due to commodity derivative contracts	$ 45,580	$ 34,370

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 balance sheets:

	June 30, 2019		December 31, 2018	
(in thousands)	Principal Amount	Fair Value	Principal Amount	Fair Value
Long-term debt:				
Senior secured revolving credit facility	$ 150,000	$ 150,000	$ —	$ —
5.875% senior unsecured notes due 2026	$ 500,000	$ 495,000	$ 500,000	$ 466,250

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 June 30, 2019 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 natural 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 considers 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 June 30,		Six Months Ended June 30,	
(in thousands)	2019	2018	2019	2018
Proved oil and natural gas property impairments	$ —	$ —	$ —	$ —
Unproved oil and natural gas property impairments (1)	862	—	946	53
	$ 862	$ —	$ 946	$ 53

(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—Leases

The Company's ROU assets include leases for its drilling rigs, its corporate headquarters and certain office equipment, with the significant lease types described below in more detail. As of June 30, 2019, the Company's leases have remaining lease terms of 0.8 years to 8.9 years. For purposes of calculating operating lease liabilities, lease terms may be deemed to include options to extend or terminate the lease when it is reasonably certain that the Company will exercise that option. The Company's lease agreements do not contain any material restrictive covenants. Additionally, the Company currently does not have any finance leases.

Short-term leases have a term of 12 months or less. The Company recognizes short-term lease cost based on usage of the asset over the lease term. There are no ROU assets or lease liabilities recorded for such leases.

Drilling Rigs. The Company enters into short- and long-term contracts for drilling rigs with third parties to support its development plan. The short-term drilling rig arrangements can range from a term that is in effect until drilling operations are completed on a contractually specified well or well pad, or for a given number of months not to exceed 12 months. The Company's long-term drilling contracts are generally structured with an initial noncancelable term of one to two years. Upon mutual agreement with the contractor, the Company typically has the option to extend the initial contract for additional wells, well pads or a contractually stated extension terms by providing 30 days' notice prior to the end of the original contract term.

The Company has determined that it cannot conclude with reasonable certainty that it will extend the drilling contracts past their respective primary term, and as a result, the Company uses the primary term in its calculation of the ROU asset and lease liability. The Company capitalizes the costs of its short- and long-term drilling rigs to oil and natural gas properties.

Corporate Headquarters. The Company leases office space from third parties for its corporate headquarters. The Company has determined that it cannot conclude with reasonable certainty that it will exercise any option to extend the contract past the noncancelable term. As such, the Company uses the noncancelable term in its calculation of the ROU asset and lease liability. The lease for the Company's corporate headquarters provides for increases in future minimum annual rental payments as defined in the lease agreement. The lease also includes real estate taxes and common area maintenance charges, which are expensed when occurred. The Company classifies its leases for office space as operating leases with the costs recognized as “general and administrative expenses” in its consolidated statements of operations.

Lease Costs

Lease cost for operating leases is recognized on a straight-line basis over the lease term. Short-term lease costs exclude expenses related to leases with a lease term of one month or less. Lease costs are presented gross and a portion of these costs will be reimbursed by the Company’s other working interest partners for their proportionate share. The total gross lease cost for the periods indicated are as follows:

(in thousands)	Three months ended June 30, 2019	Six months ended June 30, 2019
Operating lease cost [1]	$ 9,297	$ 18,594
Short-term lease cost [2]	3,841	28,279
Variable lease cost [3]	314	572
Total lease cost	$ 13,452	$ 47,445

(1) The total operating lease cost may not agree to the cash paid for operating lease liabilities on the consolidated statements of cash flows due to the timing of cash payments and incurred costs.
(2) Short-term lease cost during the three months ended June 30, 2019 is primarily related to one short-term drilling rig and certain field equipment. During the three months ended March 31, 2019, costs from the Company’s frac fleets were also included in this amount. During the three months ended June 30, 2019, the Company determined that the frac fleets are considered to have a term of one month or less and are no longer included in the short-term lease cost disclosure.
(3) Variable lease costs were not included in the measurement of the Company’s lease balances and primarily relate to common area maintenance charges on the Company’s corporate headquarters.

In accordance with the Company’s accounting policies, the Company’s share of these lease costs was either capitalized to oil and natural gas properties, or recorded within either general and administrative or lease operating expenses.

Lease Maturities

The table below reconciles the undiscounted lease payment maturities to the lease liabilities for the Company’s operating leases as of June 30, 2019:

	Remainder	Payments Due by Period for the Year Ending December 31,					
(in thousands)	of 2019	2020	2021	2022	2023	Thereafter	Total
Operating lease payments [1]	$ 18,900	$ 33,428	$ 1,547	$ 1,558	$ 1,589	$ 7,378	$ 64,400
Less: amount of lease payments representing interest							(3,743)
Present value of future minimum lease payments							60,657
Less: current operating lease liabilities							(35,877)
Long-term operating lease liabilities							$ 24,780

(1) The operating lease payments represent the total payment obligation to be incurred over the remaining life of the lease. A portion of these costs will be billed to the Company’s working interest partners when the payment is incurred based on the nature of the cost and the relative working interest of the working interest partner.

Supplemental Lease Information

Supplemental information related to the Company’s operating leases was as follows:

	June 30, 2019
Weighted average remaining lease term - operating leases (in years)	3.0
Weighted average discount rate - operating leases [1]	4.2%

(1) Upon adoption of the new lease standard, discount rates used for existing leases were established at January 1, 2019.

As of June 30, 2019, the Company’s future operating lease obligation that has not yet commenced is immaterial.

As described in Note 2, *Significant Accounting Policies and Related Matters*, the Company adopted ASU 2016-02 using the modified retrospective approach as permitted under ASU 2018-11. This ASU also requires entities electing this transition method to provide the required disclosures under ASC 840 for all periods that continue to be presented in accordance with ASC 840. As such, the Company included the future minimum payments for noncancelable operating leases as of December 31, 2018, in accordance with ASC 840, as follows:

(in thousands)	2019	2020	2021	2022	2023	Thereafter	Total
Operating leases	$ 1,547	$ 1,539	$ 1,553	$ 1,559	$ 1,589	$ 7,378	$ 15,165

In addition, lease payments associated with these operating leases were $0.5 million and $1.2 million for the three and six months ended June 30, 2018, respectively.

Note 11—Commitments and Contingencies

Commitments

There were no material changes in commitments during the first six months of 2019. Please refer to Note 10, *Commitments and Contingencies*, in the 2018 Form 10-K for additional discussion.

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 June 30, 2019 and December 31, 2018, the Company had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Note 12—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. No fees were paid by the Company to Trident during the three and six months ended June 30, 2019 and 2018.

During the second quarter of 2019, Quantum sold its interest in Oryx, at which point Oryx ceased to be a related party. As a result, transactions with Oryx that occurred subsequent to the date of sale are no longer considered related party transactions and are not included in the below disclosures.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2019	2018	2019	2018
Oryx via 3rd party shipper [1]	$ 7,216	$ 5,550	$ 14,041	$ 10,284
Oryx [2]	$ 384	$ 85	$ 516	$ 300
Phoenix [3]	$ 23	$ 112	$ 51	$ 221

(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 balance sheets. The Company also received $45 thousand from Oryx during the six months ended June 30, 2019 related to pipeline easements and right of way agreements.

(3) Fees paid to Phoenix are capitalized to proved properties on the consolidated balance sheets.

At June 30, 2019 and December 31, 2018, the Company had outstanding payables to these related parties of $21 thousand and $2.6 million, respectively. See Note 11, *Related Party Transactions*, in the 2018 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 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, 2018. The following discussion and analysis describes the principal factors affecting the Company's results of operations, liquidity, capital resources and contractual obligations. Additionally, the 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 and "Part 1, Item 1A. Risk Factors" in our 2018 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, Jagged Peak Energy LLC ("JPE LLC").

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. At June 30, 2019, our acreage position was approximately 78,100 net acres.

Summary of Operating and Financial Results for the Six Months Ended June 30, 2019

- Brought online 23 gross (22.2 net) wells;
- Increased average daily production from the first six months of 2018 by 20% to 37,462 Boe/d, comprised of 76% oil;
- Grew oil production 17% to 28,612 barrels per day, natural gas production by 16% to 24.9 MMcf/d and NGL production by 51% to 4,703 barrels per day compared to the first six months of 2018; and
- Impacted by negative natural gas revenues during the three months ended June 30, 2019 as a result of low and/or negative natural gas prices and the effect of gathering and processing costs.

Impact of Commodity Prices

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. Increases or decreases in our revenue and profitability 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, infrastructure build-out, seasonality and geopolitical and economic factors.

The prices we receive for our oil and natural gas production often reflect a discount to the relevant benchmark prices, such as the NYMEX–WTI oil price or the NYMEX–Henry Hub natural gas price. The difference between the benchmark price and the price we receive is called a differential. As of June 30, 2019, our oil production was sold based on prices established in Midland, Texas, and our natural gas production was effectively sold based on prices established at the Waha Hub in West Texas. These basis differentials can positively or negatively impact our oil and natural gas revenues.

For the three and six months ended June 30, 2019 and 2018, our production revenues were derived from the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Oil sales	99 %	94%	97%	94%
Natural gas sales	(1)%	1%	—%	2%
Natural gas liquids sales	2 %	5%	3%	4%
Total (1)	100 %	100%	100%	100%

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

The daily spot prices from published sources for Midland–WTI and for natural gas prices at the Waha Hub fluctuated compared to the corresponding NYMEX prices, as seen in the table below for the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Crude Oil (per Bbl):				
Low NYMEX–WTI price	$ 51.13	$ 62.03	$ 46.31	$ 59.20
High NYMEX–WTI price	$ 66.24	$ 77.41	$ 66.24	$ 77.41
Low Midland–WTI price	$ 50.29	$ 55.23	$ 41.09	$ 55.23
High Midland–WTI price	$ 62.65	$ 66.74	$ 62.65	$ 66.91
Natural Gas (per Mcf):				
Low NYMEX–Henry Hub price	$ 2.27	$ 2.74	$ 2.27	$ 2.49
High NYMEX–Henry Hub price	$ 2.76	$ 3.08	$ 4.25	$ 6.24
Low Waha Hub price	$ (4.63)	$ 1.34	$ (4.63)	$ 1.34
High Waha Hub price	$ 1.24	$ 2.60	$ 3.27	$ 7.27

The widening oil and natural gas basis differentials during the three and six months ended June 30, 2019 compared to the same periods in 2018 are largely attributable to the lack of sufficient pipeline takeaway capacity for oil and natural gas production in the Delaware Basin, primarily resulting from increased oil and associated gas production in the area ahead of new pipelines commencing service. Additionally, the Waha Hub experienced a number of outages and maintenance projects impacting major pipelines in the area.

While we were adversely impacted by negative Waha prices during the second quarter of 2019, we continued to produce our wells in order to sell oil, to meet lease and regulatory requirements and to sell the NGLs derived from processing the associated gas production. In addition to the low or negative price at the Waha Hub, the price we receive for our residue gas is affected by certain location, quality and other factors, as well as gathering and processing costs, as stipulated in our marketing agreements with purchasers.

The following table presents our average realized commodity prices, the effects of derivative settlements on our realized prices, the average daily NYMEX spot prices from published sources for oil and natural gas index prices, the average Midland–WTI oil index price and the average WAHA natural gas index price, for the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Crude Oil (per Bbl):				
Average realized price	$ 54.98	$ 60.66	$ 51.96	$ 60.99
Average realized price, including derivative settlements	$ 51.70	$ 55.82	$ 49.81	$ 54.79
Average NYMEX–WTI price	$ 59.88	$ 68.07	$ 57.39	$ 65.55
Average Midland–WTI price	$ 57.72	$ 59.97	$ 55.74	$ 61.21
Natural Gas (per Mcf):				
Average realized price	$ (0.87)	$ 1.05	$ 0.04	$ 1.34
Average NYMEX–Henry Hub price	$ 2.57	$ 2.85	$ 2.74	$ 2.96
Average Waha Hub price	$ 0.01	$ 1.98	$ 0.69	$ 2.21
NGLs (per Bbl):				
Average realized price	$ 7.15	$ 23.36	$ 8.28	$ 22.86

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

Derivative Activity

To reduce the volatility of commodity prices, we enter into derivative instrument contracts which provide increased certainty of cash flows for funding our drilling program and debt service requirements.

As of June 30, 2019, and through the date of this filing, we entered into the following derivative contracts:

Contract Period	Volumes (MBbls)	Wtd Avg Price ($/Bbl)
Oil Swaps (entered into as of June 30, 2019): [1]		
July 01, 2019 through December 31, 2020	7,890	$ 60.28
Oil Basis Swaps (entered into as of June 30, 2019): [2]		
July 01, 2019 through December 31, 2020	14,116	$ (2.28)
Oil Swaps (entered into subsequent to June 30, 2019): [1]		
January 01, 2020 through December 31, 2020	2,196	$ 55.37

(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.

During the six months ended June 30, 2019, we incurred net payments of $11.2 million related to derivative agreements that settled during this time. We do not currently hedge price risk on any of our natural gas or NGL production, but, in the future, we may seek to hedge such production. See Note 3, *Derivative Instruments*, in “Part I. Financial Information - Item 1. Financial Statements” and “Item 3—Quantitative and Qualitative Disclosure About Market Risk—Commodity Price Risk” for information regarding our derivative instruments, exposure to market risk and the effects of changes in commodity prices.

Results of Operations

Comparison of the three months ended June 30, 2019 versus June 30, 2018

Revenues

Oil and Natural Gas Revenues. The following table provides the components of our revenues for the three months ended June 30, 2019 and 2018, as well as each period’s respective average realized prices and production volumes:

(in thousands or as indicated)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Change	% Change
Production revenues:				
Oil sales	$ 145,624	$ 148,614	$ (2,990)	(2)%
Natural gas sales	(2,041)	2,338	(4,379)	(187)%
NGL sales	3,174	7,599	(4,425)	(58)%
Total production revenues	$ 146,757	$ 158,551	$ (11,794)	(7)%
Average realized price: (1)				
Oil (per Bbl)	$ 54.98	$ 60.66	$ (5.68)	(9)%
Natural gas (per Mcf)	$ (0.87)	$ 1.05	$ (1.92)	(183)%
NGLs (per Bbl)	$ 7.15	$ 23.36	$ (16.21)	(69)%
Total (per Boe)	$ 42.15	$ 50.41	$ (8.26)	(16)%
Production volumes:				
Oil (MBbls)	2,649	2,450	199	8 %
Natural gas (MMcf)	2,334	2,220	114	5 %
NGLs (MBbls)	444	325	119	37 %
Total (MBoe)	3,482	3,145	337	11 %
Average daily production volume:				
Oil (Bbls/d)	29,106	26,921	2,185	8 %
Natural gas (Mcf/d)	25,644	24,399	1,245	5 %
NGLs (Bbls/d)	4,879	3,575	1,304	36 %
Total (Boe/d)	38,259	34,562	3,697	11 %

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

As reflected in the table above, our total production revenue for the three months ended June 30, 2019 was 7%, or $11.8 million, lower than that of the same period from 2018. The decrease is primarily due to lower realized commodity prices, partially offset by higher sales volumes during the three months ended June 30, 2019. Our aggregate production volumes in the three months ended June 30, 2019 were 3,482 MBoe, comprised of 76% oil, 11% natural gas and 13% NGLs. This represents an increase of 11% over aggregate production volumes of 3,145 MBoe during the three months ended June 30, 2018.

The following table reconciles the change in oil, natural gas and NGL sales by reflecting the effect of changes in volumes and in the underlying commodity prices, from the three months ended June 30, 2018 to the three months ended June 30, 2019:

(in thousands)	Oil sales (1)	Natural gas sales (1)	NGL sales (1)	Total (1)
Three months ended June 30, 2018	$ 148,614	$ 2,338	$ 7,599	$ 158,551
Changes due to:				
Increase (decrease) in production volumes	12,054	101	2,772	14,927
Increase (decrease) in average realized prices (2)	(15,044)	(4,480)	(7,197)	(26,721)
Three months ended June 30, 2019	$ 145,624	$ (2,041)	$ 3,174	$ 146,757

(1) The net dollar effect of the increases in production is calculated as the change in period-to-period volumes for oil, natural gas and NGLs multiplied by the prior period average prices. The net dollar effect of the changes in prices is calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas and NGLs.

(2) Natural gas and NGL revenues include gathering and processing costs. For the three months ended June 30, 2019 and 2018, these costs reduced our natural gas revenues by $1.2 million and $1.0 million, respectively, and reduced our NGL prices by $4.3 million and $3.0 million, respectively.

Operating Expenses

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

	Three Months Ended June 30,				Per Boe	
(in thousands, except per Boe)	2019	2018	Change	% Change	2019	2018
Lease operating expenses	$ 15,554	$ 10,486	$ 5,068	48 %	$ 4.47	$ 3.33
Production and ad valorem taxes	11,535	9,246	2,289	25 %	$ 3.31	$ 2.94
Exploration	—	1	(1)	(100)%	$ —	$ —
Depletion, depreciation, amortization and accretion	61,222	54,915	6,307	11 %	$ 17.58	$ 17.46
Impairment of unproved oil and natural gas properties	862	—	862	NM	NM	NM
Other operating expenses	6	24	(18)	(75)%	$ —	$ 0.01
General and administrative (before equity-based compensation)	9,085	8,454	631	7 %	$ 2.61	$ 2.69
Total operating expenses (before equity-based compensation)	98,264	83,126	15,138	18 %	$ 28.22	$ 26.43
Equity-based compensation	3,993	2,379	1,614			
Total operating expenses	$ 102,257	$ 85,505	$ 16,752			

NM A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200. A per Boe calculation is not meaningful as the underlying expense does not correspond to changes in production.

Lease Operating Expenses. Lease operating expense (“LOE”) increased to $15.6 million in the three months ended June 30, 2019, compared to $10.5 million for the same period of 2018. The increase largely corresponds to our increased production and well counts between periods, resulting in overall higher costs for contract labor, equipment, electricity and chemicals. Additionally, during the three months ended June 30, 2019, we incurred approximately $2.4 million of additional workover expense as compared to the same period of 2018. LOE per Boe increased 34% to $4.47 for the three months ended June 30, 2019, as compared to the same period of 2018, primarily due to increased costs for workovers, contract labor and equipment.

Production and Ad Valorem Taxes. Production and ad valorem taxes were $11.5 million for the three months ended June 30, 2019, an increase of $2.3 million, or 25%, from $9.2 million for the three months ended June 30, 2018. The increase is due to increased ad valorem taxes which resulted from the addition of multiple new high-volume wells. This was partially offset by a decrease in production taxes that resulted from the decrease in revenues.

Depletion, Depreciation, Amortization and Accretion. The components of depletion, depreciation, amortization and accretion ("DD&A") expense for the three months ended June 30, 2019 and 2018 are summarized as follows:

	Three Months Ended June 30,		Per Boe	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Depletion of oil and natural gas properties	$ 60,748	$ 54,395	$ 17.45	$ 17.29
Depreciation of other property and equipment	424	489	$ 0.12	$ 0.16
Accretion of asset retirement obligations	50	31	$ 0.01	$ 0.01
Depletion, depreciation, amortization and accretion	$ 61,222	$ 54,915	$ 17.58	$ 17.46

Depletion of oil and natural gas properties increased $6.4 million during the three months ended June 30, 2019 compared to the same period of 2018 due to higher production and a slight increase in our depletion rate. Our depletion rate can vary due to changes in proved reserve volumes, acquisition and disposition activity, development costs and impairments. The depletion rate per Boe increased 1% to $17.45 per Boe during the three months ended June 30, 2019, compared to $17.29 per Boe for the three months ended June 30, 2018. The increase in our depletion rate per Boe was largely due to an increase in capitalized costs, while the rate of increase in reserve volumes related to those drilling activities was lower than the rate of capital cost increase.

General and Administrative and Equity-based Compensation. General and administrative expenses ("G&A"), excluding equity-based compensation, increased 7% to $9.1 million for the three months ended June 30, 2019, from $8.5 million for the same period of 2018. The increase is largely due to increased costs related to salaries, employee benefits and contract personnel. The number of full-time employees increased from 75 at June 30, 2018 to 101 at June 30, 2019.

Equity-based compensation expense for the three months ended June 30, 2019 and 2018 is summarized as follows:

	Three Months Ended June 30,		
(in thousands)	**2019**	**2018**	**Change**
Incentive unit awards	$ 548	$ 559	$ (11)
Restricted stock unit awards	1,820	928	892
Performance stock unit awards	1,625	892	733
Equity-based compensation expense	$ 3,993	$ 2,379	$ 1,614

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 June 30,		
(in thousands)	**2019**	**2018**	**Change**
Gain (loss) on commodity derivatives	$ 18,469	$ (9,584)	$ 28,053
Interest expense, net	(9,263)	(6,108)	(3,155)
Other, net	(137)	10	(147)
Total other income (expense)	$ 9,069	$ (15,682)	$ 24,751

Gain (loss) on Commodity Derivatives. We utilize commodity derivative instruments to reduce our exposure to fluctuations in commodity prices. This amount includes (i) the gain (loss) related to derivative contracts that have settled within the period and (ii) the gain (loss) related to fair value adjustments on our open derivative contracts. The following table sets forth these components for the three months ended June 30, 2019 and 2018:

	Three Months Ended June 30,	
(in thousands)	**2019**	**2018**
Net gain (loss) on settled derivative instruments	$ (8,697)	$ (11,879)
Net gain (loss) from the change in fair value of open derivative instruments	27,166	2,295
Gain (loss) on commodity derivatives	$ 18,469	$ (9,584)

Net gains and losses on our derivative instruments are a function of fluctuations in the fair value of our derivatives portfolio between periods and the related cash settlements, if any, of those derivative 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. 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 Expense, net. The following table summarizes our interest expense for the three months ended June 30, 2019 and 2018:

	Three Months Ended June 30,	
(in thousands)	2019	2018
Amended and Restated Credit Facility [1]	$ 1,567	$ 1,615
Senior Notes	7,344	4,346
Amortization of debt issuance costs [2]	590	421
Capitalized interest	(238)	(274)
Interest expense, net	$ 9,263	$ 6,108

(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 Senior Notes is due to a full quarter of expense in 2019 compared to a partial quarter of expense in 2018, as the Senior Notes were issued in May 2018.

Comparison of the six months ended June 30, 2019 versus June 30, 2018

Revenues

Oil and Natural Gas Revenues. The following table provides the components of our revenues for the six months ended June 30, 2019 and 2018, as well as each period’s respective average realized prices and production volumes:

	Six Months Ended June 30,			
(in thousands or as indicated)	2019	2018	Change	% Change
Production revenues:				
Oil sales	$ 269,114	$ 269,337	$ (223)	— %
Natural gas sales	177	5,213	(5,036)	(97)%
NGL sales	7,052	12,907	(5,855)	(45)%
Total production revenues	$ 276,343	$ 287,457	$ (11,114)	(4)%
Average realized price: [1]				
Oil (per Bbl)	$ 51.96	$ 60.99	$ (9.03)	(15)%
Natural gas (per Mcf)	$ 0.04	$ 1.34	$ (1.30)	(97)%
NGLs (per Bbl)	$ 8.28	$ 22.86	$ (14.58)	(64)%
Total (per Boe)	$ 40.75	$ 51.07	$ (10.32)	(20)%
Production volumes:				
Oil (MBbls)	5,179	4,416	763	17 %
Natural gas (MMcf)	4,503	3,886	617	16 %
NGLs (MBbls)	851	565	286	51 %
Total (MBoe)	6,781	5,629	1,152	20 %
Average daily production volume:				
Oil (Bbls/d)	28,612	24,400	4,212	17 %
Natural gas (Mcf/d)	24,878	21,471	3,407	16 %
NGLs (Bbls/d)	4,703	3,120	1,583	51 %
Total (Boe/d)	37,462	31,098	6,364	20 %

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

As reflected in the table above, our total production revenue for the six months ended June 30, 2019 was 4%, or $11.1 million, lower than that of the same period from 2018. The decrease is primarily due to lower realized commodity prices, offset by higher sales volumes, during the six months ended June 30, 2019. Our aggregate production volumes in the six months ended

June 30, 2019 were 6,781 MBoe, comprised of 76% oil, 11% natural gas and 13% NGLs. This represents an increase of 20% over aggregate production volumes of 5,629 MBoe during the six months ended June 30, 2018.

The following table reconciles the change in oil, natural gas and NGL sales by reflecting the effect of changes in volumes and in the underlying commodity prices, from the six months ended June 30, 2018 to the six months ended June 30, 2019:

(in thousands)	Oil sales (1)	Natural gas sales (1)	NGL sales (1)	Total (1)
Six months ended June 30, 2018	$ 269,337	$ 5,213	$ 12,907	$ 287,457
Changes due to:				
Increase (decrease) in production volumes	46,542	818	6,557	53,917
Increase (decrease) in average realized prices (2)	(46,765)	(5,854)	(12,412)	(65,031)
Six months ended June 30, 2019	$ 269,114	$ 177	$ 7,052	$ 276,343

(1) The net dollar effect of the increases in production is calculated as the change in period-to-period volumes for oil, natural gas and NGLs multiplied by the prior period average prices. The net dollar effect of the changes in prices is calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas and NGLs.

(2) Natural gas and NGL revenues include gathering and processing costs. For the six months ended June 30, 2019 and 2018, these costs reduced our natural gas revenues by $2.2 million and $1.9 million, respectively, and reduced our NGL revenues by $7.5 million and $4.6 million, respectively.

Operating Expenses

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

	Six Months Ended June 30,				Per Boe	
(in thousands, except per Boe)	2019	2018	Change	% Change	2019	2018
Lease operating expenses	$ 29,204	$ 20,206	$ 8,998	45 %	$ 4.31	$ 3.59
Production and ad valorem taxes	20,837	16,920	3,917	23 %	$ 3.07	$ 3.01
Exploration	—	1	(1)	(100)%	$ —	$ —
Depletion, depreciation, amortization and accretion	120,296	102,892	17,404	17 %	$ 17.74	$ 18.28
Impairment of unproved oil and natural gas properties	946	53	893	NM	NM	NM
Other operating expenses	3,206	46	3,160	NM	$ 0.47	$ 0.01
General and administrative (before equity-based compensation)	19,545	19,093	452	2 %	$ 2.88	$ 3.39
Total operating expenses (before equity-based compensation)	194,034	159,211	34,823	22 %	$ 28.61	$ 28.28
Equity-based compensation	6,927	78,057	(71,130)			
Total operating expenses	$ 200,961	$ 237,268	$ (36,307)			

NM A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200. A per Boe calculation is not meaningful as the underlying expense does not correspond to changes in production.

Lease Operating Expenses. LOE increased to $29.2 million in the six months ended June 30, 2019, compared to $20.2 million for the same period of 2018. The increase largely corresponds to our increased production and well counts between periods, resulting in overall higher costs for equipment and equipment rental, contract labor and electricity. Additionally, during the six months ended June 30, 2019, we incurred approximately $3.3 million of additional workover expense as compared to the same period of 2018. LOE per Boe increased $0.72 to $4.31 for the six months ended June 30, 2019, as compared to the same period of 2018, primarily due to increased costs on workovers, equipment and equipment rentals and electricity on operated wells, and increased costs on nonoperated wells.

Production and Ad Valorem Taxes. Production and ad valorem taxes were $20.8 million for the six months ended June 30, 2019, an increase of $3.9 million, or 23%, from $16.9 million for the six months ended June 30, 2018. The increase was due to increased ad valorem taxes from the addition of multiple new high-volume wells, partially offset by a slight decrease in production taxes due to a decrease in revenues.

Depletion, Depreciation, Amortization and Accretion. The components of DD&A expense for the six months ended June 30, 2019 and 2018 are summarized as follows:

	Six Months Ended June 30,		Per Boe	
(in thousands)	2019	2018	2019	2018
Depletion of oil and natural gas properties	$ 119,359	$ 101,805	$ 17.60	$ 18.09
Depreciation of other property and equipment	841	1,031	$ 0.12	$ 0.18
Accretion of asset retirement obligations	96	56	$ 0.02	$ 0.01
Depletion, depreciation, amortization and accretion	$ 120,296	$ 102,892	$ 17.74	$ 18.28

Depletion of oil and natural gas properties increased $17.6 million during the six months ended June 30, 2019 compared to the same period of 2018 primarily due to higher production, partially offset by a decrease in our depletion rate. Our depletion rate can vary due to changes in proved reserve volumes, acquisition and disposition activity, development costs and impairments. The depletion rate per Boe decreased $0.49 to $17.60 per Boe during the six months ended June 30, 2019, compared to $18.09 per Boe for the six months ended June 30, 2018. The decrease in our depletion rate was largely due to an increase in reserve volumes due to continued successful drilling activities, whereas the rate of increase in capitalized costs related to those drilling activities was lower than the rate of reserve increase.

Other Operating Expenses. The $3.2 million of other operating expenses for the six months ended June 30, 2019 was related to the early termination of a frac fleet contract in the first quarter of 2019.

General and Administrative and Equity-based Compensation. G&A, excluding equity-based compensation, increased 2% to $19.5 million for the six months ended June 30, 2019, from $19.1 million for the same period of 2018. The slight increase is primarily due to increased personnel costs, including salaries, employee benefits and contract personnel. These increases were partially offset by a $2.8 million decrease related to severance and other nonrecurring expenses from the first quarter of 2018. The number of full-time employees increased from 75 at June 30, 2018 to 101 at June 30, 2019.

Equity-based compensation expense for the six months ended June 30, 2019 and 2018 is summarized as follows:

	Six Months Ended June 30,		
(in thousands)	2019	2018	Change
Incentive unit awards	$ 1,194	$ 75,158	$ (73,964)
Restricted stock unit awards	3,149	2,402	747
Performance stock unit awards	2,584	497	2,087
Equity-based compensation expense	$ 6,927	$ 78,057	$ (71,130)

The decrease in equity-based compensation expense for incentive unit awards is due to a modification of the service requirements in the first quarter of 2018, which resulted in an acceleration of the compensation expense for the awards allocated at the time of the IPO. The remaining incentive unit award expense relates to awards allocated after the IPO.

The increase in equity-based compensation expense for PSU awards is due to the reversal of equity-based compensation expense during the three months ended June 30, 2018, which related to forfeited PSU awards by former executive officers. As the Company's policy is to recognize forfeitures as they occur, previously recognized expense on unvested awards is reversed at the date of forfeiture.

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:

	Six Months Ended June 30,		
(in thousands)	2019	2018	Change
Gain (loss) on commodity derivatives	$ (125,123)	$ (13,910)	$ (111,213)
Interest expense, net	(17,709)	(8,839)	(8,870)
Other, net	(123)	18	(141)
Total other income (expense)	$ (142,955)	$ (22,731)	$ (120,224)

Gain (loss) on Commodity Derivatives. We utilize commodity derivative instruments to reduce our exposure to fluctuations in commodity prices. This amount includes (i) the gain (loss) related to derivative contracts that have settled within the period and (ii) the gain (loss) related to fair value adjustments on our open derivative contracts. The following table sets forth these components for the six months ended June 30, 2019 and 2018:

	Six Months Ended June 30,	
(in thousands)	2019	2018
Net gain (loss) on settled derivative instruments	$ (11,167)	$ (27,358)
Net gain (loss) from the change in fair value of open derivative instruments	(113,956)	13,448
Gain (loss) on commodity derivatives	$ (125,123)	$ (13,910)

Net gains and losses on our derivative instruments are a function of fluctuations in the fair value of our derivatives portfolio between periods and the related cash settlements, if any, of those derivative 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. 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 Expense, net. The following table summarizes our interest expense for the six months ended June 30, 2019 and 2018:

	Six Months Ended June 30,	
(in thousands)	2019	2018
Amended and Restated Credit Facility (1)	$ 2,317	$ 4,037
Senior Notes	14,688	4,346
Amortization of debt issuance costs (2)	1,176	1,021
Capitalized interest	(472)	(565)
Interest expense, net	$ 17,709	$ 8,839

(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 total interest expense during the six months ended June 30, 2019 is associated with the issuance of the Senior Notes in May 2018.

Income tax expense (benefit)

During the six months ended June 30, 2019, we had an income tax benefit of $14.6 million, compared to an expense of $22.1 million for the same period of 2018. The change is primarily due to a net loss in the first six months of 2019 compared to net income in the first six months of 2018. Income tax expense in the first six months of 2018 primarily resulted from equity-based compensation expense related to incentive unit awards that were allocated at the time of the IPO, which was not deductible for federal or state income tax purposes.

Capital Commitments, Capital Resources and Liquidity

Capital Commitments

Our primary needs for cash relate to the development and exploration of our oil and natural gas assets, payment of contractual obligations and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, borrowings under our Amended and Restated Credit Facility, joint venture partnerships, production payment financings, asset sales, offerings of debt and equity securities or other means.

2019 Capital Budget

Our 2019 capital budget for development of oil and gas properties and infrastructure is as follows:

(in millions)			
Drilling and completion	$ 580.0	—	$ 630.0
Water infrastructure	25.0	—	35.0
Total	$ 605.0	—	$ 665.0

Our 2019 capital budget excludes potential leasehold and/or surface acreage additions. 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 or reallocate priorities in 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 if such changes in 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 planned 2019 capital program. 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 Amended and Restated 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 planned drilling program. In addition, 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.

Capital Expenditures

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Acquisitions				
Proved properties	$ 584	$ —	$ 7,407	$ —
Unproved properties (1)	2,601	3,771	7,978	11,095
Development costs	151,960	176,178	288,690	383,793
Infrastructure costs	15,523	4,065	21,158	8,001
Exploration costs	—	1	—	1
Total oil and gas capital expenditures	$ 170,668	$ 184,015	$ 325,233	$ 402,890

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

For the six months ended June 30, 2019 and 2018, our capital expenditures have been focused on the development of our properties in the southern Delaware Basin, as seen in the table below showing newly producing wells. As of June 30, 2019, we had approximately 88,200 gross (78,100 net) acres.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	**2018**	**2019**	**2018**
Gross wells				
Operated	11	15	23	26
Non-operated	—	4	—	12
	11	19	23	38
Net wells				
Operated	10.4	13.7	22.2	23.7
Non-operated	—	1.6	—	5.0
	10.4	15.3	22.2	28.7

At June 30, 2019, we were in the process of drilling seven gross (6.7 net) wells and had ten gross (9.5 net) wells waiting on completion, including six gross (5.6 net) wells that were in process of being completed.

Contractual Obligations

A summary of our contractual obligations as of June 30, 2019 is provided in the following table:

(in thousands)	Remainder of 2019	Payments Due by Period for the Year Ending December 31, 2020	2021	2022	2023	Thereafter	Total
Senior secured credit facility (1)	$ —	$ —	$ —	$ —	$ 150,000	$ —	$ 150,000
Senior notes—principal	—	—	—	—	—	500,000	500,000
Senior notes—interest (2)	14,688	29,375	29,375	29,375	29,375	73,437	205,625
Operating leases (3)	18,900	33,428	1,547	1,558	1,589	7,378	64,400
Service and purchase contracts (4)	9,690	6,878	3,706	3,633	3,633	13,926	41,466
Rig contracts (5)	748	—	—	—	—	—	748
Total	$ 44,026	$ 69,681	$ 34,628	$ 34,566	$ 184,597	$ 594,741	$ 962,239

(1) This table does not include future commitment fees, interest expense or other costs related to our credit facility because we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged. As of June 30, 2019, we had $150.0 million outstanding under our Amended and Restated Credit Facility. The borrowing base and elected commitments remained at $900.0 million and $540.0 million, respectively, and the Company had $390.0 million of elected commitments available.
(2) Interest represents the scheduled cash payments on the Senior Notes.
(3) Relates to lease payment maturities for our operating leases, which include drilling rigs, our corporate headquarters and certain office equipment. See Note 10, *Leases*, in "Part I. Financial Information - Item 1. Financial Statements" for more information on our operating leases.
(4) Primarily relates to a coiled tubing service agreement and a retail power purchase agreement.
(5) Relates to a short-term operating lease for one drilling rig under contract at June 30, 2019.

Additionally, in 2018 the Company entered into a 5-year oil marketing agreement that is expected to take effect at the commencement of commercial operations on the Cactus II pipeline and will link a portion of the Company's oil production to Gulf Coast pricing. This agreement specifies a minimum gross volume commitment of 30,000 barrels of oil per day. If the Company is not able to provide the contractual quantity to the buyer, it would be subject to a deficiency payment relative to a price difference on the deficient volume. Based on its current and projected production levels, the Company does not believe a deficiency payment will be required under this agreement.

Off-Balance Sheet Arrangements

We had no material off balance sheet arrangements as of June 30, 2019. Please read Note 11, *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.

Capital Resources and Liquidity

Historically, our primary capital resources and liquidity were capital contributions from equity owners, including the IPO, proceeds from the Senior Notes offering, borrowings under our credit facility and cash flows from operations. During the first six months of 2019, our primary sources of liquidity were borrowings on our credit facility of $150.0 million and cash flows from operations of $168.2 million. Our primary uses of cash have been the development and acquisition of oil and natural gas properties and the development of water sourcing and disposal infrastructure. 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.

Based on our forecasted cash flows from operating activities and availability under our revolving credit facilities, we expect to be able to fund our planned capital expenditures, meet our debt service requirements and fund our other commitments and obligations for the next 12 months.

Cash Flows

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

	Six Months Ended June 30,	
(in thousands)	2019	2018
Net cash provided by operating activities	$ 168,247	$ 199,814
Net cash used in investing activities	$ (327,884)	$ (405,902)
Net cash provided by financing activities	$ 149,204	$ 332,057

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

The $31.6 million decrease in the first six months of 2019 compared to 2018 primarily resulted from lower realized commodity prices. We also experienced higher cash operating costs and general and administrative 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 six months of 2019, net cash flow used in investing activities was $327.9 million, which included investments in developing our acreage of $311.9 million and leasehold and acquisition costs of $15.6 million. In the first six months of 2018, net cash used for investing activities of $405.9 million included $393.0 million and $11.1 million for the development and acquisition of oil and natural gas properties, respectively.

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

Net cash provided by financing activities during the first six months of 2019 was primarily due to $150.0 million of borrowings on our credit facility. Net cash provided by financing activities in the first six months of 2018 was primarily due to $488.7 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.

Senior Secured Revolving Credit Facility

At December 31, 2018, the Amended and Restated Credit Facility had a borrowing base of $900.0 million, with nothing outstanding under the credit facility, and $540.0 million in unused borrowing capacity under our elected commitments. At June 30, 2019, the borrowing base and elected commitments remained at $900.0 million and $540.0 million, respectively, and we had $150.0 million outstanding and $390.0 million of elected commitments available. As of the date of this filing, the Company has $190.0 million outstanding and $350.0 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 each 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 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 June 30, 2019, we were in compliance with all financial covenants.

Please read Note 4, *Debt*, in “Part I. Financial Information - Item 1. Financial Statements” for more information on our Amended and Restated Credit Facility.

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 2018 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 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 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 2018 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 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 historically been volatile and unpredictable, 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 six months ended June 30, 2019:

			Sensitivity Analysis	
(in thousands)	Revenue(1)	% of Total	Change in Realized Prices	Impact on Revenue
Oil	$ 269,114	97%	+ / - 10% per barrel	+ / - $ 26,911
Natural gas	177	—%	+ / - 10% per Mcf	+ / - $ 18
NGL	7,052	3%	+ / - 10% per barrel	+ / - $ 705
Total	$ 276,343	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 2019 and 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 the contracted period of time. Our commodity derivative instruments are recorded at fair value and the changes to future commodity prices has an impact on net income. During the six months ended June 30, 2019 we recorded a loss on derivatives of $125.1 million, compared to a loss of $13.9 million for the same period in 2018.

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 six months ended June 30, 2019.

The following table reconciles the changes that occurred in the fair values of our derivative instruments from December 31, 2018 to June 30, 2019:

(in thousands)		Commodity Derivative Instruments Net Assets (Liabilities)
Fair value of open contracts at December 31, 2018	$	100,621
Gain (loss) on commodity derivatives		(125,123)
Net cash payments on settled derivatives		11,167
Fair value of open contracts at June 30, 2019	$	(13,335)

The following table sets forth the hypothetical impact on the fair value of our net oil derivative liability of $13.3 million as of June 30, 2019, using an average increase or decrease of 10% to the commodity prices:

	Change in Forward Commodity Prices			
(in thousands)		10% Increase		10% Decrease
Increase (decrease) to net oil derivative liability as of June 30, 2019	$	45,192	$	(45,192)

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, or affiliates of lenders, under 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 June 30, 2019, we had no significant investments; therefore, we were not exposed to material interest rate risk on investments.

As of June 30, 2019, we had approximately $639.9 million of long-term debt outstanding, net of unamortized debt issuance costs. Of this amount, $489.9 million was fixed-rate debt, net of unamortized debt issuance costs, with a fixed interest coupon 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.

The $150.0 million outstanding under our Amended and Restated Credit Facility as of June 30, 2019 is subject to variable interest rates, which expose us to the risk of earnings or cash flow loss due to potential increases in market interest rates. A change in the interest rate applicable to our variable-rate debt could expose us to additional interest cost. Assuming no change in the amount outstanding, the impact on interest expense of a 1% increase or decrease in the assumed weighted average interest rate would be approximately $1.5 million per year.

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 June 30, 2019. 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 June 30, 2019 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. 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, 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, 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

The following table summarizes the repurchase of our common stock during the three months ended June 30, 2019:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet be Purchased Under the Plans or Programs
April 1, 2019 - April 30, 2019	31,928	$ 10.98	—	—
May 1, 2019 - May 31, 2019	436	$ 10.35	—	—
June 1, 2019 - June 30, 2019	2,642	$ 7.87	—	—
Total	35,006	$ 9.61	—	—

(1) Shares purchased represent shares of our common stock transferred to us to satisfy tax withholding obligations incurred upon the vesting of certain equity awards held by our employees.

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. 6 to Amended and Restated Credit Agreement, dated as of April 29, 2019, 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 (incorporated by reference to Exhibit 10.1 to the Company's Form 10-Q filed with the SEC on May 9, 2019).
*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	Inline XBRL Instance Document - The instance document does not appear in the interactive data file because its XBRL tags are embedded within the Inline XBRL document.
*101.SCH	Inline XBRL Schema Document
*101.CAL	Inline XBRL Calculation Linkbase Document
*101.LAB	Inline XBRL Label Linkbase Document
*101.PRE	Inline XBRL Presentation Linkbase Document
*101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document

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* 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:	August 8, 2019	By:	/s/ JAMES J. KLECKNER	
			Name:	James J. Kleckner
			Title:	*Chief Executive Officer and President*
Date:	August 8, 2019	By:	/s/ ROBERT W. HOWARD	
			Name:	Robert W. Howard
			Title:	*Executive Vice President, Chief Financial Officer*
Date:	August 8, 2019	By:	/s/ SHONN D. STAHLECKER	
			Name:	Shonn D. Stahlecker
			Title:	*Controller*

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: August 8, 2019

/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: August 8, 2019

/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 June 30, 2019, 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:	August 8, 2019	/s/ JAMES J. KLECKNER	
		Name:	James J. Kleckner
		Title:	Chief Executive Officer and President

Certification

In connection with the Quarterly Report of Jagged Peak Energy Inc. (the “Company”) on Form 10-Q for the quarter ended June 30, 2019, 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:	August 8, 2019	/s/ ROBERT W. HOWARD	
		Name:	Robert W. Howard
		Title:	Executive Vice President and Chief Financial Officer