Falcon Minerals

Annual Report to Shareholders

For the Year Ended December 31, 2019

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2019

or

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

For the transition period from ________ to ________

Commission file number: 001-38158

FALCON MINERALS CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

Delaware **(State or Other Jurisdiction of Incorporation or Organization)**	**82-0820780** **(I.R.S. Employer Identification No.)**
510 Madison Avenue, 8th Floor, New York, NY **(Address of Principal Executive Offices)**	**10022** **(Zip Code)**

Registrant's telephone number, including area code: (212) 506-5925

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Class A Common Stock, par value $0.0001 per share	FLMN	Nasdaq Capital Market
Warrants, each to purchase one share of Class A Common Stock	FLMNW	Nasdaq Capital Market

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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 Act). Yes ☐ No ☑

As of June 28, 2019, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of the registrant's voting securities held by non-affiliates was approximately $342.3 million, based on the number of shares held by non-affiliates and the last reported sales price of the registrant's Class A common stock as of that date.

As of March 6, 2020, there were 45,963,716 shares of the registrant's Class A common stock, par value $0.0001 per share, issued and outstanding and there were 40,000,000 shares of the registrant's Class C common stock, par value of $0.0001 per share, issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: Portions of the proxy statement for registrant's 2020 Annual Meeting of Stockholders are incorporated by reference in Part III in this Form 10-K.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this Annual Report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact, 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 Annual Report, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project," and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed in this Annual Report, including those detailed under "Item 1A. Risk Factors" in this Annual Report, could affect our actual results and cause our actual results to differ materially from expectations, estimates or assumptions expressed, forecasted or implied in such forward-looking statements.

Forward-looking statements may include statements about:

- our ability to execute our business strategies;
- the volatility of realized oil and natural gas prices;
- the level of production on our properties;
- regional supply and demand factors, delays or interruptions of production;
- our ability to replace our oil and natural gas reserves;
- our ability to identify, complete and integrate acquisitions of properties or businesses;
- general economic, business or industry conditions;
- competition in the oil and natural gas industry;
- the ability of our operators to obtain capital or financing needed for development and exploration operations;
- title defects in the properties in which we invest;
- uncertainties with respect to identified drilling locations and estimates of reserves;
- the availability or cost of rigs, equipment, raw materials, supplies, oilfield services or personnel;
- restrictions on the use of water;
- the availability of transportation facilities;
- the ability of our operators to comply with applicable governmental laws and regulations and to obtain permits and governmental approvals;
- federal and state legislative and regulatory initiatives relating to hydraulic fracturing;
- future operating results;
- exploration and development drilling prospects, inventories, projects and programs;
- operating hazards faced by our operators; and
- the ability of our operators to keep pace with technological advancements.

The forward-looking statements contained in this Annual Report are based on our current expectations and beliefs concerning future developments and their potential effects on us. There can be no assurance that future developments affecting us will be those that we have anticipated. These forward-looking statements involve a number of risks, uncertainties (some of which are beyond our control) or other assumptions that may cause actual results or performance to be materially different from those expressed or implied by these forward-looking statements. These risks and uncertainties include, but are not limited to, those factors described under the heading "Risk Factors". Should one or more of these risks or uncertainties materialize, or should any of our assumptions prove incorrect, actual results may vary in material respects from those projected in these forward-looking statements. We undertake no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required under applicable securities laws.

GLOSSARY OF TERMS

Adjusted EBITDA: Represents net income before interest expense, income taxes and depreciation and amortization expense, as further adjusted for other non-cash charges and other charges that are not reflective of our ongoing operations. Adjusted EBITDA is not a presentation made in accordance with GAAP. Please see the reconciliation of Adjusted EBITDA to net income in Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview of Our Results of Operations—Adjusted EBITDA."

Barrel or ***bbl***: Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.

BOE: Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

BOE/d: BOE per day.

British Thermal Unit or Btu: The quantity of heat required to raise the temperature of one pound of water by one-degree Fahrenheit.

Completion: The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate: Liquid hydrocarbons associated with the production that is primarily natural gas.

Crude oil: Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.

Developed acreage: Acreage allocated or assignable to productive wells.

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

GAAP: Generally accepted accounting principles in the United States.

Gross acres or gross wells: The total acres or wells, as the case may be, in which an overriding, royalty or mineral interest is owned.

MBbls: Thousand barrels of crude oil or other liquid hydrocarbons.

MBOE: One thousand barrels of crude oil equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Mcf: Thousand cubic feet of natural gas.

Mineral interests: The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.

MMBtu: Million British Thermal Units.

MMcf: Million cubic feet of natural gas.

Net royalty acres: Gross acreage multiplied by the average royalty interest.

NGLs: Natural gas liquids.

Prospect: A specific geographic area which, based on supporting geological, geophysical or other data and preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved reserves: The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

PUD: Proved undeveloped, used to characterize reserves.

Reserves: The estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to the market and all permits and financing required to implement the project. Reserves are not assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Reservoir: A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Royalty interest: An interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development.

SEC: U.S. Securities and Exchange Commission.

Undeveloped acreage: Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Unless the context clearly indicates otherwise, references in this Annual Report on Form 10-K to "Falcon," the "Company," "we," "our," "us" or similar terms refer to Falcon Minerals Corporation and its subsidiaries.

PART I

ITEM 1.BUSINESS

Corporate History

Falcon (formerly named Osprey Energy Acquisition Corp.) was a blank check company, incorporated in Delaware in June 2016. The Company was formed for the purpose of acquiring, through a merger, capital stock exchange, asset acquisition, stock purchase, reorganization, recapitalization, or other similar business transaction, one or more operating businesses or assets.

On August 23, 2018 (the "Closing Date"), the Company completed the acquisition of the equity interests (the "Equity Interests") in certain of the subsidiaries (the "Royal Entities") of Noble Royalties Acquisition Co., LP ("NRAC"), Hooks Ranch Holdings LP ("Hooks Holdings"), DGK ORRI Holdings, LP ("DGK"), DGK ORRI GP LLC ("DGK GP") and Hooks Holding Company GP, LLC ("Hooks GP", and collectively with NRAC, Hooks Holdings, DGK, and DGK GP, the "Contributors"). The acquisition was made pursuant to the Contribution Agreement, dated as of June 3, 2018 (the "Contribution Agreement"), by and among the Company, Royal Resources L.P. ("Royal"), Royal Resources GP L.L.C. ("Royal GP") and the Contributors. The acquisition of the Royal Entities pursuant to the Contribution Agreement is referred to as the "Business Combination" and the Business Combination together with the other transactions contemplated by the Contribution Agreement are referred to herein as the "Transactions."

Pursuant to the Contribution Agreement, on the Closing Date, the Company contributed cash to Falcon Minerals Operating Partnership, LP, a Delaware limited partnership and wholly owned subsidiary of the Company ("OpCo"), in exchange for (a) a number of OpCo Common Units representing limited partnership interests in OpCo (the "OpCo Common Units") equal to the number of shares of the Company's Class A common stock, par value $0.0001 per share (the "Class A Common Stock"), outstanding as of the Closing Date and (b) a number of OpCo warrants exercisable for OpCo Common Units equal to the number of the Company's warrants outstanding as of the Closing Date. The Company controls OpCo through Falcon Minerals GP, LLC, a Delaware limited liability company, a wholly owned subsidiary of the Company and the sole general partner of OpCo ("Opco GP").

In connection with the Company's entry into the Contribution Agreement, the Company agreed to issue and sell in a private placement an aggregate of 11,480,000 shares of Class A Common Stock for a purchase price of $10.00 per share, and aggregate consideration of $114.8 million (the "Private Placement"). The Private Placement was consummated concurrently with the Transactions on the Closing Date and the proceeds of the Private Placement were used to fund a portion of the cash consideration paid to the Contributors.

On the Closing Date, Falcon completed the acquisition of the Equity Interests and in return the Contributors received (i) $400 million of cash and (ii) 40 million OpCo Common Units. The Company also issued to the Contributors 40 million shares of non-economic Class C common stock of the Company, which entitles each holder to one vote per share. The OpCo Common Units are redeemable on a one-for-one basis for shares of Class A Common Stock at the option of the Contributors. Upon the redemption by any Contributor of OpCo Common Units for Class A Common Stock, a corresponding number of shares of Class C Common Stock held by such Contributor will be cancelled.

In connection with the closing of the Business Combination (the "Closing"), the Company changed its name from "Osprey Energy Acquisition Corp." to "Falcon Minerals Corporation". The Company is now structured as an "Up-C," meaning that substantially all the assets of the Company are held by OpCo, and the Company's only operating asset is its equity interest in OpCo. Each OpCo Common Unit, together with one share of Class C Common Stock, is exchangeable for one share of Class A Common Stock at the option of the holder pursuant to the terms of the Company's and OpCo's organizational documents, subject to certain restrictions.

Presentation of Financial and Operating Data

The acquisition of the Royal Entities has been accounted for as a reverse recapitalization. Under this method of accounting, Falcon will be treated as the acquired company and Royal will be treated as the acquirer for financial reporting purposes. Therefore, the consolidated financial results include information regarding Royal as the Company's predecessor entity, which includes certain interests in subsidiary companies which were not acquired by the Company in the Transactions. Thus, the financial statements included in this Annual Report reflect (i) the historical operating results of Royal prior to the Transactions; (ii) the combined results of the Company, OpCo and Royal following the Transactions; (iii) the assets, liabilities and partners' capital of Royal at their historical costs; and (iv) the Company's equity and earnings per share presented for the period from the Closing Date of the Business Combination. The Royal subsidiaries that were contributed in the Transactions are VickiCristina, LP, DGK ORRI Company, L.P., Noble EF DLG LP, Noble EF LP and Noble Marcellus LP. The interests in Riverbend Natural Resources, L.P. ("RNR") and KGD ORRI, L.P. were not contributed in the Transactions (the "Non-Contributed Entities"). For the years ended December 31, 2018 and 2017, the amounts attributed to RNR interests related to the Transactions are included in discontinued operations in the consolidated statements of operations.

Our Business

We were formed to own and acquire royalty interests, mineral interests, non-participating royalty interest and overriding royalty interests, or ORRIs (collectively, “Royalties”), in oil and natural gas properties in North America, substantially all of which are located in the Eagle Ford Shale. These Royalties entitle the holder to a portion of the production of oil and natural gas from the underlying acreage at the sales price received by the operator, net of any applicable post-production expenses and taxes. The holder of these interests has no obligation to fund exploration and development costs, lease operating expenses or plugging and abandonment costs at the end of a well’s productive life, which we believe results in low breakeven costs.

We own Royalties that entitle us to a portion of the production of oil, natural gas and NGLs from the underlying acreage at the sales price received by the operator, net of marketing and transportation expenses and production taxes. We have no obligation to fund finding and development costs or pay capital expenditures such as plugging and abandonment costs. As such, we have historically operated with high cash margins, converting a large percentage of revenue to free cash flow, the majority of which can be distributed to our shareholders.

As of December 31, 2019, our assets consisted of Royalties underlying approximately 256,000 gross unit acres (approximately 2,670 net royalty acres not normalized to 1/8th) that are concentrated in what we believe is the “core-of-the-core” of the liquids-rich condensate region of the Eagle Ford Shale in Karnes, DeWitt, and Gonzales Counties, Texas. In all three of these counties, we also have substantial exposure to the Austin Chalk and Upper Eagle Ford formations (this overlapping acreage is included in the 256,000 gross unit acres), which have experienced increased horizontal development activity, in addition to the more established and historically developed Lower Eagle Ford formation. We believe that the wells and remaining drilling locations on the properties underlying our assets are among the most economic in North America, with operator break-even oil prices under $35 per barrel. Development activity has historically been supported by positive oil price differentials averaging a positive $2.50 per barrel over the past 12 months. In addition, our assets include Royalties related to approximately 75,000 gross unit acres in the Appalachian region, including Pennsylvania, West Virginia and Ohio. Our acreage was extensively delineated by 2,260 producing wells as of December 31, 2019, of which 1,924 are located in Karnes, DeWitt, and Gonzales Counties, providing extensive subsurface data control and substantial confidence on individual well initial production rates, production profiles and estimated ultimate recoveries (“EURs”). The average net daily production attributable to our net royalty interests was 4,861 BOE/d (50% oil) for the year ended December 31, 2019. This includes Eagle Ford production of 4,141 BOE/d (58% oil).

The Eagle Ford Shale is the second largest oil field in North America and is one of the lowest-cost and most active unconventional shale trends. It has a world-class aerial extent that covers approximately 13 million surface acres and has extensive data control as a result of more than 18,000 producing horizontal wells. The Eagle Ford has top-tier single-well economics, is operated by premier oil and gas companies and has access to abundant offtake infrastructure in close proximity to the U.S. Gulf Coast. In recent years, the entire Eagle Ford Shale play has undergone a technical transformation largely driven by utilization of modern drilling and completion techniques, resulting in improved oil and gas sectional recoveries, enhanced production rates, EURs, well economics and increased activity by operators. Our acreage is located in what we believe is the “core-of-the-core” of the Eagle Ford Shale and is characterized by high oil and liquids content and low finding and development costs as well as positive differentials that drive attractive economics to operators relative to other unconventional basins. We believe these factors make the development of our underlying acreage commercially viable and highly attractive in lower commodity price environments. Approximately 89% of our Eagle Ford and Austin Chalk acreage is operated by ConocoPhillips (“ConocoPhillips”), EOG Resources, Inc. (“EOG”), and BP Plc (“BP”) and Devon Energy Corporation (“Devon”) through a joint venture.

Our revenues are derived from royalty payments we receive from our operators based on the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from natural gas during processing. For the year ended December 31, 2019, our revenues were derived 77% from oil and condensate sales, 14% from natural gas liquid sales and 3% from natural gas sales. For the year ended December 31, 2018, our revenues were derived 81% from oil and condensate sales, 12% from natural gas liquid sales and 7% from natural gas sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. Oil, natural gas and NGL prices have historically been volatile, and at December 31, 2019 we did not hedge any of our exposure to changes in commodity prices.

Our Properties

Our assets consist of Royalties related to 503 drilling units, concentrated in what we believe is the “core of the core” of the Eagle Ford Shale as well as the Marcellus Shale and Point Pleasant formations. As of December 31, 2019, these interests entitled us to receive an average royalty of 1.32% from the producing wells on the acreage underlying our Royalties, with no additional future capital or operating expenses required. As of December 31, 2019, there were 2,260 wells producing on this acreage, and average net production for the year ended December 31, 2019 was approximately 4,861 BOE/d. In addition, there were 122 horizontal wells in various stages of completion. As of December 31, 2019, there were 88 additional permits outstanding for undrilled wells or wells currently being drilled on the acreage underlying our Royalties.

The leases underlying our Royalties were delineated by 2,260 producing wells as of December 31, 2019. We own interests in 503 drilling units in the Eagle Ford Shale, Marcellus Shale, and Point Pleasant formations.

Comparison of Types of Interests

Royalty Interest. Royalty interests generally result when the owner of a mineral interest leases the underlying minerals to a working interest holder pursuant to an oil and gas lease. Typically, the resulting royalty interest is a cost-free percentage of production revenues for minerals extracted from the acreage. Holders of royalty interests are generally not responsible for capital expenditures or lease operating expenses, but may be responsible for certain post-production expenses, and typically have limited environmental liability. Royalty interests expire upon the expiration of the oil and gas lease.

Mineral Interest. Mineral interests are perpetual rights of the owner to exploit, mine, and/or produce any or all of the minerals lying below the surface of the property. The holder of a mineral interest has the right to lease the minerals to a working interest holder pursuant to an oil and gas lease.

Non-Participating Royalty Interest (NPRI). NPRI is an interest in oil and gas production which is created from the mineral estate. The NPRI is expense-free, bearing no operational costs of production. The term "non-participating" indicates that the interest owner does not share in the bonus, rentals from a lease, nor the right to participate in the execution of oil and gas leases.

Working Interest. Working interest holders have the rights to extract minerals from acreage leased pursuant to an oil and gas lease from a mineral interest holder. Holders of working interests are responsible for their pro rata share of capital expenditures and lease operating expenses, but holders of working interests only receive revenues after distributions have first been made to holders of royalty interests and ORRIs. Working interests expire upon the termination or expiration of the underlying oil and gas lease.

Overriding Royalty Interest ("ORRIs"). ORRIs are created by carving out the right to receive royalties from a working interest. Like royalty interests, ORRIs do not confer an obligation to make capital expenditures or pay for lease operating expenses and have limited environmental liability, however ORRIs may be calculated net of post-production expenses, depending on how the ORRI is structured. ORRIs that are carved out of working interests are linked to the same underlying oil and gas lease that created the working interest, and therefore, such ORRIs are typically subject to expiration upon the expiration or termination of the oil and gas lease.

Our Relationship with Royal Resources, L.P.

Our largest shareholder is Royal, which was formed by a subsidiary of The Blackstone Group L.P. ("Blackstone") in 2011. We were formed pursuant to the Transactions through which Blackstone (through its ownership of Royal) has retained a significant ownership stake in us, representing approximately 41% of our voting interests through Royal's ownership of our Class C common stock. Pursuant to the Contribution Agreement, Blackstone also has the right to nominate six out of eleven members of our Board of Directors. Falcon performs certain managerial operations for Royal with respect to assets that Royal owned that were not contributed to Falcon. For such managerial operations, Falcon is paid less than $0.1 million per quarter, plus reimbursement of certain out of pocket expenses and an allocated amount of certain third-party costs. See also, Part I, Item 1, Business, Corporate History.

Recent Developments

None.

OIL AND NATURAL GAS DATA

Reserves Presentation

Our estimated proved reserves on a historical basis as of December 31, 2019 and 2018 are based on valuations prepared by Ryder Scott and represent 100% of the total net proved liquid hydrocarbon reserves and 100% of the total net proved gas reserves in the Eagle Ford Shale, Marcellus Shale, and Point Pleasant formations as of December 31, 2019. A copy of each of the summary reports of our reserve engineers with respect to our reserves as of 2019 on a historical basis is incorporated by reference herein to Exhibit 99.1 to this Annual Report.

Proved Reserves

Evaluation and Review of Reserves

Our historical reserve estimates as of December 31, 2019 and 2018 were prepared by Ryder Scott. A reserve audit is not the same as a financial audit and is less vigorous in nature than an independent reserve report where the independent reserve engineer determines the reserves on its own.

Ryder Scott is an independent petroleum engineering firm. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Ryder Scott is a third-party engineering firm and does not own an interest in any of our properties and is not employed by us on a contingent basis.

Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible–from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations–prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered." All of our proved reserves as of December 31, 2019 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. The proved reserves for our properties were estimated by performance methods, analogy or a combination of both methods. Approximately 90% of the proved producing reserves attributable to producing wells were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of available historical production and pressure data. The remaining 10% of the proved producing reserves were estimated by analogy, or a combination of performance and analogy methods. The analogy method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate. All proved developed non-producing and undeveloped reserves were estimated by the analogy method.

To estimate economically recoverable proved reserves and related future net cash flows, Ryder Scott considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves included production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

Our petroleum engineers work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets. Our internal technical team members met with our independent reserve engineers periodically during the period covered by the reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. The Vice President–Reservoir Engineering is primarily responsible for overseeing the preparation of all of our reserve estimates. The Vice President–Reservoir Engineering is a petroleum engineer with over 13 years of reservoir and operations experience. Our technical staff uses historical information for our properties such as ownership interest, oil and gas production, well test data, commodity prices, and operating and development costs.

The preparation of our proved reserve estimates are completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by our operators;
- preparation of reserve estimates by the Vice President–Reservoir Engineering or under his direct supervision;
- review by the Vice President–Reservoir Engineering of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions;
- direct reporting responsibilities by the Vice President–Reservoir Engineering to the Chief Operating Officer;
- verification of property ownership by our land department; and
- no employee's compensation is tied to the amount of reserves booked.

The following table presents our estimated net proved oil and natural gas reserves as of December 31, 2019 and 2018 based on the reserve reports prepared by Ryder Scott. Each reserve report has been prepared in accordance with the rules and regulations of the SEC. All of our proved reserves included in the reserve reports are located in the continental United States.

	As of December 31,	
	2019	2018
Estimated proved developed reserves:		
Oil (MBbls)	3,900	3,857
Natural gas (MMcf)	18,016	18,700
Natural gas liquids (MBbls)	1,230	1,293
Total (MBOE)	8,133	8,267
Estimated proved undeveloped reserves:		
Oil (MBbls)	8,696	11,355
Natural gas (MMcf)	28,254	37,485
Natural gas liquids (Bbls)	1,489	1,870
Total (MBOE)	14,894	19,473
Estimated net proved reserves:		
Oil (MBbls)	12,596	15,212
Natural gas (MMcf)	46,270	56,185
Natural gas liquids (MBbls)	2,719	3,163
Total (MBOE) (1)	23,027	27,740
Percent proved developed	35.32%	29.80%
PV-10 of proved reserves (in millions) (2)	$ 487.5	$ 658.6

(1) Estimates of reserves as of December 31, 2019 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the year ended December 31, 2019 in accordance with revised SEC rules and regulations applicable to reserve estimates as of the end of such period. The unweighted arithmetic average first day of the month prices were $55.69 per Bbl for oil and $2.58 per MMBtu for natural gas at December 31, 2019. The price per Bbl for natural gas liquids was modeled as a percentage of oil price, which was derived from historical accounting data. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent Royalties in our properties. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

(2) In this Annual Report, we have disclosed our PV-10 based on our reserve report. PV-10 represents the period end present value of estimated future cash inflows from our natural gas and crude oil reserves, less production costs, discounted at 10% per annum to reflect timing of future cash flows and using SEC pricing requirements in effect at the end of the period. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. PV-10 differs from standardized measure because it does not include the effects of income taxes. However, because we were a limited partnership prior to the Closing of the Transaction, we were generally not subject to federal income taxes and thus historically our PV-10 for proved reserves and standardized measure are equivalent. Neither PV-10 nor standardized measure represents an estimate of fair market value of our natural gas and oil properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of estimated reserves held by companies without regard to the specific tax characteristics of such entities.

As of December 31, 2019, our historical proved developed reserves totaled 3,900 MBbls of oil, 18,016 MMcf of natural gas and 1,230 MBbls of natural gas liquids, for a total of 8,133 MBOE. Of the total proved developed reserves, 82% are producing and the remaining 18% are from wells that have been stimulated but are not yet producing hydrocarbons.

The foregoing reserves are all located within the continental United States. Reserve engineering is a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices, and future production rates and costs. See “Risk Factors” in this Annual Report. We have not filed any estimates of total, proved net oil or natural gas reserves with any federal authority or agency other than the SEC.

Proved Undeveloped Reserves

As of December 31, 2019, our historical proved undeveloped reserves totaled 8,696 MBbls of oil, 28,254 MMcf of natural gas and 1,489 MBbls of natural gas liquids, for a total of 14,894 MBOE. PUD reserves will be converted from undeveloped to developed as the applicable wells begin production.

During the year ended December 31, 2019, our PUD reserves changed due to:

- the conversion of 2,167 MBOE of PUD reserves into PDP and PNP reserves;
- net negative revisions of 1,201 MBOE as a result of the removal of certain locations to the drilling schedule as part of a revised development plan;
- negative revisions of 1,211 MBOE as a result of pricing and revised type curves; and

All of our PUD drilling locations are scheduled to be drilled prior to the end of December 2024. This development schedule is based on a 122 well inventory waiting to be brought online, 88 permits that identify activity and continued PUD conversion based on historical drilling activity and the publicly announced capital expenditure plans of our operators. As an owner of Royalties and not working interests, the contributed Royal Entities were not required to make capital expenditures and did not make capital expenditures to convert PUD reserves from undeveloped to developed.

Identification of Drilling Locations

Our identification of drilling locations is based on specifically identified locations on our leasehold acreage based on our assessment of current geoscientific, engineering, land, well-spacing and historic production profile information derived from state agencies and public statements by our operators on the acreage underlying our interests. These drilling locations are identified on a detailed map and allocated a reserve profile and identifier. Further, Ryder Scott reviewed and confirmed our drilling locations in estimating our PUD reserves in connection with the preparation of our reserve report as of December 31, 2019. We update and revise our drilling locations on a periodic basis as our assessment of the information described above changes.

Production and Price History

The following table sets forth information regarding our net production of oil, natural gas and natural gas liquids, substantially all of which is from the Eagle Ford Shale region in South Texas, and certain price and cost information for each of the periods indicated:

	As of December 31,		
	2019	2018	2017
Production Data:			
Eagle Ford Shale:			
Oil (Bbls)	876,140	1,154,827	1,402,729
Natural gas (Bbls)	358,804	467,107	513,850
Natural gas liquids (Bbls)	276,656	259,924	493,334
Combined volumes (BOE)	1,511,600	1,881,858	2,409,913
Average daily combined volume (BOE/d)	4,141	5,156	6,603
Total:			
Oil (Bbls)	879,288	1,237,813	1,582,322
Natural gas (Bbls)	598,019	686,279	760,982
Natural gas liquids (Bbls)	296,813	293,086	542,706
Combined volumes (BOE)	1,774,120	2,217,178	2,886,010
Average daily combined volume (BOE/d)	4,861	6,074	7,907
% Oil	50%	56%	55%
Average sales prices:			
Oil (Bbls)	$ 59.85	$ 67.14	$ 50.54
Natural gas (Mcf)	$ 2.62	$ 3.10	$ 2.81
Natural gas liquids (Bbls)	$ 15.45	$ 25.62	$ 20.63
Combined per (BOE)	$ 37.54	$ 46.63	$ 35.67
Average Costs ($/BOE):			
Production and ad valorem taxes	$ 2.40	$ 2.32	$ 1.82
Gathering and transportation expense	$ 1.35	$ 1.07	$ 2.25
General and administrative	$ 6.71	$ 4.30	$ 2.85
Interest expense, net	$ 1.40	$ 1.06	$ 0.95
Depletion	$ 7.18	$ 7.65	$ 11.72

Producing Wells

As of December 31, 2019, we owned Royalties in 2,260 producing wells located on the acreage in which we had an interest. The following table provides detailed information relating to our producing wells:

	Gross Producing Wells	Net Producing Wells
Oil	1,924	24
Natural Gas	336	6
Total	2,260	30

Acreage

The following tables set forth information as of December 31, 2019 relating to total gross and net acreage in the units associated with Royalties owned by us:

Basin	Gross Developed Acreage [(1)]	Gross Undeveloped Acreage [(2)]	Total Gross Acreage
Eagle Ford Shale	76,960	107,593	184,553
Marcellus Shale and Point Pleasant	26,880	47,815	74,695
Total	103,840	155,408	259,248

Basin	Net Developed Acreage [(1)]	Net Undeveloped Acreage [(2)]	Total Net Acreage
Eagle Ford Shale	959	1,711	2,670
Marcellus Shale and Point Pleasant	468	1,062	1,530
Total	1,427	2,773	4,200

(1) Developed acres are acres spaced or assigned to productive wells and do not include undrilled acreage held by production under the terms of the lease. The value provided is for horizontal wells only and are based on 40 acres per well in the Eagle Ford Shale and 80 acres per well in the Marcellus Shale and Point Pleasant formation for wells drilled as of December 31, 2019.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

Drilling Results

As of December 31, 2019, our operators associated with Royalties had 122 wells in the process of drilling, completing or dewatering or shut in awaiting infrastructure that are not reflected in the table below. The following table sets forth for the periods indicated below, the number of net productive and dry wells completed, regardless of when drilling was initiated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value.

	Year Ended December 31,		
	2019	2018	2017
Development:			
Productive	194	235	193
Dry	-	-	-

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position.

Our ability to acquire additional mineral, royalty, overriding royalty, net profits and similar interests in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for these and other oil and natural gas properties. Further, oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal, and fuel oils. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

Seasonal Nature of Business

Generally, demand for oil increases during the summer months and decreases during the winter months while natural gas decreases during the summer months and increases during the winter months. Certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit drilling and producing activities and other oil and natural gas operations in a portion of our operating areas. These seasonal anomalies can pose challenges for our operators in meeting well drilling objectives and can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay operations.

Regulation

The following disclosure describes regulation more directly associated with operators of oil and natural gas properties, including our current operators, and other owners of working interests in oil and natural gas properties. To the extent we elect in the future to engage in the exploration, development and production of oil and natural gas properties, we would be directly subject to the same regulations described below.

Oil and natural gas operations are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. This legislation and regulation affecting the oil and natural gas industry is under constant review for amendment or expansion. Some of these requirements carry substantial penalties for failure to comply. The regulatory burden on the oil and natural gas industry increases the cost of doing business.

Environmental Matters

Oil and natural gas exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. Numerous federal, state and local governmental agencies, such as the Environmental Protection Agency ("EPA"), issue regulations that often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing earthen pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from operations. The strict and joint and several liability nature of such laws and regulations could impose liability upon responsible parties (including the operators of the acreage underlying our Royalties) regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect Falcon's business and prospects.

Waste Handling

The Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of crude oil and natural gas are exempt from regulation as hazardous wastes under RCRA, such wastes may constitute "solid wastes" that are subject to the less stringent requirements of non-hazardous waste provisions. However, there is no guarantee that the EPA or state or local governments will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. For example, in December 2016, the EPA and several environmental groups entered into a consent decree to address the EPA's alleged failure to timely assess its regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking no later than March 15, 2019, for revision of certain regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. If the EPA proposes revised oil and gas regulations, the consent decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Legislation has also been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as "hazardous wastes." Any such changes in the laws and regulations could have a material adverse effect on the capital expenditures and operating expenses of the operators of the acreage underlying our Royalties.

Administrative, civil, and criminal penalties can be imposed on the operators of the acreage underlying Falcon's Royalties for failure to comply with waste handling requirements. Any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase the costs to manage and dispose of wastes for such operators.

Remediation of Hazardous Substances

The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as the "Superfund" law, and analogous state laws, generally impose strict and joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current owner or operator of a contaminated facility, a former owner or operator of the facility at the time of contamination, and those persons that disposed or arranged for the disposal of the hazardous substance at the facility. Under CERCLA and comparable state statutes, persons deemed "responsible parties" may be subject to strict and joint and several liability for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In addition, the risk of accidental spills or releases could expose the operators of the acreage underlying Falcon's Royalties to significant liabilities that could have a material adverse effect on the operators' businesses, financial condition and results of operations. Liability for any contamination under these laws could require the operators of the acreage underlying Falcon's Royalties to make significant expenditures to investigate and remediate such contamination or attain and maintain compliance with such laws and may otherwise have a material adverse effect on their results of operations, competitive position or financial condition.

Water Discharges

The Federal Water Pollution Control Act of 1972, as amended, also known as the "Clean Water Act," the Safe Drinking Water Act ("SDWA"), the Oil Pollution Act ("OPA"), and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. These laws and regulations also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers ("Corps"). In addition, the EPA and the Corps released a rule to revise the definition of "waters of the United States" ("WOTUS") for all CWA programs, which went into effect in August 2015. In October 2015, the U.S. Court of Appeals for the Sixth Circuit stayed the rule revising the WOTUS definition nationwide pending further action of the court. In response to this decision, the EPA and the Corps resumed nationwide use of the agencies' prior regulations defining the term "waters of the United States." However, in January 2018, the U.S. Supreme Court ruled that the rule revising the WOTUS definition must be reviewed first in the federal district courts, which resulted in a withdrawal of the stay by the Sixth Circuit. In addition, the EPA has proposed to repeal the rule revising the WOTUS definition, and in January 2018 EPA released a final rule that delays implementation of the rule revising the WOTUS definition until 2020 to allow time for EPA to reconsider the definition of "waters of the United States." Several states and environmental groups have since filed lawsuits challenging the delay rule. To the extent the rule revising the WOTUS definition is implemented, it could significantly expand federal control of land and water resources across the United States, triggering substantial additional permitting and regulatory requirements.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of the facilities on the acreage underlying our Royalties. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. In addition, in June 2016, the EPA finalized wastewater pretreatment standards that prohibit onshore unconventional oil and natural gas extraction facilities from sending wastewater to publicly-owned treatment works; for certain facilities, compliance is required by August 29, 2019. This pending restriction of disposal options for hydraulic fracturing waste and other changes to CWA requirements may result in increased costs.

The OPA is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Noncompliance with the Clean Water Act or OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations, for the operators of the acreage underlying the Company's Royalties.

Air Emissions

The federal Clean Air Act and comparable state laws and regulations regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. For example, in August 2012, the EPA adopted new regulations under the Clean Air Act that established new emission control requirements for oil and natural gas production and processing operations. In addition, in October 2015, the EPA lowered the National Ambient Air Quality Standard, ("NAAQS") for ozone from 75 to 70 parts per billion for both the 8- hour primary and secondary standards, and the agency completed attainment/non-attainment designations in July 2018. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit the ability of our operators to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. Separately, in June 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. These laws and regulations may increase the costs of compliance for oil and natural gas producers and impact production on our properties, and federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Moreover, obtaining or renewing permits has the potential to delay the development of oil and natural gas exploration and development projects. All of these factors could impact production on our properties and adversely affect our business and results of operations.

Climate Change

In response to findings that emissions of greenhouse gases ("GHGs"), including carbon dioxide and methane, present an endangerment to public health and the environment, the EPA has adopted regulations to restrict GHG emissions under existing provisions of the federal Clean Air Act. As discussed in the "Climate Change" risk factor below, EPA has finalized rules that set additional emissions limits for volatile organic compounds and established new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, and transmission and storage activities. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHGs from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis.

In 2015, the United States participated in the United Nations Climate Change Conference, which led to the creation of the Paris Agreement. The Paris Agreement requires member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. In June 2017, the United States announced its withdrawal from the Paris Agreement, although the earliest possible effective date of withdrawal is November 2020. Despite the planned withdrawal, certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement. In addition, Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and many states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs.

In addition, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. Extreme weather conditions can interfere with production and increase costs and damage resulting from extreme weather may not be fully insured. However, at this time, the Company is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting Falcon's business.

Regulation of Hydraulic Fracturing

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal SDWA regulates the underground injection of substances through the Underground Injection Control ("UIC") program. Hydraulic fracturing generally is exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions. However, as discussed in the "Hydraulic Fracturing" risk factor below, in recent year efforts have been made to regulate hydraulic fracturing at the federal level.

In addition, several states, including Texas, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. The Texas Legislature previously adopted legislation requiring oil and gas operators to publicly disclose the chemicals used in the hydraulic fracturing process, effective as of September 1, 2011. The Texas Railroad Commission subsequently adopted rules and regulations implementing this legislation that apply to all wells for which the Railroad Commission issues an initial drilling permit. This law requires that the well operator disclose the list of chemical ingredients subject to the requirements of the Occupational Safety and Health Act for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission. Further, in May 2013, the Texas Railroad Commission issued a "well integrity rule," which updates the requirements for drilling, putting pipe down, and cementing wells. The rule also includes new testing and reporting requirements, such as: (i) the requirement to submit cementing reports after well completion or after cessation of drilling, whichever is later; and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The well integrity rule took effect in January 2014. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibit the performance of well drilling in general or hydraulic fracturing in particular.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative or regulatory changes could cause operators of the operation on the acreage underlying our Royalties to incur substantial compliance costs, and compliance or the consequences of any failure to comply by operators could have a material adverse effect on our financial condition and results of operations.

In addition, hydraulic fracturing operations require the use of a significant amount of water, and the inability of the operators of the acreage underlying our Royalties to locate sufficient amounts of water or dispose of or recycle water used in their drilling and production operations, could adversely impact their operations. Moreover, new environmental initiatives and regulations could include restrictions on the ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the development or production of natural gas.

Finally, in some instances, the operation of underground injection wells has been alleged to cause earthquakes. Such issues have sometimes led to orders prohibiting continued injection or the suspension of drilling in certain wells identified as possible sources of seismic activity. Such concerns also have resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. Future orders or regulations addressing concerns about seismic activity from well injection could affect operations on the acreage underlying our Royalties.

Endangered Species Act

Some of the operations on acreage underlying our Royalties may be located in areas that are designated as habitats for endangered or threatened species under the Endangered Species Act. In February 2016, the U.S. Fish and Wildlife Service published a final policy which alters how it identifies critical habitat for endangered and threatened species. A critical habitat designation could result in further material restrictions to federal and private land use and could delay or prohibit land access or development. Moreover, the U.S. Fish and Wildlife Service continues to make listing decisions and critical habitat designations where necessary, including for over 250 species as required under a 2011 settlement approved by the U.S. District Court for the District of Columbia, and many hundreds of additional anticipated listing decisions have already been identified beyond those recognized in the 2011 settlement. The designation of previously unprotected species as being endangered or threatened, if located in the areas where we have Royalties, could cause the operators of the operations on the acreage underlying our Royalties to incur additional costs or become subject to operating restrictions in areas where the species are known to exist.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases the cost of doing business, these burdens generally do not affect the Company any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission (“FERC”). Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. FERC’s regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. The Company cannot predict whether new legislation to regulate oil and natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on Falcon’s operations. Sales of condensate and oil and natural gas liquids are not currently regulated and are made at market prices.

Drilling and Production

The operations of the Company's operators are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The state, and some counties and municipalities, in which the Company operates also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities, including seasonal wildlife closures;
- the rates of production or "allowables";
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce the Company's interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas that the Company's operators can produce from our wells or limit the number of wells or the locations at which operators can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but we cannot assure you that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or to limit the number of locations operators can drill.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where the operators of the acreage underlying our Royalties operate. The U.S. Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Although the U.S. Army Corps of Engineers does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

Natural Gas Sales and Transportation

Historically, federal legislation and regulatory controls have affected the price and marketing of natural gas. FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in "first sales." Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which our operators may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that our operators produce, as well as the revenues our operators receive for sales of natural gas and release of natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas-related activities.

Under FERC's current regulatory regime, transmission services must be provided on an open-access, nondiscriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in-state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. Although its policy is still in flux, FERC has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our operators' costs of transporting gas to point-of-sale locations.

Oil Sales and Transportation

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any materially different way than such regulation will affect the operations of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by portioning provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to our operators to the same extent as to the Company or their competitors.

State Regulation

Texas regulates the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Texas currently imposes a 4.6% severance tax on the market value of oil production and a 7.5% severance tax on the market value of natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations our operators can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Employees

As of December 31, 2019, Falcon had 12 full-time employees. None of Falcon's employees are represented by labor unions or covered by any collective bargaining agreements. Falcon also hires independent contractors and consultants involved in land, technical, regulatory and other disciplines to assist its full-time employees. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes, each of which is included elsewhere in this Annual Report.

Facilities

Our executive offices are located at 510 Madison Avenue, 8th Floor, New York, NY 10022. Our executive offices are shared with Hepco Capital Management, LLC ("Hepco"), which Company directors Edward Cohen and Jonathan Cohen are also directors of. The related cost of our executive offices is proportionately shared between the Company and Hepco. We have additional leased office space in Philadelphia, PA and Houston, TX. We believe that these facilities are adequate for our current operations.

Available Information

We maintain an Internet website at www.falconminerals.com. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports are available free of charge on the Investor Relations page of our website at www.falconminerals.com as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Information contained on, or connected to, our website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

ITEM 1A. RISK FACTORS

The following risk factors apply to our business and operations. These risk factors are not exhaustive and investors are encouraged to perform their own investigation with respect to our business, financial condition and prospects. You should carefully consider the following risk factors in addition to the other information included in this annual report, including matters addressed in the section entitled "Cautionary Statement Regarding Forward-Looking Statements." We may face additional risks and uncertainties that are not presently known to us, or that we currently deem immaterial, which may also impair our business or financial condition.

The following discussion should be read in conjunction with our financial statements and notes to the financial statements included herein.

Risks Related to Our Business

A majority of our revenues are derived from royalty payments that are based on the price at which oil, natural gas and natural gas liquids produced from the underlying acreage is sold. The volatility of these prices due to factors beyond our control greatly affects our business, financial condition and results of operations.

Our revenues, operating results and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for oil and natural gas. Oil and natural gas are commodities, and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, oil and natural gas prices have been volatile and they are likely to remain volatile due to a variety of additional factors that are beyond our control, including:

- worldwide and regional economic conditions affecting the global supply of and demand for oil and natural gas;
- global or national health concerns, including the outbreak of pandemic or contagious disease, such as the current coronavirus situation, which may reduce demand for oil and gas because of reduced global or national economic activity;
- the level of prices and expectations about future prices of oil and natural gas;
- political and economic conditions in oil producing countries, including the Middle East, Africa, South America and Russia;
- the level of global oil and natural gas exploration and production;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the price and quantity of foreign imports;
- increases in U.S. domestic production;
- the ability of members of the Organization of Petroleum Exporting Countries (“OPEC”) to agree to and maintain oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and other natural disasters;
- risks associated with operating drilling rigs;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxes;
- the proximity, cost, availability and capacity of oil and natural gas pipelines and other transportation facilities; and
- the price and availability of competitors’ supplies of oil and natural gas and alternative fuels.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our financial condition and results of operations.

In addition, lower oil and natural gas prices may also reduce the amount of oil and natural gas that can be produced economically by our operators. This may result in having to make substantial downward adjustments to our estimated proved reserves. Our operators could also determine during periods of low commodity prices to shut in or curtail production from wells on the properties underlying its royalties. In addition, they could determine during periods of low commodity prices to plug and abandon marginal wells that otherwise may have been allowed to continue to produce for a longer period under conditions of higher prices. Specifically, they may abandon any well if they reasonably believe that the well can no longer produce oil or natural gas in commercially paying quantities thereby potentially causing some or all of the underlying oil and gas lease to expire along with our royalties therein.

The ability or willingness of OPEC and other oil exporting nations to set and maintain production levels has a significant impact on oil and natural gas commodity prices.

OPEC is an intergovernmental organization that seeks to manage the price and supply of oil on the global energy market. Actions taken by OPEC members, including those taken alongside other oil exporting nations, have a significant impact on global oil supply and pricing. For example, OPEC and certain other oil exporting nations have previously agreed to take measures, including production cuts, to support crude oil prices. In March 2020, members of OPEC and Russia considered extending and potentially increasing these oil production cuts. However, these negotiations were unsuccessful. As a result, Saudi Arabia announced an immediate reduction in export prices and Russia announced that all previously agreed oil production cuts will expire on April 1, 2020. These actions led to an immediate and steep decrease in oil prices. There can be no assurance that OPEC members and other oil exporting nations will agree to future production cuts or other actions to support and stabilize oil prices, nor can there be any assurance that they will not further reduce oil prices or increase production. Uncertainty regarding future actions to be taken by OPEC members or other oil exporting countries could lead to increased volatility in the price of oil, which could adversely affect our business, financial condition and results of operations.

We depend on four third-party operators for substantially all of the exploration and production on the properties underlying our royalties. Substantially all of our revenue is derived from royalty payments made by these operators. Therefore, any reduction in production from the wells drilled on our acreage by these operators or the failure of our operators to adequately and efficiently develop and operate our acreage could have a material adverse effect on our revenues, financial condition and results of operations. None of the operators of the properties underlying our royalties are contractually obligated to undertake any development activities, so any development and production activities will be subject to their discretion.

Because we depend on third-party operators for all of the exploration, development and production on our properties, we have no control over the operations related to our properties. For the year ended December 31, 2019, we received approximately 33%, 29%, 18% and 3% of our revenue from ConocoPhillips Company ("ConocoPhillips"), EOG Resources, Inc. ("EOG"), Devon Energy Corporation ("Devon"), and BP Plc ("BP"), respectively. The failure of the aforementioned operators to adequately or efficiently perform operations or an operator's failure to act in ways that are in our best interests could reduce production and revenues. Further, none of the operators of the properties underlying our royalties are contractually obligated to undertake any development activities, so any development and production activities will be subject to their reasonable discretion. The success and timing of drilling and development activities on the properties underlying our royalties, therefore, depends on a number of factors that will be largely outside of our control, including:

- the ability of our operators to access capital;
- the availability of suitable drilling equipment, production and transportation infrastructure and qualified operating personnel;
- the operators' expertise, operating efficiency and financial resources;
- approval of other participants in drilling wells;
- the selection of technology;
- the selection of counterparties for the sale of production; and
- the rate of production of the reserves.

The third-party operators may elect not to undertake development activities, or may undertake such activities in an unanticipated fashion, which may result in significant fluctuations in our revenues, financial condition and results of operations. If reductions in production by the operators are implemented on the properties underlying our royalties and sustained, our revenues may also be substantially affected. Additionally, if an operator were to experience financial difficulty, the operator might not be able to pay its royalty payments or continue its operations, which could have a material adverse impact on us.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures from our operators than we or they currently anticipate.

As of December 31, 2019, 64.7% of our total estimated proved reserves were proved undeveloped reserves and may not be ultimately developed or produced by our operators. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations by our operators. The reserve data included in the reserve report of our independent petroleum engineer assume that substantial capital expenditures by our operators are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that our operators will develop the properties underlying our royalties as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical for our operators. In addition, delays in the development of reserves could force us to reclassify certain of our proved reserves as unproved reserves.

Our producing properties are located predominantly in the Eagle Ford Shale region of South Texas, making us vulnerable to risks associated with operating in a single geographic area. In addition, we have a large amount of proved reserves attributable to a single producing horizon within this area.

The majority of our properties are geographically concentrated in Karnes, DeWitt, and Gonzales Counties in the Eagle Ford Shale region of South Texas. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, availability of equipment, facilities, personnel or services market limitations or interruption of the processing or transportation of crude oil, natural gas or natural gas liquids. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Eagle Ford Shale region, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our properties, they could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

Our success depends on finding or acquiring additional reserves, and our operators developing those additional reserves.

Our future success depends upon our ability to acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that successful exploration or development activities are conducted on the properties underlying our royalties by our operators or we acquire properties containing proved reserves, or both. Aside from acquisitions, we have no control over the exploration and development of our properties. To increase reserves and production, we would need our operators to undertake replacement activities or use third parties to accomplish these activities. Substantial capital expenditures will be necessary for the acquisition of oil and natural gas reserves. Neither we nor our third-party operators may have sufficient resources to acquire additional reserves or to undertake exploration, development, production or other replacement activities, such activities may not result in significant additional reserves and efforts to drill productive wells at low finding and development costs may be unsuccessful. Furthermore, although our revenues may increase if prevailing oil and natural gas prices increase significantly, finding costs for additional reserves could also increase.

Our failure to successfully identify, complete and integrate acquisitions of properties or businesses could slow our growth and adversely affect our financial condition and results of operations.

There is intense competition for acquisition opportunities in our industry. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain, and we may not be able to identify attractive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. Unless our operators further develop our existing properties, we will depend on acquisitions to grow our reserves, production, and cash flow.

Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Further, these acquisitions may be in geographic regions in which we do not currently hold properties, which could result in unforeseen operating difficulties. In addition, if we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements. Compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities and increase our exposure to penalties or fines for non-compliance with such additional legal requirements. Further, the success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions.

No assurance can be given that we will be able to identify suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our growth and results of operations.

We may acquire properties that do not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with such properties or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not necessarily reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Identified drilling locations, which are scheduled out over many years, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Proved undeveloped drilling locations represent a significant part of our growth strategy, however, we do not control the development of these locations. Our operators' ability to drill and develop identified potential drilling locations will depend on a number of factors, including the availability of capital, seasonal conditions, regulatory changes and approvals, negotiation of agreements with third-parties, commodity prices, costs, the generation of additional seismic or geological information, the availability of drilling rigs, drilling results, construction of infrastructure, inclement weather, and lease expirations.

Further, identified potential drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional analysis of data. We will not be able to predict in advance of drilling and testing whether any particular drilling location will yield production in sufficient quantities for operators to recover drilling or completion costs or to be economically viable. Even if sufficient amounts of oil or natural gas reserves exist, the potentially productive hydrocarbon bearing formation may be damaged or mechanical difficulties may develop while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If our operators drill dry holes in our current and future drilling locations, our business may be materially harmed. We will not be able to assure you that the analogies drawn from available data from other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or our operators in our areas of operations may not be indicative of future or long-term production rates.

Because of these uncertainties, we do not know if the potential drilling locations identified on our acreage will ever be drilled or if oil or natural gas reserves will be able to be produced from these or any other potential drilling locations. As such, actual drilling activities with respect to our acreage may materially differ from those presently identified, which could adversely affect our business, financial condition and results of operations.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present value of our reserves.

Oil and natural gas reserve engineering is not an exact science and requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, ultimate recoveries and operating and development costs. As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may be incorrect.

Our historical estimates of proved reserves and related valuations as of December 31, 2019, were prepared by Ryder Scott, an independent petroleum engineering firm, which conducted a well-by-well review of all of our properties for the period covered by its reserve report using information provided by us. Over time, we may make material changes to reserve estimates taking into account the results of actual drilling, testing and production. Also, certain assumptions regarding future oil and natural gas prices, production levels and operating and development costs may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of future net cash flows. In addition, none of the operators of the properties underlying our royalties are contractually obligated to provide us with information regarding drilling activities or historical production data with respect to the properties underlying our interests, which may affect our estimates of reserves. A substantial portion of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil and natural gas that are ultimately recovered being different from our reserve estimates.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

The estimates of reserves as of December 31, 2019 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the year ended December 31, 2019, in accordance with the revised SEC rules and regulations applicable to reserve estimates for such period.

SEC rules and regulations could limit our ability to book additional proved undeveloped reserves in the future.

SEC rules and regulations require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional proved undeveloped reserves as our operators pursue their drilling programs. Moreover, we may be required to write down our proved undeveloped reserves if those wells are not drilled within the required five-year time frame.

The PV-10 of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil and natural gas reserves.

The present value of future net cash flows from our proved reserves shown in this report, or PV-10, may not be the current market value of our estimated natural gas and oil reserves. In accordance with rules established by the SEC and the Financial Accounting Standards Board ("FASB"), we base the estimated discounted future net cash flows from our proved reserves on the historical 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Unless we replace our reserves with new reserves that our operators develop, our reserves royalty payments will decline, which would adversely affect our future cash flows and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless our operators conduct successful ongoing development and exploration activities or we continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future natural gas reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our operators' success in efficiently developing and exploiting our current reserves and we economically finding or acquiring additional recoverable reserves. We may not be able to find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

Declining general economic, business or industry conditions could have a material adverse effect on our financial condition and results of operations.

Declines in general economic, business or industry conditions, including expectations of future declines or uncertainty with respect to such conditions, could adversely affect our financial condition and results of operations. Volatility in prices of oil, natural gas and natural gas liquids, as well as concerns about global economic growth, could also impact the price at which oil, natural gas and natural gas liquids from the properties underlying our royalties are sold, affect the ability of vendors, suppliers and customers associated with the properties underlying our royalties to continue operations and ultimately adversely impact our financial condition and results of operations.

Outbreaks of communicable diseases could adversely affect our business, financial condition and results of operations.

Global or national health concerns, including the outbreak of pandemic or contagious disease, can negatively impact the global economy and, therefore, demand and pricing for oil and natural gas products. For example, there have been recent outbreaks in several countries, including the United States, of a highly transmissible and pathogenic coronavirus ("COVID-19"). The outbreak of communicable diseases, or the perception that such an outbreak could occur, could result in a widespread public health crisis that could adversely affect the economies and financial markets of many countries, resulting in an economic downturn that would negatively impact the demand for oil and natural gas products. Furthermore, uncertainty regarding the impact of any outbreak of pandemic or contagious disease, including COVID-19, could lead to increased volatility in oil and natural gas prices. The occurrence or continuation of any of these events could lead to decreased revenues and limit our ability to execute on our business plan, which could adversely affect our business, financial condition and results of operations.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition and results of operations.

Competition in the oil and natural gas industry is intense, which may adversely affect our third-party operators' ability to succeed.

The oil and natural gas industry is intensely competitive, and our third-party operators compete with other companies that may have greater resources. Many of these companies explore for and produce oil and natural gas, carry on midstream and refining operations, and market petroleum and other products on a regional, national or worldwide basis. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our operators' larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than our operators can, which would adversely affect our operators' competitive position. Our operators may have fewer financial and human resources than many companies in our operators' industry and may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

Increased costs of capital could adversely affect our business.

Our business and ability to make acquisitions could be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in our credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, and place us at a competitive disadvantage. A significant reduction in the availability of capital could materially and adversely affect our ability to achieve our planned growth and operating results.

The oil and gas operations on the acreage underlying our royalties are subject to environmental, health and safety laws and regulations that could adversely affect the cost, manner or feasibility of conducting operations on them or result in significant costs and liabilities, which could adversely affect our financial condition and results of operations.

The oil and natural gas exploration and production operations on the acreage underlying our royalties are subject to stringent and comprehensive federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection or the health and safety of workers and other affected individuals. These laws and regulations may impose numerous obligations that apply to the operations on the acreage underlying our royalties, including the requirement to obtain a permit before conducting drilling, waste disposal or other regulated activities; the restriction of types, quantities and concentrations of materials that can be released into the environment; restrictions on water withdrawal and use; the incurrence of significant development expenses to install pollution or safety-related controls at the operated facilities; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the protection of threatened or endangered species; and the imposition of substantial liabilities for pollution resulting from operations.

There is an inherent risk of incurring significant environmental costs and liabilities in the operations on the acreage underlying our royalties as a result of the handling of petroleum hydrocarbons and wastes, air emissions and wastewater discharges related to operations, and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, the operators could be subject to joint and several strict liability for the removal or remediation of previously released materials or property contamination regardless of whether such operators were responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties on or adjacent to well sites and facilities where petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. In addition, the risk of accidental spills or releases could expose the operators of the acreage underlying our royalties to significant liabilities that could have a material adverse effect on the operators' businesses, financial condition and results of operations.

Changes in environmental laws and regulations occur frequently, and any changes that result in delays or restrictions in permitting or development of projects, more stringent or costly operational control requirements, or waste handling, storage, transport, disposal or cleanup requirements could require the operators of the acreage underlying our royalties to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on their results of operations, competitive position or financial condition.

Climate change laws and regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas produced from the acreage underlying our royalties, while potential physical effects of climate change could disrupt production and cause operators to incur significant costs in preparing for or responding to those effects.

In response to U.S. Environmental Protection Agency ("EPA") findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment, the EPA has adopted regulations to restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In May 2016, the EPA finalized rules that set additional emissions limits for volatile organic compounds and established new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The rule includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. In June 2017, the EPA issued a proposal to stay certain of these requirements for two years and reconsider the entirety of the 2016 rules; however, the rules currently remain in effect. In addition, in April 2018, a coalition of states filed a lawsuit in the U.S. District Court for the District of Columbia aiming to force the EPA to establish guidelines for limiting methane emissions from existing sources in the oil and natural gas sector; that lawsuit is pending. These rules may require operators on the acreage underlying our royalties to incur additional expenses to control air emissions by installing emissions control technologies and adhering to a variety of work practice and other requirements. These requirements could increase the costs of development and production, reducing the profits available to us and potentially impairing our operator's ability to economically develop acreage underlying our royalties. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of the operations conducted on the acreage underlying our royalties.

In addition, in 2015, the United States participated in the United Nations Climate Change Conference, which led to the creation of the Paris Agreement. The Paris Agreement requires member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. In June 2017, the United States announced its withdrawal from the Paris Agreement, although the earliest possible effective date of withdrawal is November 2020. Despite the planned withdrawal, certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement. While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. Any such future laws and regulations imposing reporting obligations on, or limiting emissions of, GHGs could require operators of the acreage underlying our royalties to incur costs to reduce emissions of GHGs. Substantial limitations on GHG emissions could adversely affect demand for oil and natural gas.

Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have a material adverse effect on the operations conducted on the acreage underlying our royalties.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing, including with respect to seismic activity allegedly related to hydraulic fracturing, could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect production on the acreage underlying our royalties.

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing is typically regulated by state oil and natural gas commissions. However, in February 2014, the EPA published permitting guidance under the federal Safe Drinking Water Act ("SDWA") addressing the use of diesel fuels in certain hydraulic fracturing activities, and in May 2014, the EPA issued an Advance Notice of Proposed Rulemaking seeking comment on the development of regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. Further, in March 2015, the Bureau of Land Management ("BLM") of the U.S. Department of the Interior published a final rule imposing requirements for hydraulic fracturing activities on federal and Indian lands, including new requirements relating to public disclosure, wellbore integrity and handling of flowback water. Following years of litigation, the BLM rescinded the rule in December 2017. However, in January 2018, California and several environmental groups filed lawsuits challenging BLM's rescission of the rule; those lawsuits are pending. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. If enacted, these or similar laws could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations and increased costs on the acreage underlying our royalties.

There may be other attempts to further regulate hydraulic fracturing under the SDWA, TSCA and/or other statutory or regulatory mechanisms. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibit the performance of well drilling in general or hydraulic fracturing in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we hold royalties, the operators of the acreage underlying our royalties could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development activities, and perhaps even be precluded from drilling wells.

In some instances, the operation of underground injection wells has been alleged to cause earthquakes. Such issues have sometimes led to orders prohibiting continued injection or the suspension of drilling in certain wells identified as possible sources of seismic activity. Such concerns also have resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. Future orders or regulations addressing concerns about seismic activity from well injection could affect operations on the acreage underlying our royalties.

New environmental initiatives and regulations could include restrictions on the ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the development or production of natural gas. Also, the threat of climate change has resulted in increasing political risks in the United States, including climate-related pledges to ban hydraulic fracturing of oil and gas wells being made by certain candidates seeking the office of President of the United States in 2020. Additionally, Senator Bernie Sanders (D-VT), who is one of the presidential candidates that has pledged to ban hydraulic fracturing, introduced Senate Bill 3247 on January 28, 2020 that, if enacted as proposed, would ban hydraulic fracturing nationwide by 2025. Any of these environmental initiatives and regulations, including the proposed ban, could have a material adverse effect on our financial condition and results of operations.

We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, and processing activities. For example, the oil and natural gas industry depends on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering systems, conduct reservoir modeling and reserves estimation, and process and record financial and operating data. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our technologies, systems, networks, and those of our vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient. As cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. We do not maintain specialized insurance for possible liability resulting from a cyberattack on our assets that may shut down all or part of our business.

Our only significant assets are the ownership of the general partner interest and its limited partner interest in OpCo, and such ownership may not be sufficient to enable us to pay any dividends on our Class A common stock or satisfy our other financial obligations.

We have no direct operations and no significant assets other than the ownership of the general partner interest and a 53% limited partner interest in OpCo. We depend on OpCo and its subsidiaries for distributions, loans and other payments to generate the funds necessary to meet our financial obligations or to pay any dividends with respect to our Class A common stock. Subject to certain restrictions, OpCo generally will be required to (i) as discussed below, make quarterly pro rata tax distributions to its partners, including us, in an amount equal to 50% of the total federal taxable income allocated by OpCo to the limited partners and (ii) reimburse us for certain corporate and other overhead expenses. However, legal and contractual restrictions in agreements governing future indebtedness of OpCo and its subsidiaries, as well as the financial condition and operating requirements of OpCo and its subsidiaries, may limit our ability to obtain cash from OpCo. The earnings from, or other available assets of, OpCo and its subsidiaries, may not be sufficient to enable us to pay any dividends on our Class A common stock or satisfy our other financial obligations. OpCo is treated as a partnership for U.S. federal income tax purposes and, as such, is not subject to any entity-level U.S. federal income tax. Instead, taxable income is allocated to holders of its common units, including us. As a result, we generally will incur income taxes on our allocable share of any net taxable income of OpCo. Under the terms of the OpCo Limited Partnership Agreement, OpCo will be obligated to make tax distributions to holders of its common units, including us, equal to 50% of the total federal taxable income allocated by OpCo to the limited partners, except to the extent such distributions would render OpCo insolvent or are otherwise prohibited by law or any of our current or future debt agreements. In addition to tax expenses, we will also incur expenses related to our operations, our interests in OpCo and related party agreements, and expenses and costs of being a public company, all of which could be significant. To the extent that we need funds and OpCo or its subsidiaries is restricted from making such distributions under applicable law or regulation or under the terms of their financing arrangements, or are otherwise unable to provide such funds, it could materially adversely affect our liquidity and financial condition, including our ability to pay our income taxes when due.

We may change our dividend policy at any time and there is no guarantee that we will pay dividends in the future.

Although we currently plan to pay out substantially all of our free cash flow in the form of a regular quarterly dividend, there is no guarantee or requirement that we pay dividends in the future. Our organizational documents, including the Second Amended & Restated Charter, only require our Board of Directors or us to make any dividends or distributions to the holders of Class A common stock in certain limited circumstances that are generally within the control of our Board of Directors. Our dividend policy may change at any time without notice to our stockholders. The declaration and amount of any future dividends to holders of our Class A common stock will be at the discretion of our Board of Directors in accordance with applicable law and after taking into account various factors, including our financial condition, results of operations, current and anticipated cash needs, cash flows, impact on our effective tax rate, indebtedness, contractual obligations, legal requirements and other factors that our Board of Directors deems relevant. As a result, we cannot assure you that we will pay dividends at any rate or at all.

The Contributors own an amount of Class C common stock that provides them with effective control over us.

At the closing of the Business Combination, the Contributors received $400 million of cash and 40 million Opco common units (together with 40 million shares of Class C common stock). As a result, the Contributors hold approximately 47% of the voting power over us. This voting percentage may provide the Contributors with effective control over us. In addition, we have agreed to provide Blackstone with a right to nominate six out of 11 of the directors on our Board of Directors so long as Blackstone, together with its affiliates, holds at least 40% of the voting power over our common stock. Blackstone and the Contributors may exercise their control in a way that favors its respective interests to the detriment of the other stockholders of us.

Restrictions in the Revolving Credit Facility and future debt agreements of us and Opco could limit its growth and its ability to engage in certain activities.

At the closing of the Business Combination, Opco entered into a revolving credit facility in the aggregate principal amount of up to $500 million. The Revolving Credit Facility, or other future debt agreements of us and Opco, will contain a number of restrictive covenants that may limit their ability to, among other things, incur additional indebtedness, make loans and advances, make capital expenditures, incur liens and sell assets. These restrictions may also limit the ability of us and Opco to pursue business opportunities that may arise in the future.

There is no guarantee that the public warrants will be in the money at the time they become exercisable, and they may expire worthless.

The exercise price for our warrants is $11.34 per share of Class A common stock. Pursuant to the Contribution Agreement, to the extent that any common stock dividend paid by the Company, when combined with other common stock dividends paid in the prior 365 days, exceeds 50 cents, it is categorized as an Extraordinary Dividend. Extraordinary Dividends reduce, penny for penny, the exercise price of the Company's warrants. There is no guarantee that the public warrants will be in the money following the time they become exercisable and prior to their expiration, and as such, the warrants may expire worthless.

We may amend the terms of the warrants in a manner that may be adverse to holders with the approval by the holders of at least 65% of the then outstanding public warrants. As a result, the exercise price of your warrants could be increased, the exercise period could be shortened and the number of shares of our Class A common stock purchasable upon exercise of a warrant could be decreased, all without your approval.

Our warrants were issued in registered form under a warrant agreement between Continental Stock Transfer & Trust Company, as warrant agent, and us. The warrant agreement provides that the terms of the warrants may be amended without the consent of any holder to cure any ambiguity or correct any defective provision but requires the approval by the holders of at least 65% of the then outstanding public warrants to make any change that adversely affects the interests of the registered holders. Accordingly, we may amend the terms of the public warrants in a manner adverse to a holder if holders of at least 65% of the then outstanding public warrants approve of such amendment. Although our ability to amend the terms of the public warrants with the consent of at least 65% of the then outstanding public warrants is unlimited, examples of such amendments could be amendments to, among other things, increase the exercise price of the warrants, shorten the exercise period or decrease the number of shares of our Class A common stock purchasable upon exercise of a warrant.

We may redeem unexpired warrants prior to their exercise at a time that is disadvantageous to warrant holders, thereby making their warrants worthless.

We have the ability to redeem outstanding warrants at any time after they become exercisable and prior to their expiration, at a price of $0.01 per warrant, provided that the last reported sales price of our Class A common stock equals or exceeds $18.00 per share for any 20 trading days within a 30-trading day period ending on the third trading day prior to the date we send the notice of redemption to the warrant holders. If and when the warrants become redeemable by us, we may exercise our redemption right even if we are unable to register or qualify the underlying securities for sale under all applicable state securities laws. Redemption of the outstanding warrants could force the warrant holders (i) to exercise their warrants and pay the exercise price therefor at a time when it may be disadvantageous for them to do so, (ii) to sell their warrants at the then-current market price when they might otherwise wish to hold their warrants or (iii) to accept the nominal redemption price which, at the time the outstanding warrants are called for redemption, is likely to be substantially less than the market value of their warrants. None of the private placement warrants will be redeemable by us so long as they are held by our Sponsor or its permitted transferees.

Warrants will become exercisable for our Class A common stock, which would increase the number of shares eligible for future resale in the public market and result in dilution to our stockholders.

We issued warrants to purchase 13,749,999 shares of Class A common stock as part of our IPO and concurrent with our IPO, we issued an aggregate of 7,500,000 private placement warrants to our Sponsor. Each warrant issued is exercisable to purchase one whole share of Class A common stock at $11.34 per whole share. Pursuant to the Contribution Agreement, to the extent that any common stock dividend paid by the Company, when combined with other common stock dividends paid in the prior 365 days, exceeds 50 cents, it is categorized as an Extraordinary Dividend. Extraordinary Dividends reduce, penny for penny, the exercise price of the Company's warrants. To the extent such warrants are exercised, additional shares of our Class A common stock will be issued, which will result in dilution to the then existing holders of our Class A common stock and increase the number of shares eligible for resale in the public market. Sales of substantial numbers of such shares in the public market could adversely affect the market price of our Class A common stock.

The private placement warrants are identical to the warrants sold as part of the units issued in our IPO, except that, so long as they are held by our Sponsor or its permitted transferees, (i) they will not be redeemable by us and (ii) they may be exercised by the holders on a cashless basis.

If additional stock consideration is issued to Royal pursuant to the earn-out provided for in the Contribution Agreement, it would increase the number of shares eligible for future resale in the public market and result in dilution to our stockholders.

Pursuant to the Contribution Agreement, Royal is entitled to receive earn-out consideration to be paid in the form of OpCo Common Units (and a corresponding number of shares of Class C common stock) if the 30-day volume-weighted average price ("30-Day VWAP") of the Class A common stock equals or exceeds certain hurdles set forth in the Contribution Agreement. Royal can potentially receive up to an additional 20.0 million OpCo Common Units as a part of the earn-out consideration. Royal is also entitled to the earn-out consideration described above in connection with certain liquidity events of the Company, including a merger or sale of all or substantially all of the Company's assets, if the consideration paid to holders of the Class A common stock in connection with such liquidity event is greater than any of the 30-Day VWAP hurdles. Because any OpCo Common Units issued pursuant to the earn-out are redeemable on a one-for-one basis for shares of Class A common stock at the option of the Contributors, the issuance of additional stock consideration pursuant to the earn-out will result in dilution to the then existing holders of our Class A common stock and increase the number of shares eligible for resale in the public market. Sales of substantial numbers of such shares in the public market could adversely affect the market price of our Class A common stock.

A significant portion of our total outstanding shares may be sold into the market in the near future. This could cause the market price of our Class A common stock to drop significantly, even if our business is doing well.

Sales of a substantial number of shares of Class A common stock in the public market could occur at any time. These sales, or the perception in the market that the holders of a large number of shares intend to sell shares, could reduce the market price of our Class A common stock. After the Business Combination, our Sponsor owned approximately 8.0% of our Class A common stock. Pursuant to the terms of a letter agreement entered into at the time of the IPO, the founder shares (which converted into shares of Class A common stock at the closing of the Business Combination) held by our Sponsor became freely tradable one year after the closing of the Business Combination.

Additionally, the Contributors have the ability to redeem or exchange their common units for shares of Class A common stock on a one-to-one basis, provided that the ratio of the limited partner's redeemed common units to the number of common units beneficially held by such limited partner remains equal to that of the Blackstone Funds. If the Contributors redeem or exchange all of their common units for shares of Class A common stock, and assuming no earn-out consideration is paid prior to such time and we do not otherwise issue shares of Class A common stock, the Contributors will own approximately 47% of our Class A common stock.

In connection with the closing of our IPO, we entered into a registration rights agreement with our Sponsor providing for registration rights to it. In addition, in connection with the closing of the Business Combination, we entered into a registration rights agreement with Royal LP and the Contributors, pursuant to which we filed a registration statement registering the shares of Class A common stock held by them for resale within 30 days following the closing of the Business Combination.

If securities or industry analysts do not publish or cease publishing research or reports about us, our business, or our market, or if they change their recommendations regarding our Class A common stock adversely, the price and trading volume of our Class A common stock could decline.

The trading market for our Class A common stock is influenced by the research and reports that industry or securities analysts may publish about us, our business, our market, or our competitors. If any of the analysts who cover us change their recommendation regarding our stock adversely, or provide more favorable relative recommendations about our competitors, the price of our Class A common stock could potentially decline. If any analyst who may cover us were to cease their coverage or fail to regularly publish reports on us, we could lose visibility in the financial markets, which could cause our stock price or trading volume to decline.

Blackstone, Royal and the Contributors have significant influence over us.

Blackstone, Royal and the Contributors beneficially own common stock representing approximately 47% of our outstanding voting power. As long as our Sponsor and the Contributors own or control a significant percentage of our outstanding voting power, subject to the terms of the Shareholders' Agreement, they will have the ability to influence certain corporate actions requiring stockholder approval. In certain circumstances, Royal and the Contributors may transfer their equity interests in us and/or OpCo without the consent of the public stockholders or our Board of Directors, and the transferee would have significant influence over us.

In addition, under the Shareholders' Agreement, Blackstone is entitled to designate six directors for nomination by our Board of Directors for election as directors by our stockholders, representing a majority of our Board of Directors, and has certain other rights with respect to our Board of Directors composition, including consent rights with respect to individuals nominated by our Board of Directors for election as independent directors, and our governance.

Provisions in the Second A&R Charter may prevent or delay an acquisition of us, which could decrease the trading price of our common stock, or otherwise may make it more difficult for certain provisions of the Second A&R Charter to be amended.

The Second A&R Charter contains provisions that are intended to deter coercive takeover practices and inadequate takeover bids and to encourage prospective acquirers to negotiate with our Board of Directors rather than to attempt a hostile takeover. These provisions include:

- a board of directors that is divided into three classes with staggered terms;
- the right of our board of directors to issue preferred stock without stockholder approval;
- restrictions on the right of stockholders to remove directors without cause; and
- restrictions on the right of stockholders to call special meetings of stockholders.

These provisions apply even if the offer may be considered beneficial by some stockholders and could delay or prevent an acquisition that our Board of Directors determines is not in our and our stockholders' best interests.

In addition, the Second A&R Charter requires the affirmative vote of the holders of at least 75% of the voting power of all outstanding shares of capital stock of Falcon to amend, repeal or adopt certain provisions of the Second A&R Charter relating to the Board of Directors, the bylaws, meetings of stockholders, indemnification of officers and directors, waiver of corporate opportunities, exclusive forum, amendments to the Second A&R Charter and Delaware's business combinations statute. This requirement will make it more difficult for these provisions of the Second A&R Charter, which include the provisions intended to deter coercive takeover practices and inadequate takeover bids, to be amended.

The Second A&R Charter designates the Court of Chancery of the State of Delaware (or, if the Court of Chancery of the State of Delaware does not have jurisdiction, any state or the federal court sitting in the State of Delaware with jurisdiction over the matter) as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit the ability of our stockholders to obtain a favorable judicial forum for disputes with us or with directors, officers or employees of us and may discourage stockholders from bringing such claims.

The Second A&R Charter designates the Court of Chancery of the State of Delaware (or, if the Court of Chancery of the State of Delaware does not have jurisdiction, any state or the federal court sitting in the State of Delaware with jurisdiction over the matter) as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit the ability of our stockholders to obtain a favorable judicial forum for disputes with us or with directors, officers or employees of us and may discourage stockholders from bringing such claims. Alternatively, if a court were to find these provisions of the Second A&R Charter inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition, and results of operations.

Changes in laws or regulations, or a failure to comply with any laws and regulations, may adversely affect our business, investments and results of operations.

We are subject to laws, regulations and rules enacted by national, regional and local governments and NASDAQ. In particular, we are required to comply with certain SEC, NASDAQ, and other legal or regulatory requirements. Compliance with, and monitoring of, applicable laws, regulations and rules may be difficult, time consuming and costly. Those laws, regulations and rules and their interpretation and application may also change from time to time and those changes could have a material adverse effect on our business, investments and results of operations. In addition, a failure to comply with applicable laws, regulations and rules, as interpreted and applied, could have a material adverse effect on our business and results of operations.

The 2017 tax law could adversely affect our business and financial condition.

On December 22, 2017, President Trump signed into law the final version of the tax reform bill commonly known as the "Tax Cuts and Jobs Act," (the "TCJA"), that significantly amends the Internal Revenue Code of 1986, as amended (the "Code"). The TCJA, among other things, contains significant changes to corporate taxation, including a reduction of the corporate income tax rate, a partial limitation on the deductibility of business interest expense, a limitation of the deduction for net operating loss carryforwards to 80% of current year taxable income, an indefinite net operating loss carryforward, immediate deductions for certain new investments instead of deductions for depreciation expense over time, and the modification or repeal of many business deductions and credits. We continue to examine the impact this legislation may have on our business. Notwithstanding the reduction in the corporate income tax rate, the overall impact of the TCJA is uncertain and our business and financial condition could be adversely affected. The impact of this law on holders of our Class A common stock is also uncertain and could be adverse.

The JOBS Act permits "emerging growth companies" like us to take advantage of certain exemptions from various reporting requirements applicable to other public companies that are not emerging growth companies.

We qualify as an "emerging growth company" as defined in Section 2(a)(19) of the Securities Act, as modified by the Jumpstart Our Business Startups Act of 2012 (the "JOBS Act"). As such, we take advantage of certain exemptions from various reporting requirements applicable to other public companies that are not emerging growth companies for as long as we continue to be an emerging growth company, including (i) the exemption from the auditor attestation requirements with respect to internal control over financial reporting under Section 404 of the Sarbanes-Oxley Act, (ii) the exemptions from say-on-pay, say-on-frequency and say-on-golden parachute voting requirements and (iii) reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements. As a result, our stockholders may not have access to certain information they deem important. We will remain an emerging growth company until the earliest of (i) the last day of the fiscal year (a) following July 26, 2022, the fifth anniversary of our IPO, (b) in which we have total annual gross revenue of at least $1.07 billion or (c) in which we are deemed to be a large accelerated filer, which means the market value of our Class A common stock that is held by non-affiliates exceeds $700 million as measured on the last business day of our most recently completed second fiscal quarter, or (ii) the date on which we have issued more than $1.0 billion in non-convertible debt during the prior three-year period.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the exemption from complying with new or revised accounting standards provided in Section 7(a)(2)(B) of the Securities Act as long as we are an emerging growth company. An emerging growth company can, therefore, delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. The JOBS Act provides that a company can elect to opt out of the extended transition period and comply with the requirements that apply to non-emerging growth companies, but any such election to opt out is irrevocable. We have elected not to opt out of such extended transition period, which means that when a standard is issued or revised and it has different application dates for public or private companies, we, as an emerging growth company, can adopt the new or revised standard at the time private companies adopt the new or revised standard. This may make comparison of our financial statements with another public company which is neither an emerging growth company nor an emerging growth company which has opted out of using the extended transition period difficult or impossible because of the potential differences in accounting standards used.

We cannot predict if investors will find our Class A common stock less attractive because we will rely on these exemptions. If some investors find our Class A common stock less attractive as a result, there may be a less active trading market for our Class A common stock and our stock price may be more volatile.

If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential shareholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a publicly traded company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under

Section 404 of the Sarbanes-Oxley Act of 2002. For example, Section 404 requires us, among other things, to annually review and report on, and would require our independent registered public accounting firm to attest to, the effectiveness of our internal controls over financial reporting once we are no longer exempt under the JOBS Act. Any failure to maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our Class A common stock.

Non-U.S. holders may be subject to U.S. federal income tax with respect to gain on disposition of their Class A common stock and warrants.

We believe that we are a U.S. real property holding corporation ("USRPHC"), following our Business Combination. As a result, Non-U.S. holders that own (or are treated as owning under constructive ownership rules) more than a specified amount of our Class A common stock or warrants during a specified time period may be subject to U.S. federal income tax on a sale, exchange, or other disposition of such Class A common stock or warrants and may be required to file a U.S. federal income tax return. If you are a Non-U.S. holder, we urge you to consult your tax advisors regarding the tax consequences of such treatment.

Risks Related to Our Operators

The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies, oilfield services or personnel may restrict the operations of our operators.

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies and personnel. When shortages occur, the costs and delivery times of rigs, equipment and supplies increase and demand for, and wage rates of, qualified drilling rig crews also rise with increases in demand. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. In accordance with customary industry practice, our operators will rely on independent third-party service providers to provide most of the services necessary to drill new wells. If they are unable to secure a sufficient number of drilling rigs at reasonable costs, our financial condition and results of operations could suffer. In addition, they may not have long-term contracts securing the use of their rigs, and the operator of those rigs may choose to cease providing services to them. Shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, frac crews, tubulars, fracking and completion services and production equipment could delay or restrict our operators' exploration and development operations, which in turn could adversely affect our financial condition and results of operations.

Restrictions on our operators' ability to obtain water may have an adverse effect on our financial condition and results of operations.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. During the last several years, Texas has experienced extreme drought conditions. As a result of this severe drought, some local water districts have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supply. If our operators are unable to obtain water to use in their operations from local sources, or our operators are unable to effectively utilize flowback water, they may be unable to economically drill for or produce oil and natural gas, which could have an adverse effect on our financial condition and results of operations.

The results of our operators' exploratory drilling in shale plays will be subject to risks associated with drilling and completion techniques and drilling results may not meet our expectations for reserves or production.

The drilling by our operators involves a number of risks, including the risk of landing their well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running their casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that they will face while completing wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. Furthermore, certain of the new techniques our operators may adopt, such as infill drilling and multi-well pad drilling, may cause irregularities or interruptions in production due to, in the case of infill drilling, offset wells being shut in and, in the case of multi-well pad drilling, the time required to drill and complete multiple wells before any such wells begin producing. The results of drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas often have limited or no production history and consequently we will be less able to predict future drilling results in these areas.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our operators' drilling results are less than anticipated or they are unable to execute their drilling program because of capital constraints, lease expirations, access to gathering systems, and/or declines in natural gas and oil prices, the return on our investment in these areas may not be as attractive as we anticipate.

The marketability of oil and natural gas production is dependent upon transportation and other facilities, certain of which neither we nor our operators' control. If these facilities are unavailable, our operators' operations could be interrupted and our financial condition and results of operations could be adversely affected.

The marketability of our operators' oil and natural gas production will depend in part upon the availability, proximity and capacity of transportation facilities, including gathering systems, trucks and pipelines, owned by third parties. Neither we nor our operators control these third-party transportation facilities and our operators' access to them may be limited or denied. Insufficient production from the wells on the acreage underlying our royalties to support the construction of pipeline facilities by our purchasers or a significant disruption in the availability of third-party transportation facilities or other production facilities could adversely impact our operators' ability to deliver to market or produce oil and natural gas and thereby cause a significant interruption in our operators' operations. If they are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, they may be required to shut in or curtail production. In addition, the amount of oil and natural gas that can be produced and sold may be subject to curtailment in certain other circumstances outside of our control, such as pipeline interruptions due to maintenance, excessive pressure, ability of downstream processing facilities to accept unprocessed gas, physical damage to the gathering or transportation system or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we and our operators are provided with limited, if any, notice as to when these circumstances will arise and their duration. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from the acreage underlying our royalty fields, could adversely affect our financial condition and results of operations.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that may adversely affect our business, financial condition and results of operations.

Our operators' drilling activities will be subject to many risks. For example, we will not be able to assure you that wells drilled by our operators will be productive. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then realized prices after deducting drilling, operating and other costs. The seismic data and other technologies used do not provide conclusive knowledge prior to drilling a well that oil or natural gas is present or that it can be produced economically. The costs of exploration, exploitation and development activities are subject to numerous uncertainties beyond our control and increases in those costs can adversely affect the economics of a project. Further, our operators' drilling and producing operations may be curtailed, delayed, canceled or otherwise negatively impacted as a result of other factors, including:

- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delivery delays of equipment and services;
- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties. In the event that planned operations, including the drilling of development wells, are delayed or cancelled, or existing wells or development wells have lower than anticipated production due to one or more of the factors above or for any other reason, our financial condition and results of operations may be adversely affected.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Our executive offices are located at 510 Madison Avenue, 8th Floor, New York, NY 10022. We have additional leased office space in Philadelphia, PA and Houston, TX. We believe that these facilities are adequate for our current operations.

ITEM 3. LEGAL PROCEEDINGS

To the knowledge of our management, there is no material litigation, arbitration or governmental proceeding currently pending against us or any members of our management team in their capacity as such.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON UNITS, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information

Our units commenced public trading on July 21, 2017, and our Class A Common Stock and warrants commenced separate trading on August 15, 2017. Prior to the separation of our units on August 15, 2017, there was no public market for our Class A Common Stock. Prior to the Closing of the Transactions on August 23, 2018, our Class A Common Stock, warrants and units were each listed on the NASDAQ Capital Market under the symbols OSPR, OSPRW and OSPRU, respectively.

Our Class A Common Stock and warrants are currently listed on the Nasdaq Capital Market under the symbols "FLMN" and "FLMNW," respectively.

We had approximately 20 registered stockholders of record of our Class A Common Stock as of March 6, 2020. This number does not include owners or stockholders who beneficially own our shares through a broker or other entity who may hold shares in "street name". There is no public market for our Class C Common Stock. As of March 6, 2020, we had 7 holders of record of our Class C Common Stock.

Dividend Policy

Cash dividends are made to the Class A Common Stock stockholders of record on the applicable record date, within 60 days after the end of each quarter. Available cash for each quarter is determined by the board of directors of the Company following the end of such quarter. Available cash for each quarter generally equals Adjusted EBITDA reduced for cash needs for debt service and other contractual obligations and fixed charges that the board of directors of our Company deems necessary or appropriate, if any.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

None.

Securities Authorized for Issuance under Equity Compensation Plans

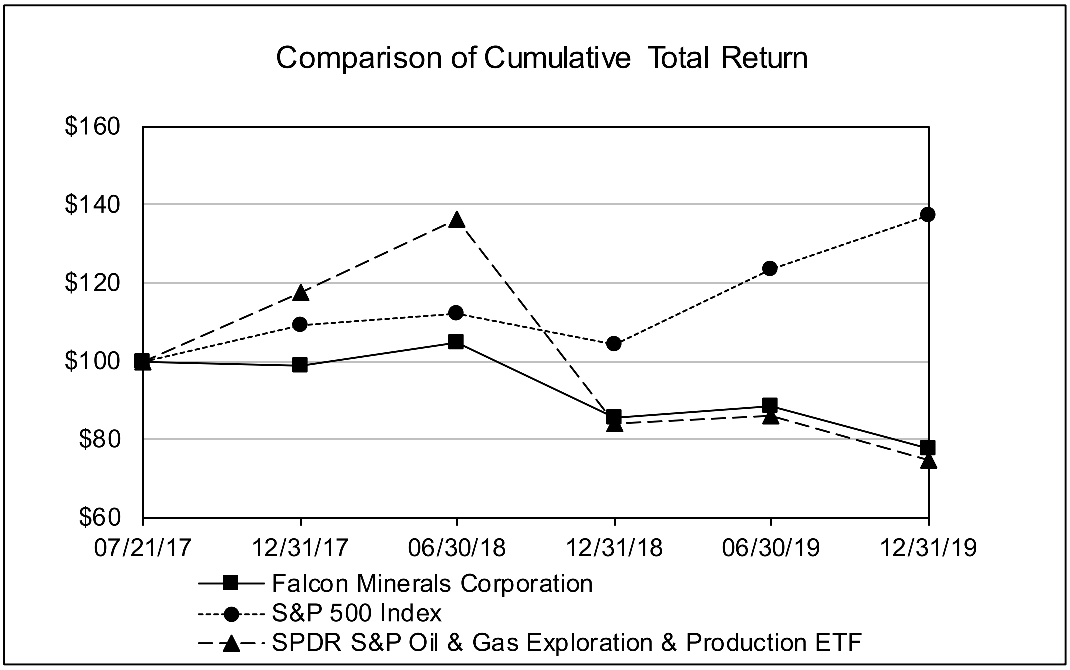
The following table sets forth information as of December 31, 2019 with respect to equity compensation plans under which shares of our common stock are authorized for issuance:

	(a) Number of Shares to be Issued Upon Exercise of Outstanding Stock Options and Rights	(b) Weighted Average Exercise Price Of Outstanding Stock Options and Rights	(c) Number of Shares Remaining Available For Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Plan Category			
Equity compensation plans approved by stockholders:			
Long Term Incentive Plan (1)	1,893,717	-	6,381,060
Equity compensation plans not approved by stockholders:	-	-	-
Total	1,893,717	-	6,381,060

(1) The Falcon Minerals Corporation 2018 Long-Term Incentive Plan (the "Plan") was adopted by our Board of Directors and our stockholders in connection with the Closing of the Transactions. The Plan contemplates the issuance or delivery of up to 8,600,000 shares of common stock to satisfy awards under the Plan.

Stockholder Performance Graph

The performance graph below compares the cumulative total returns of our Class A Common Stock over the period from July 21, 2017 through December 31, 2019 with the cumulative total returns for the same period for the Standard and Poor's ("S&P") 500 Index and the SPDR S&P Oil & Gas Exploration & Production ETF ("XOP"). XOP is a weighted composite of 69 oil and gas exploration and productions companies. The cumulative total stockholder return assumes that $100 was invested, including reinvestment of dividends, if any, in our Class A Common Stock on July 21, 2017, and in the S&P 500 Index and XOP on the same date. The results shown in the graph below are not necessarily indicative of future performance.



ITEM 6. SELECTED FINANCIAL DATA

The following tables set forth our selected historical consolidated financial data for each of the last five years. The consolidated financial data presented as of and for the years ended December 31, 2019, 2018, 2017, 2016 and 2015 are derived from our audited historical consolidated financial statements. Our financial statements have been prepared in accordance with GAAP. The following table should be read in conjunction with our consolidated financial statements and notes thereto included elsewhere in this Annual Report (in thousands, except operating data and per unit amounts).

	Year Ended December 31,				
	2019	2018	2017	2016	2015
Revenues:					
Oil and gas sales	$ 68,463	$ 98,655	$ 95,972	$ 70,964	$ 106,492
Gain (loss) on hedging activities	-	(1,456)	1,791	(843)	-
Total revenue	68,463	97,199	97,763	70,121	106,492
Operating expenses:					
Production and ad valorem taxes	4,262	5,143	5,242	4,531	6,352
Marketing and transportation	2,396	2,368	6,505	6,605	7,915
Amortization of royalty interests in oil and natural gas properties	12,737	16,962	33,837	35,840	45,676
General, administrative and other	11,912	9,544	8,213	6,114	11,685
Total operating expenses	31,307	34,017	53,797	53,090	71,628
Operating income	37,156	63,182	43,966	17,031	34,864
Other income (expense):					
Gain on the sale of assets	-	41,382	31,441	-	-
Other income	165	46	34	823	436
Interest expense	(2,489)	(2,350)	(2,746)	(3,096)	(5,300)
Total other income (expense)	(2,324)	39,078	28,729	(2,273)	(4,864)
Income before income taxes	34,832	102,260	72,695	14,758	30,000
Provision for income taxes	3,918	3,292	-	-	-
Income from continuing operations	30,914	98,968	72,695	14,758	30,000
Income (loss) from discontinued operations	-	2,139	2,978	22	(462)
Net income	30,914	101,107	75,673	14,780	29,538
Net income attributable to non-controlling interests	(16,564)	(10,982)	(155)	(69)	(97)
Net income attributable to common shareholders/unitholders	$ 14,350	$ 90,125	$ 75,518	$ 14,711	$ 29,441

	Year Ended December 31,				
	2019	2018	2017	2016	2015
Earnings per share:					
Common shares, basic and diluted	$ 0.31	$ 0.20	N/A	N/A	N/A
Cash Dividends Declared Per Share:	$ 0.595	$ 0.295	N/A	N/A	N/A
Statement of Cash Flow Data:					
Net cash flows provided by (used in):					
Operating activities	$ 55,229	$ 77,886	$ 80,791	$ 51,279	$ 88,197
Investing activities	(23,353)	122,312	83,048	(5,260)	(8,100)
Financing activities	(36,650)	(203,378)	(161,390)	(76,225)	(76,563)
Other Financial Data:					
Adjusted EBITDA (1)	$ 52,607	$ 80,190	$ 77,837	$ 53,625	$ 80,976
Balance Sheet Data (at period end):					
Cash and cash equivalents	$ 2,543	$ 7,317	$ 8,345	$ 5,536	$ 36,849
Total assets	290,205	291,235	352,718	435,897	498,374
Long-term debt (including current portion)	42,500	21,000	57,000	57,683	108,000
Total liabilities	45,179	21,521	63,561	62,023	115,758
Shareholder's equity / Partners' capital	245,026	269,714	289,157	373,874	382,616
Production Data					
Oil (Bbls)	879,288	1,237,813	1,582,322	1,474,218	1,919,955
Natural gas (BOE)	598,019	686,279	760,982	690,613	892,977
Natural gas liquids (Bbls)	296,813	293,086	542,706	511,337	650,599
Combined volumes (BOE)	1,774,120	2,217,178	2,886,010	2,676,168	3,463,531
Average daily combined volume (BOE/d)	4,861	6,074	7,907	7,332	9,489
% Oil	50%	56%	55%	55%	55%
Average sales prices:					
Oil (Bbls)	$ 59.85	$ 67.14	$ 50.54	$ 39.96	$ 46.12
Natural gas (Mcf)	$ 2.62	$ 3.10	$ 2.81	$ 2.19	$ 2.33
Natural gas liquids (Bbls)	$ 15.45	$ 25.62	$ 20.63	$ 12.04	$ 13.07
Combined per (BOE)	$ 37.54	$ 46.63	$ 35.67	$ 27.69	$ 31.19
Average Costs ($/BOE):					
Production and ad valorem taxes	$ 2.40	$ 2.32	$ 1.82	$ 1.69	$ 1.83
Gathering and transportation expense	$ 1.35	$ 1.07	$ 2.25	$ 2.47	$ 2.29
General and administrative	$ 6.71	$ 4.30	$ 2.85	$ 2.28	$ 3.37
Interest expense, net	$ 1.40	$ 1.06	$ 0.95	$ 1.16	$ 1.53
Depletion	$ 7.18	$ 7.65	$ 11.72	$ 13.39	$ 13.19

(1) Adjusted EBITDA is a non-GAAP financial measure. For additional information regarding our calculation of Adjusted EBITDA as well as a reconciliation of net income to Adjusted EBITDA, please see Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview of Our Results of Operations—Adjusted EBITDA" below.

Items Affecting Comparability of Our Financial Condition and Results of Operations

Future financial data of Falcon attributable to us may not be comparable to the historical results of our operations for the periods presented due to the following reasons:

Acquisition of the Royal Entities

Because Royal has effective control of the combined company after the Transactions through its majority voting interests in both the Company and, accordingly, OpCo, the Transactions were accounted for as a reverse recapitalization. Although the Company was the legal acquirer, Royal was the accounting acquirer. As a result, the reports filed by the Company subsequent to the Transactions are prepared "as if" Royal is the predecessor and legal successor to the Company. The historical operations of Royal are deemed to be those of the Company. Thus, the financial information included above reflect (i) the historical operating results of Royal prior to the Transactions; (ii) the combined results of the Company, OpCo and Royal following the Transactions; (iii) the assets, liabilities and partners' capital of Royal at their historical costs; and (iv) the Company's equity and earnings per share presented for the period from the Closing Date of the Business Combination.

The RNR assets, liabilities and operations are considered discontinued operations prior to the Closing Date of the Transactions. Therefore, the carrying amounts of the major classes of assets and liabilities of the discontinued operations are classified as held for sale and are presented separately in the consolidated balance sheets. In addition, the results of operations of RNR for the periods presented have been included in discontinued operations in the consolidated statements of operations.

Income Taxes

Royal was historically treated as a partnership for federal income tax purposes, with each partner being separately taxed on its share of taxable income; therefore, there is no federal income tax expense reflected in Royal's financial statements for any period prior to the Transactions on August 23, 2018. Falcon is a C-corporation under the Internal Revenue Code. As a result, the Company is subject to federal income taxes and recognizes deferred tax assets and liabilities based on the differences between the financial statement carrying value and tax basis of the assets acquired in the Transactions.

Public Company Expenses

We incur direct, incremental G&A expense as a result of being a publicly traded company, including, but not limited to, cost associated with preparing annual and quarterly reports to stockholders, tax return preparation, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs, independent director compensation and other similar costs. These direct, incremental G&A expenses related to being a public company are expected to increase in future periods, given the change in the Company's capital structure upon the closing of the Transactions.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion of our historical performance and financial condition together with Part II, Item 6. "Selected Financial Data," the description of the business appearing in Part I, Item 1. "Business," and the consolidated financial statements and the related notes in Part II, Item 8. of this Annual Report. This discussion may contain forward-looking statements that are based on the views and beliefs of our management, as well as assumptions and estimates made by our management. Actual results could differ materially from such forward-looking statements as a result of various risk factors, including those that may not be in the control of management. Factors that could cause or contribute to these differences include those discussed below and elsewhere in this report, particularly in Part I, Item 1A. "Risk Factors" and under "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We were formed to own and acquire Royalties in oil and natural gas properties in North America, substantially all of which are located in the Eagle Ford Shale. These Royalties entitle the holder to a portion of the production of oil and natural gas from the underlying acreage at the sales price received by the operator, net of any applicable post-production expenses and taxes. The holder of these interests has no obligation to fund exploration and development costs, lease operating expenses or plugging and abandonment costs at the end of a well's productive life, which we believe results in low breakeven costs.

We own Royalties that entitle us to a portion of the production of oil, natural gas and NGLs from the underlying acreage at the sales price received by the operator, net of production expenses and taxes. We have no obligation to fund finding and development costs or pay capital expenditures such as plugging and abandonment costs. We have minimal allocated lease operating expenses. As such, we have historically operated with high cash margins, converting a large percentage of revenue to free cash flow, the majority of which can be distributed to our stockholders.

Recent Developments

None.

Factors Impacting the Comparability of Our Financial Results

Public Company Expenses. We incur direct G&A expense as a result of being a publicly traded company, including, but not limited to, costs associated with hiring new personnel, implementation of compensation programs that are competitive with our public company peer group, annual and quarterly reports to stockholders, tax return preparation, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs, independent director compensation and other similar costs. These direct G&A expenses are not included in Royal's historical financial results of operations prior to the Transactions.

Income Taxes. Prior to the Transactions, Royal was treated as a partnership for U.S. federal income tax purposes and for purposes of certain state and local income taxes. Royal was not subject to U.S. federal income taxes. However, Royal was subject to the Texas margin tax. Any taxable income or loss generated by Royal was passed through to and included in the taxable income or loss of its members. We are a corporation and are subject to U.S. federal income taxes, in addition to state and local income taxes with respect to our allocable share of any taxable income or loss of OpCo, as well as any stand-alone income or loss generated by us.

Sources of Our Revenue

Our revenues were derived from royalty payments we received from our operators based on the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from natural gas during processing. As of December 31, 2019, our Royalties represented the right to receive an average of 1.32% from the producing wells on the underlying acreage at the sales price received by our operators net of any applicable post-production expenses and taxes. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. Oil, natural gas liquids and natural gas prices have historically been volatile, and at December 31, 2019, we did not hedge any of our exposure to changes in commodity prices. During the twelve months ended December 31, 2018, West Texas Intermediate posted prices that ranged from \$49.98 to \$70.76 per Bbl and the Henry Hub settlement price of natural gas ranged from \$2.64 to \$4.72 per MMBtu. During the twelve months ended December 31, 2019, the West Texas Intermediate posted prices that ranged from \$51.55 to \$63.87 per Bbl for crude oil and the Henry Hub settlement price of natural gas ranged from \$2.14 to \$3.64 per MMBtu for natural gas.

The following table presents the breakdown of our revenue for the following periods:

	Year Ended December 31,		
	2019	2018	2017
Royalty Income:			
Oil sales	77%	81%	77%
Natural gas sales	14%	12%	12%
Natural gas liquids sales	7%	7%	11%
Lease bonus	2%	0%	0%
Total	100%	100%	100%

Commodity prices are inherently volatile, and changes in such prices have historically had an impact on our revenue. Lower prices may not only decrease our revenues, but also potentially the amount of oil and natural gas that our operators can produce economically. Lower oil and natural gas prices may also result in a reduction in the borrowing base under our credit agreement, which may be redetermined at the discretion of our lenders.

The following table sets forth the average realized prices for oil, natural gas and natural gas liquids for the years ended December 31, 2019, 2018 and 2017:

	Year Ended December 31,		
	2019	2018	2017
Oil (Bbls)	$ 59.85	$ 67.14	$ 50.54
Natural gas (Mcf)	$ 2.62	$ 3.10	$ 2.81
Natural gas liquids (Bbls)	$ 15.45	$ 25.62	$ 20.63

Principal Components of Our Cost Structure

Production and Ad Valorem Taxes

Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at fixed rates established by federal, state and local taxing authorities. Where available, we have historically benefited from tax credits and exemptions in our various taxing jurisdictions. We also directly paid ad valorem taxes in the counties where our production was located. Ad valorem taxes were generally based on the state government's appraisal of our oil and natural gas properties.

Marketing and Transportation

Marketing and transportation expenses include the costs to process and transport our production to applicable sales points. Generally, the terms of the lease governing the development of our properties permit the operator to pass through these expenses to us by deducting a pro rata portion of such expenses from our production revenues.

Amortization

Our Royalties are recorded at cost and capitalized as tangible assets. Acquisition costs related to proved properties are amortized on a units of production basis over the life of the proved reserves.

General and Administrative

General and administrative expenses are costs not directly associated with the production of oil, natural gas and NGLs and include the cost of executives and employees and related benefits (including stock-based compensation expenses), office expenses and fees for professional services. Since the completion of the Transactions in August 2018, we incurred incremental G&A expenses relating to expenses associated with SEC reporting requirements, including annual and quarterly reports to shareholders, tax return preparation and dividend expenses, Sarbanes-Oxley Act compliance expenses, expenses associated with listing our securities, independent auditor fees, legal expenses and investor relations expenses. These incremental G&A expenses are not reflected in the historical financial statements.

Historically these are costs incurred for overhead, including the allocation of a portion of the historical cost of management, operating and administrative services provided under a master services agreement (the "MSA") between Royal and Riverbend Oil & Gas, L.L.C. ("Riverbend"), which owned a portion of Royal through an affiliate and whose employees historically managed Royal's predecessor and Royal, audit and other fees for professional services and legal compliance. On the Closing Date, Royal assigned to the Company its rights and responsibilities under the existing MSA. Riverbend performed substantially the same services for the Company as those Riverbend performed for Royal prior to the Closing Date for the duration of the term of the MSA, which expired on December 10, 2018. The Company has assumed the day-to-day management of the Company since the expiration of the MSA with Riverbend.

Interest Expense

We finance a portion of our working capital requirements and acquisitions with borrowings under our credit facility. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to the lenders under our credit facility in interest expense on our statement of operations. Please read "—Liquidity and Capital Resources—Indebtedness" for further details of our credit facility.

Borrowings under Royal's first lien credit facility and RNR credit facility historically served to fund distributions to its equity owners. As a result, Royal incurred substantial interest expense that was affected by both fluctuations in interest rates and Royal's financing decisions. These facilities are no longer our obligations after the Closing.

Income Tax Expense

Income taxes reflect the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when assets are recovered or settled. Deferred income taxes are also recognized for tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying current tax rates to the differences between financial statement and income tax reporting. In assessing the realization of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. We consider the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, projected future taxable income and tax planning strategies in making this assessment. We will continue to evaluate whether the valuation allowance is needed in future reporting periods. We are subject to taxation in many jurisdictions, and the calculation of our income tax liabilities involves dealing with uncertainties in the application of complex income tax laws and regulations in various taxing jurisdictions. We recognize certain income tax positions that meet a more-likely-than not recognition threshold. If we ultimately determine that the payment of these liabilities will be unnecessary, we will reverse the liability and recognize an income tax benefit during the period in which we determine the liability no longer applies.

Royal was historically treated as a partnership for federal income tax purposes, with each partner being separately taxed on its share of taxable income; therefore, there is no federal income tax expense reflected in Royal's financial statements for any period prior to the Closing of the Transactions on August 23, 2018.

Overview of Our Results of Operations

Basis of Presentation

The following financial information include information regarding Royal Resources L.P. as Falcon's predecessor entity, which includes certain interests in subsidiary companies which were not acquired by the Company in the Transactions. The Royal Resources L.P. subsidiaries that were contributed in the Transactions are VickiCristina, LP, DGK ORRI Company, L.P., Noble EF DLG LP, Noble EF LP and Noble Marcellus LP. The interests in Riverbend Natural Resources, L.P ("RNR") and KGD ORRI, L.P. were not contributed in the Transactions. Thus, the financial results included in this Annual Report reflect (i) the historical operating results of Royal prior to the Transactions; (ii) the combined results of the Company and Royal following the Transactions; (iii) the assets, liabilities and partners' capital of Royal at their historical costs; (iv) RNR's financial results for all periods presented have been reclassified to discontinued operations; and (iv) the Company's equity and earnings per share presented for all periods following the Transactions.

The following table summarizes our revenue and expenses and production data for the periods indicated (in thousands, except production data).

	Year Ended December 31,		
	2019	**2018**	**2017**
Revenues:			
Oil and gas sales	$ 68,463	$ 98,655	$ 95,972
Gain (loss) on hedging activities	-	(1,456)	1,791
Total revenue	68,463	97,199	97,763
Operating expenses:			
Production and ad valorem taxes	4,262	5,143	5,242
Marketing and transportation	2,396	2,368	6,505
Amortization of royalty interests in oil and natural gas properties	12,737	16,962	33,837
General, administrative and other	11,912	9,544	8,213
Total operating expenses	31,307	34,017	53,797
Operating income	37,156	63,182	43,966
Other income (expense):			
Gain on the sale of assets	-	41,382	31,441
Other income	165	46	34
Interest expense	(2,489)	(2,350)	(2,746)
Total other income (expense)	(2,324)	39,078	28,729
Income before income taxes	34,832	102,260	72,695
Provision for income taxes	3,918	3,292	-
Income from continuing operations	30,914	98,968	72,695
Income (loss) from discontinued operations	-	2,139	2,978
Net income	30,914	101,107	75,673
Net income attributable to non-controlling interests	(16,564)	(10,982)	(155)
Net income attributable to common shareholders/unitholders	$ 14,350	$ 90,125	$ 75,518
Other Financial Data:			
Adjusted EBITDA [(1)]	$ 52,607	$ 80,190	$ 77,837

(1) Adjusted EBITDA is a non-GAAP financial measure. For additional information regarding our calculation of Adjusted EBITDA as well as a reconciliation of net income to Adjusted EBITDA, please see “Overview of Our Results of Operations—Adjusted EBITDA” below.

	For the Year Ended December 31,		
	2019	2018	2017
Production Data:			
Oil (Bbls)	879,288	1,237,813	1,582,322
Natural gas (BOE)	598,019	686,279	760,982
Natural gas liquids (Bbls)	296,813	293,086	542,706
Combined volumes (BOE)	1,774,120	2,217,178	2,886,010
Average daily combined volume (BOE/d)	4,861	6,074	7,907
% Oil	50%	56%	55%
Average sales prices:			
Oil (Bbls)	$ 59.85	$ 67.14	$ 50.54
Natural gas (Mcf)	$ 2.62	$ 3.10	$ 2.81
Natural gas liquids (Bbls)	$ 15.45	$ 25.62	$ 20.63
Combined per (BOE)	$ 37.54	$ 46.63	$ 35.67
Average Costs ($/BOE):			
Production and ad valorem taxes	$ 2.40	$ 2.32	$ 1.82
Gathering and transportation expense	$ 1.35	$ 1.07	$ 2.25
General and administrative	$ 6.71	$ 4.30	$ 2.85
Interest expense, net	$ 1.40	$ 1.06	$ 0.95
Depletion	$ 7.18	$ 7.65	$ 11.72

Comparison of Year Ended December 31, 2019 to Year Ended December 31, 2018

Oil and Gas Revenues

Oil and gas revenues decreased $30.2 million, or 31%, to $68.5 million for the year ended December 31, 2019, from $98.7 million for the year ended December 31, 2018. The decrease in oil and gas revenues was attributable to a decrease in oil and natural gas production in addition to a decrease in realized oil and natural gas prices. In March 2018, six wells on certain oil and gas properties located in the Eagle Ford shale, which the Company has a significant interest in, came on line and the subsequent natural decline in production after they came on line through December 31, 2019 was the main cause for the decrease in oil and natural gas production. The decrease in revenue was partially offset by a $1.5 million increase in lease bonus revenue in 2019. We received an average price of $59.85 per Bbl of oil and $2.62 per Mcf of gas sold during the year ended December 31, 2019 compared to $67.14 per Bbl of oil and $3.10 per Mcf of gas sold during the year ended December 31, 2018.

Production and Ad Valorem Taxes

Production and ad valorem taxes decreased $0.9 million, or 17%, to $4.3 million for the year ended December 31, 2019, from $5.1 million for the year ended December 31, 2018. The decrease in production and ad valorem taxes was attributable to the decrease in production. As a percentage of oil and gas revenue, production and ad valorem taxes was 6% for the year ended December 31, 2019 compared to 5% for the year ended December 31, 2018. The increase during the year ended December 31, 2019 was partially related to approximately $0.7 million increase in ad valorem taxes assessed on our properties compared to the prior year.

Marketing and Transportation Expense

Marketing and transportation expense decreased by less than $0.1 million or 1%, to $2.4 million for the year ended December 31, 2019, from $2.4 million for the year ended December 31, 2018. As a percentage of revenue, marketing and transportation expense was 3% during the year ended December 31, 2019 as compared to 2% for same period in the prior year. Marketing and transportation expense as a percentage of revenue was lower during the year ended December 31, 2018 due to certain oil and gas interests that the Company owns in the Eagle Ford that contributed a significant amount of production but contractually are not charged for any marketing and transportation expenses.

Amortization of Royalty Interests in Oil and Natural Gas Properties Expense

Amortization of royalty interests in oil and natural gas properties expense decreased $4.2 million, or 25%, to $12.7 million for the year ended December 31, 2019, from $17.0 million for the year ended December 31, 2018. The decrease in amortization of royalty interests in oil and gas properties expense was attributable to a portion of our interests in certain oil and natural gas properties sold during Q1 2018 having had a higher amortization rate in addition to a decrease in production during the year ended December 31, 2019.

General, Administrative and Other Expense

General, administrative and other expense increased by $2.4 million, or 25%, to $11.9 million for the year ended December 31, 2019, from $9.5 million for the year ended December 31, 2018. The increase in general, administrative and other expense was attributable to the change in management related to the Transactions and the additional costs incurred related to being a publicly traded company. In addition, the Company incurred $2.5 million in non-cash stock-based compensation expense during 2019 in connection with the implementation of our long-term incentive plan.

Interest Expense

Interest expense increased by $0.1 million, or 6%, to $2.5 million for the year ended December 31, 2019, from $2.4 million for the year ended December 31, 2018. The increase in interest expense was attributable to greater average outstanding borrowings partially offset by lower interest rates under our Credit Facility.

Income Taxes

Income tax expense increased to $3.9 million for the year ended December 31, 2019, compared to $3.3 million for the year ended December 31, 2018. The increase in income taxes was attributable to the Company only incurring income taxes for a portion of the prior year because the Transactions did not take place until August 23, 2018. Prior to the Transactions, Royal was treated as a partnership and was not subject to income taxes.

Comparison of the Year Ended December 31, 2018 to the Year Ended December 31, 2017:

Oil and Gas Revenues

Oil and gas revenues increased $2.7 million, or 3%, to $98.7 million for the year ended December 31, 2018, from $96.0 million for the year ended December 31, 2017. The increase in oil and gas revenues was attributable to a net increase in realized commodity prices offset by a decrease in oil, natural gas liquids and natural gas production caused by the sale of a proportion of our interests in certain oil and natural gas properties in February 2018.

Production and Ad Valorem Taxes

Production and ad valorem taxes decreased $0.1 million, or 2%, to $5.1 million for the year ended December 31, 2018, from $5.2 million for the year ended December 31, 2017. The decrease in production and ad valorem taxes was attributable to the decrease in production. As a percentage of oil and gas revenue, production and ad valorem taxes was 5% for each of the years ended December 31, 2018 and 2017.

Marketing and Transportation Expense

Marketing and transportation expense decreased $4.1 million, or 64%, to $2.4 million for the year ended December 31, 2018, from $6.5 million for the year ended December 31, 2017. The decrease in marketing and transportation expense was attributable to a net change in the production from leases that are burdened by marketing and transportation costs to leases that are not burdened by marketing and transportation costs. This change was caused by a sale of a portion of our interests in certain oil and natural gas properties in February 2018 and new production from existing properties.

Amortization of Royalty Interests in Oil and Natural Gas Properties Expense

Amortization of royalty interests in oil and natural gas properties expense decreased $16.9 million, or 50%, to $17.0 million for the year ended December 31, 2018, from $33.8 million for the year ended December 31, 2017. The decrease in amortization of royalty interests in oil and natural gas properties expense was attributable to decreased production and amortization expense attributable to a portion of our interests in certain oil and natural gas properties that were sold during Q4 2017 and Q1 2018 that had a high amortization rate.

General, Administrative and Other Expense

General, administrative and other expense increased by $1.3 million, or 16%, to $9.5 million for the year ended December 31, 2018, from $8.2 million for the year ended December 31, 2017. The increase in general, administrative and other expense was attributable to the change in management related to the Transactions as the Company is in the process of building its employee base to support the business.

Interest Expense

Interest expense decreased by $0.4 million, or 14%, to $2.4 million for the year ended December 31, 2018, from $2.7 million for the year ended December 31, 2017. The decrease is interest expense was attributable to the extinguishment of the Royal indebtedness at the closing of the Transactions, along with a lower average debt drawn during the year.

Income Taxes

Income tax expense increased by $3.3 million for the year ended December 31, 2018, from $0.0 million for the year ended December 31, 2017. The increase in income taxes was attributable to Royal historically being treated as a partnership which changed as a part of the Transactions. Falcon is treated as a C-Corp and accordingly is subject to federal income taxes.

Adjusted EBITDA

Adjusted EBITDA is a supplemental non-GAAP financial measure used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We believe Adjusted EBITDA is useful because it allows us to evaluate our performance and compare the results of our operations period to period without regard to our financing methods or capital structure. In addition, management uses Adjusted EBITDA to evaluate cash flow available to pay dividends to our common stockholders.

We define Adjusted EBITDA as net income plus interest expense, net, depletion expense, provision for (benefit from) income taxes and share-based compensation less gain (loss) on the sale of assets which related to a pre-Transactions sale of certain oil and gas interests by Royal. Adjusted EBITDA is not a measure of net income as determined by GAAP. We exclude the items listed above from net income in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as historic costs of depreciable assets, none of which are components of Adjusted EBITDA.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income, royalty income, cash flow from operating activities or any other measure of financial performance presented in accordance with GAAP. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies.

The following table presents a reconciliation of net income to Adjusted EBITDA, our most directly comparable GAAP financial measure for the periods indicated (in thousands).

	Year Ended December 31,		
	2019	2018	2017
Net income	$ 30,914	$ 101,107	$ 75,673
Income attributable to discontinued operations	-	(2,139)	(2,978)
Interest expense, net	2,489	2,350	2,746
Depletion	12,737	16,962	33,837
Income taxes	3,918	3,292	-
Gain on the sale of assets	-	(41,382)	(31,441)
Share based compensation	2,549	-	-
Adjusted EBITDA	$ 52,607	$ 80,190	$ 77,837

Liquidity and Capital Resources

Overview

Our primary sources of liquidity have historically been cash flows from operations and equity and debt financings, and our primary uses of cash are for dividends and for the acquisition of additional Royalties. We intend to finance potential future acquisitions through a combination of cash on hand, borrowings under our Credit Facility and, subject to market conditions and other factors, proceeds from one or more capital market transactions, which may include debt or equity offerings. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including commodity prices and general economic, financial, competitive, legislative, regulatory and other factors, including weather.

Our shareholders agreement does not require us to distribute any of the cash we generate from operations. We believe, however, that it is in the best interests of our stockholders if we distribute a substantial portion of the cash we generate from operations. Cash dividends are made to the common stockholders of record on the applicable record date, generally within 60 days after the end of each quarter. Available cash for each quarter's dividend is determined by the Board of Directors following the end of such quarter. Available cash for each quarter generally equals Adjusted EBITDA reduced for cash needed for debt service, income tax requirements and other contractual obligations and fixed charges that the Board of Directors deems necessary or appropriate, if any.

The following table presents cash distributions approved by the Board of Directors of our general partner for the periods presented.

Quarter Ended	Total Quarterly Dividend Per Share	Total Cash Dividends	Payment Date	Shareholders Record Date
December 31, 2019	$ 0.1350	$ 6,205	March 9, 2020	February 25, 2020
September 30, 2019	$ 0.1350	$ 6,203	December 3, 2019	November 20, 2019
June 30, 2019	$ 0.1500	$ 6,879	September 6, 2019	August 26, 2019
March 31, 2019	$ 0.1750	$ 8,026	May 29, 2019	May 17, 2019
December 31, 2018	$ 0.2000	$ 9,171	February 28, 2019	February 21, 2019
September 30, 2018(1)	$ 0.0950	$ 4,356	November 15, 2018	November 8, 2018

(1) Represents the initial pro rata distribution of our quarterly dividend for the period from August 23, 2018 through September 30, 2018.

Indebtedness

Falcon Credit Facility

On the Closing Date, we entered into a credit facility with Citibank, N.A., as administrative agent and collateral agent for the lenders from time to time party thereto (the "Credit Facility"). The Credit Facility provides for a maximum credit amount of $500.0 million and a borrowing base based on our oil and natural gas reserves and other factors of $90.0 million, subject to scheduled semi-annual and other borrowing base redeterminations and expires on the fifth anniversary of the Closing Date. On the Closing Date, $38.0 million was drawn under the Credit Facility to fund a portion of the purchase price of the Transactions, to pay transaction expenses, to fund any original issue discount or upfront fees in connection with the "market flex" provisions previously agreed upon and to finance working capital needs and other general corporate purposes. Effective November 8, 2019, in connection with the Company's fall 2019 redetermination, the borrowing base decreased from $105.0 million to $90 million and, as of December 31, 2019, the Company had borrowings of $42.5 million under the Credit Facility at an interest rate of 4.05% and $47.5 million available for future borrowings under the Credit Facility.

Principal amounts borrowed are payable on the maturity date. We have a choice of borrowing at the base rate or LIBOR, with such borrowings bearing interest, payable quarterly in arrears for base rate loans and one month, two-month, three month or six-month periods for LIBOR loans. LIBOR loans bear interest at a rate per annum equal to the rate appearing on the Reuters Reference LIBOR01 or LIBOR02 page as the LIBOR, for deposits in dollars at 12:00 noon (London, England time) for one, two, three, or six months plus an applicable margin ranging from 200 to 300 basis points. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one-month LIBOR loans plus 1%, plus an applicable margin ranging from 100 to 200 basis points. The scheduled redeterminations of our borrowing base take place on April 1st and October 1st of each year.

Obligations under the Credit Facility are guaranteed by us and each of our existing and future, direct and indirect domestic subsidiaries (the "Credit Parties") and are secured by all of the present and future assets of the Credit Parties, subject to customary carve-outs.

The Credit Facility contains certain customary representations and warranties, affirmative covenants, negative covenants and events of default. As of December 31, 2019, the Company was in compliance with such covenants. The negative covenants include restrictions on the Company's ability to incur additional indebtedness, acquire and sell assets, create liens, enter into certain lease agreements, make investments and make distributions.

Prior to the Transactions, Royal had other credit facilities in place which were extinguished at the closing of the Transactions. For a full description of these credit facilities please see "Note 6 – Debt – Royal Credit Facilities."

Cash Flows

Year Ended December 31, 2019 Compared to Year Ended December 31, 2018

A summary of the changes in cash flow data for the years ended December 31, 2019 and 2018 are set forth in the following table (in thousands, except percentages):

	Year Ended December 31,			
	2019	**2018**	**$ Change**	**% Change**
Net cash flows provided by (used in):				
Operating activities	$ 55,229	$ 77,886	$ (22,657)	-29%
Investing activities	(23,353)	122,312	(145,665)	-119%
Financing activities	(36,650)	(203,378)	166,728	-82%

Cash Flow from Operating Activities. Our operating cash flow has historically been sensitive to many variables, the most significant of which is the volatility of prices for the oil and natural gas for which we receive royalty revenue. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict.

The decrease in cash flow provided by operating activities for the year ended December 31, 2019 as compared to the year ended December 31, 2018 was primarily related to a 29% decrease in oil production, a 13% decrease in natural gas production coupled with a 11% decrease in realized oil prices and a 15% decrease in realized natural gas prices period over period partially offset by an increase in working capital primarily driven by the timing of collection of accounts receivables and the timing of payments of accounts payable and accrued expenses.

Cash Flow from Investing Activities. Investing activities are primarily related to the acquisition and disposition of oil and natural gas interests. Cash used in investing activities for the year ended December 31, 2019 was $23.4 million and the majority was related to the acquisition of certain royalty interests in oil and natural gas properties. Cash provided by investing activities for the year ended December 31, 2018 was $122.3 million and the majority was related to the sale of certain interests in our oil and natural gas properties in February 2018.

Cash Flow from Financing Activities. Cash used in financing activities for the year ended December 31, 2019 was $36.7 million, primarily related to dividends and distributions totaling $58.0 million partially offset by a net increase in borrowings under our Credit Facility of $21.5 million. The borrowings under our Credit Facility were primarily used to fund the acquisition of certain royalty interests in oil and gas properties during the period. Cash used in financing activities for the year ended December 31, 2018 was $203.4 million, primarily related to dividends and distributions totaling $159.4 million and debt repayments of $44.0 million.

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

A summary of the changes in cash flow data for the years ended December 31, 2018 and 2017 are set forth in the following table (in thousands, except percentages):

	Year Ended December 31,			
	2018	**2017**	**$ Change**	**% Change**
Net cash flows provided by (used in):				
Operating activities	$ 77,886	$ 80,791	$ (2,905)	-4%
Investing activities	122,312	83,048	39,264	47%
Financing activities	(203,378)	(161,390)	(41,988)	26%

Cash Flow from Operating Activities. Our operating cash flow has historically been sensitive to many variables, the most significant of which is the volatility of prices for the oil and natural gas for which we receive royalty revenue. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict.

The decrease in cash flow provided by operating activities for the year ended December 31, 2018 as compared to the year ended December 31, 2017 was attributable to an increase in net income of $25.4 million, non-cash charges of $2.2 million related to hedging activities and $2.3 million related to deferred income taxes offset by non-cash charges of $9.9 million associated with the increase in the gains on sale of assets and a decrease in depletion of $18.5 million attributable to the sale of certain assets that occurred in Q4 2017 and Q1 2018. In addition, the operating cash flows had a decrease in working capital of $3.3 million. The net changes in working capital were primarily driven by the timing of collection of accounts receivables and the timing of payments of accounts payable and accrued expenses.

Cash Flow from Investing Activities. Investing activities are primarily related to the acquisition and disposition of oil and natural gas interests. Cash provided by investing activities for the year ended December 31, 2018 was $122.3 million and the majority was related to the sale of certain interests in our oil and natural gas properties in February 2018. Cash provided by investing activities for the year ended December 31, 2017 was $83.0 million and the majority was related to the sale of certain interests in our oil and natural gas properties in December 2017.

Cash Flow from Financing Activities. Cash used in financing activities for the year ended December 31, 2018 was $203.4 million, primarily related to dividends and distributions totaling $159.4 million and debt repayments of $44.0 million. Cash used in financing activities for the year ended December 31, 2017 was $161.4 million, primarily attributed to $160.4 million of distributions and debt repayments of $1.0 million.

Contractual Obligations

We have contractual obligations that are required to be settled in cash. Our contractual obligations as of December 31, 2019 were as follows (in thousands):

	Payments Due by Period				
	Total	Less than 1 year	1 to 3 years	3 to 5 years	More than 5 years
Long-term debt obligations	$ 42,500	$ -	$ -	$ 42,500	$ -
Operating lease obligations	992	309	432	214	37
Total	$ 43,492	$ 309	$ 432	$ 42,714	$ 37

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Recently Issued Accounting Pronouncements

For a discussion of recently issued accounting pronouncements that will affect us, see “Note 2—Summary of Significant Accounting Policies—Recently Issued Accounting Pronouncements” to our accompanying consolidated financial statements for the fiscal year ended December 31, 2019.

Critical Accounting Policies and Estimates

Management Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting period. The more significant areas requiring the use of management estimates and assumptions relate to amortization calculations, and estimates of fair value for long-lived assets, and reserves for contingencies and litigation. Management based its estimates on historical experience and on various other assumptions that were believed to be reasonable under the circumstances. Actual results could differ from these estimates.

Royalty Interests in Oil and Natural Gas Properties

Royalty interests include acquired interests in production, development, and exploration stage properties. We follow the successful efforts method of accounting. Under this method, costs to acquire mineral and royalty interests in oil and natural gas properties are capitalized when incurred.

Acquisition costs of proven royalty interests are amortized using the units of production method over the life of the property, which is estimated using proven reserves. Acquisition costs of royalty interests on exploration stage properties, where there are no proven reserves, are not amortized. At such time as the associated unproved interests are converted to proven reserves, the cost basis is amortized using the units of production methodology over the life of the property, using proven reserves. For purposes of amortization, interests in oil and natural gas properties are grouped in a reasonable aggregation of properties with common geological structural features or stratigraphic condition.

Oil and Natural Gas Reserve Quantities

Our independent engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net cash flows. The SEC has defined proved reserves as the estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The process of estimating oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes are material, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Impairment of Royalty Interests in Oil and Natural Gas Properties

We review and evaluate our royalty interests in oil and natural gas properties for impairment when events or changes in circumstances indicate that the related carrying amounts may not be recoverable. When such events or changes in circumstances occur, we estimate the undiscounted future cash flows expected in connection with the properties and compare such future cash flows to the carrying amounts of the properties to determine if the carrying amounts are recoverable. If the carrying value of the properties is determined to not be recoverable based on the undiscounted cash flows, an impairment charge is recognized by comparing the carrying value to the estimated fair value of the properties. The factors used to determine fair value include, but are not limited to, estimates of proved, probable and possible reserves, future commodity prices, the timing of future production and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. No such impairment expense was recorded for the years ended December 31, 2019 or 2018.

Revenue Recognition

Revenues from our Royalties represent the right to receive revenues from oil, natural gas and NGL sales obtained by the operator of the wells in which the Company owns a royalty interest. Royalty income is recognized at the point control of the product is transferred to the purchaser. Virtually all of the pricing provisions in the Company’s contracts are tied to a market index. Royalty interest and revenue recognition related accounting policies are defined and described more fully in Note 2—Summary of Significant Accounting Policies to our consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to the oil and natural gas production of our operators. Realized pricing was primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years and we expect this volatility to continue in the future. The prices that our operators receive for production depend on many factors outside of our or their control. Historically, we have not entered into hedging arrangements to manage commodity price risks.

Revenue Concentration Risk

We are subject to risk resulting from the concentration of oil and gas revenues in producing oil and natural gas properties and receivables with several significant purchasers. For the year ended December 31, 2018, we received approximately 39%, 22%, and 16% of our revenue from ConocoPhillips, EOG, and Devon, respectively. For the year ended December 31, 2019, we received approximately 33%, 29%, and 18% of our revenue from ConocoPhillips, EOG, and Devon, respectively. We do not believe the loss of any single purchaser would materially impact our operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Interest Rate Risk

We have exposure to changes in interest rates on our indebtedness. As of December 31, 2019, we had total borrowings under our Credit Facility of $42.5 million. The impact of a 1% increase in the interest rate on this amount of debt would result in an increase in interest expense of approximately $0.3 million annually, assuming that our indebtedness remained constant throughout the year. We do not currently have any interest rate hedges in place.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required by this Item are set forth on pages F-1 of this Annual Report and are incorporated herein by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our reports filed pursuant to the Exchange Act is properly and timely reported and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

An effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, effectiveness of an internal control system in future periods cannot be guaranteed because the design of any system of internal controls is based in part upon assumptions about the likelihood of future events. There can be no assurance that any control design will succeed in achieving its stated goals under all potential future conditions. Over time certain controls may become inadequate because of changes in business conditions, or the degree of compliance with policies and procedures may deteriorate. As such, misstatements due to error or fraud may occur and not be detected.

We have evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2019 with the participation, and under the supervision, of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2019, our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

During the most recently completed fiscal quarter, there has been no change in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Our management, including our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Our internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer, and effected by the Company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with GAAP.

Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Also, projections of any evaluation of the effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As of December 31, 2019, our management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control - Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on the assessment, management believes that we maintained effective internal control over financial reporting as of December 31, 2019, based on those criteria.

Attestation Report of the Registered Public Accounting Firm

Our independent registered public accounting firm is not required to formally attest to the effectiveness of our internal control over financial reporting for as long as we are an "emerging growth company" pursuant to the provisions of the JOBS Act.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item will be set forth in our definitive proxy statement with respect to our 2020 annual meeting of the stockholders to be filed on or before April 29, 2020 and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth in our definitive proxy statement with respect to our 2020 annual meeting of the stockholders to be filed on or before April 29, 2020 and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

The information required by this item will be set forth in our definitive proxy statement with respect to our 2020 annual meeting of the stockholders to be filed on or before April 29, 2020 and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this item will be set forth in our definitive proxy statement with respect to our 2020 annual meeting of the stockholders to be filed on or before April 29, 2020 and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be set forth in our definitive proxy statement with respect to our 2020 annual meeting of the stockholders to be filed on or before April 29, 2020 and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements

See "Index to Consolidated Financial Statements" set forth on Page F-1.

(a)(2) Financial Statement Schedules

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) Exhibits

The following documents are filed as part of this Annual Report or incorporated by reference:

EXHIBIT INDEX

Exhibit No.	Description
2.1	Contribution Agreement, dated as of June 3, 2018, among Royal Resources L.P., Royal Resources GP L.L.C., Noble Royalties Acquisition Co. LP, Hooks Ranch Holdings LP, DGK ORRI Holdings, LP, DGK ORRI GP LLC, Hooks Holding Company GP, LLC and Osprey Energy Acquisition Corp. (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K (file No. 001-38158) filed June 4, 2018).
3.1	Second Amended and Restated Certificate of Incorporation of Falcon Minerals Corporation, dated as of August 23, 2018 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (file No. 001-38158) filed August 29, 2018).
3.2	Amended and Restated Bylaws of Falcon Minerals Corporation (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K/A (file No. 001-38158) filed January 23, 2019).
4.1	Shareholders' Agreement dated as of August 23, 2018 by and among Falcon Minerals Corporation, Osprey Sponsor, LLC, Edward Cohen, Jonathan Z. Cohen, Daniel C. Herz, Jeffrey F. Brotman, Royal Resources L.P., Royal Resources GP L.L.C., Noble Royalties Acquisition Co. L.P., Hooks Ranch Holdings LP, DGK ORRI Holdings, LP and Blackstone Management Partners, L.L.C. (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (file No. 001-38158) filed August 29, 2018).
4.2	Registration Rights Agreement dated as of August 23, 2018 by and among Falcon Minerals Corporation, Royal Resources L.P., Noble Royalties Acquisition Co., L.P., Hooks Ranch Holdings LP, DGK ORRI Holdings, LP, DGK ORRI GP LLC and Hooks Holdings Company GP, LLC (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (file No 001-38158) filed August 29, 2018).
4.3	Registration Rights Agreement, dated July 20, 2017, by and among Falcon Minerals Corporation and Osprey Sponsor, LLC (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (File No. 001-38158) filed on July 26, 2017).
4.4	Warrant Agreement, dated July 20, 2017, between Falcon Minerals Corporation and Continental Stock Transfer & Trust Company, as warrant agent (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (File No. 001-38158) filed on July 26, 2017).
4.5	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1 (File No. 333-219025) filed on June 28, 2017).
4.6*	Description of Falcon Minerals Corporation registered securities
10.1†	Falcon Minerals Corporation 2018 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (file No. 001-38158) filed on August 29, 2018).
10.2	Credit Agreement, dated as of August 23, 2018 among Falcon Minerals Operating Partnership, LP, as the Borrower, the lenders from time to time party thereto, Citibank, N.A., as administrative agent and collateral agent for the lenders from time to time party thereto and each other issuing bank from time to time party thereto (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (file No. 001-38158) filed on August 29, 2018).
10.3†	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (file No. 001-38158) filed on August 29, 2018).

10.4	Second Amended and Restated Agreement of Limited Partnership of Falcon Minerals Operating Partnership, LP, dated as of August 23, 2018 (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (file No. 001-38158) filed on August 29, 2018).
10.5	Form of Subscription Agreement, dated as of June 3, 2018, by and between Osprey Energy Acquisition Corp. and the subscriber named therein (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (file No. 001-38158) filed June 4, 2018).
10.6	Form of Lockup Agreement, dated as of June 3, 2018, by and between Osprey Energy Acquisition Corp. and the holder named therein (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (file No. 001-38158) filed June 4, 2018).
10.7	Voting Agreement, dated as of June 3, 2018, among Royal Resources L.P., Osprey Sponsor, LLC and certain other persons party thereto (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K (file No. 001-38158) filed June 4, 2018).
10.8†	Form of Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-38158) filed on May 16, 2019).
10.9†	Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 4.9 to the Company's Registration Statement on Form S-8 (File No. 333-228663) filed on December 4, 2018).
10.10†	Form of Incentive Stock Option Agreement (incorporated by reference to Exhibit 4.10 to the Company's Registration Statement on Form S-8 (File No. 333-228663) filed on December 4, 2018).
10.11†	Form of Nonqualified Stock Option Agreement (incorporated by reference to Exhibit 4.11 to the Company's Registration Statement on Form S-8 (File No. 333-228663) filed on December 4, 2018).
10.12	Master Management Services Agreement (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (file No. 001-38158) filed on August 29, 2018).
10.13†	Form of Performance Stock Unit Agreement (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (File No. 001-38158) filed on May 16, 2019).
10.14†	Employment Agreement, dated April 19, 2019, by and between Falcon Minerals Corporation and Daniel C. Herz (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (file No. 001-38158) filed on April 25, 2019).
10.15†	Restricted Stock Award Agreement, dated April 19, 2019, by and between Falcon Minerals Corporation and Daniel C. Herz (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (file No. 001-38158) filed on April 25, 2019).
10.16†	Performance Stock Unit Agreement, dated April 19, 2019, by and between Falcon Minerals Corporation and Daniel C. Herz (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (file No. 001-38158) filed on April 25, 2019).
10.17†	Super Performance Stock Unit Agreement, dated April 19, 2019, by and between Falcon Minerals Corporation and Daniel C. Herz (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (file No. 001-38158) filed on April 25, 2019).
21.1*	Subsidiaries of the Company
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of Principal Executive Officer Pursuant to Securities Exchange Act Rules 13a-14(a) and 15(d)-14(a), as adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer Pursuant to Securities Exchange Act Rules 13a-14(a) and 15(d)-14(a), as adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Reserve Report of Ryder Scott Company, L.P.
101.INS*	XBRL Instance Document.

101.SCH* XBRL Taxonomy Extension Schema Document.

101.CAL* XBRL Taxonomy Extension Calculation Linkbase Document.

101.DEF* XBRL Taxonomy Extension Definition Linkbase Document.

101.LAB* XBRL Taxonomy Extension Label Linkbase Document.

101.PRE* XBRL Taxonomy Extension Presentation Linkbase Document.

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* Filed herewith

** Furnished herewith

† Compensatory plan or arrangement.

ITEM 16. FORM 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

Date: March 13, 2020

By: FALCON MINERALS CORPORATION

By: /s/ DANIEL C. HERZ
Daniel C. Herz
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ DANIEL C. HERZ Daniel C. Herz	Chief Executive Officer, President (Principal Executive Officer)	March 13, 2020
/s/ BRYAN C. GUNDERSON Bryan C. Gunderson	Chief Financial Officer (Principal Financial Officer)	March 13, 2020
/s/ STEPHEN J. PILATZKE Stephen J. Pilatzke	Chief Accounting Officer (Principal Accounting Officer)	March 13, 2020
/s/ JONATHAN Z. COHEN Jonathan Z. Cohen	Chairman	March 13, 2020
/s/ EDWARD E. COHEN Edward E. Cohen	Director	March 13, 2020
/s/ BRIAN L. FRANK Brian L. Frank	Director	March 13, 2020
/s/ STEVEN R. JONES Steven R. Jones	Director	March 13, 2020
/s/ WILLIAM D. ANDERSON William D. Anderson	Director	March 13, 2020
/s/ ALAN HIRSHBERG Alan Hirshberg	Director	March 13, 2020
/s/ ERIC LIAW Eric Liaw	Director	March 13, 2020
/s/ ADAM M. JENKINS Adam M. Jenkins	Director	March 13, 2020
/s/ JONATHAN R. HAMILTON Jonathan R. Hamilton	Director	March 13, 2020

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

FALCON MINERALS CORPORATION

FALCON MINERALS CORPORATION

Report of Independent Registered Public Accounting Firm

To the Board of Directors and shareholders of Falcon Minerals Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Falcon Minerals Corporation and subsidiaries (the "Company") as of December 31, 2019 and 2018, the related consolidated statements of operations, cash flows, and shareholder’s equity and partners’ capital for each of the three years in the period ended December 31, 2019, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Emphasis of Matter

As discussed and defined in Note 1 and Note 4 to the financial statements, the Company completed the Transactions on August 23, 2018, which has been accounted for as a reverse recapitalization. Concurrent with the close of the Transactions, the Company's capital structure was adjusted and is now a corporation subject to U.S. federal income taxes.

/s/ Deloitte & Touche LLP

Houston, Texas
March 13, 2020

We have served as the Company's auditor since 2012.

FALCON MINERALS CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands)

	December 31, 2019	December 31, 2018
Assets:		
Current assets:		
Cash and cash equivalents	$ 2,543	$ 7,317
Account receivable	7,889	11,271
Prepaid expenses	1,182	1,524
Total current assets	11,614	20,112
Royalty interests in oil and natural gas properties, net of accumulated amortization of $130,342 and $117,605 respectively	219,192	209,168
Property and equipment, net of accumulated depreciation of $75 and $0	517	-
Deferred tax asset, net	56,352	58,773
Other assets	2,530	3,182
Total assets	$ 290,205	$ 291,235
Liabilities and shareholders' equity:		
Current liabilities:		
Accounts payable and accrued expenses	$ 2,206	$ 521
Credit facility	42,500	21,000
Other liabilities	473	-
Total liabilities	45,179	21,521
Commitments and contingencies (See Note 13)		
Shareholders' equity:		
Preferred stock, $0.0001 par value; 1,000,000 shares authorized; none issued and outstanding	-	-
Class A common stock, $0.0001 par value; 240,000,000 shares authorized; 45,963,716 and 45,855,000 shares issued and outstanding as of December 31, 2019 and 2018, respectively	5	5
Class C common stock, $0.0001 par value; 120,000,000 shares authorized; 40,000,000 issued and outstanding as of December 31, 2019 and 2018	4	4
Additional paid in capital	129,127	137,866
Non-controlling interests	115,890	127,029
Retained earnings	-	4,810
Total shareholders' equity	245,026	269,714
Total liabilities, shareholders' equity	$ 290,205	$ 291,235

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

FALCON MINERALS CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Year Ended December 31,		
	2019	**2018**	**2017**
Revenues:			
Oil and gas sales	$ 68,463	$ 98,655	$ 95,972
Gain (loss) on hedging activities	-	(1,456)	1,791
Total revenue	68,463	97,199	97,763
Operating expenses:			
Production and ad valorem taxes	4,262	5,143	5,242
Marketing and transportation	2,396	2,368	6,505
Amortization of royalty interests in oil and natural gas properties	12,737	16,962	33,837
General, administrative and other	11,912	9,544	8,213
Total operating expenses	31,307	34,017	53,797
Operating income	37,156	63,182	43,966
Other income (expense):			
Gain on the sale of assets	-	41,382	31,441
Other income	165	46	34
Interest expense	(2,489)	(2,350)	(2,746)
Total other income (expense)	(2,324)	39,078	28,729
Income before income taxes	34,832	102,260	72,695
Provision for income taxes	3,918	3,292	-
Income from continuing operations	30,914	98,968	72,695
Income from discontinued operations	-	2,139	2,978
Net income	30,914	101,107	75,673
Net income attributable to non-controlling interests	(16,564)	(10,982)	(155)
Net income attributable to common shareholders/unitholders	$ 14,350	$ 90,125	$ 75,518
Earnings per common share:			
Common shares (basic and diluted)	$ 0.31	$ 0.20	N/A
Weighted average number of shares outstanding:			
Common shares (basic and diluted)	45,893	45,855	N/A

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

FALCON MINERALS CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Year Ended December 31,		
	2019	**2018**	**2017**
Cash flow from operating activities:			
Net income	$ 30,914	$ 101,107	$ 75,673
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Gain on sale of assets	-	(41,382)	(31,441)
Unrealized (gain) loss on hedging activities	-	1,151	(1,040)
Amortization of royalty interests in oil and natural gas properties	12,737	18,536	37,085
Accretion of asset retirement obligation	-	7	34
Amortization of debt issuance costs	643	457	95
Deferred rent	473	-	
Depreciation of property and equipment	75	-	
Share based compensation	2,548	-	
Deferred income taxes	2,421	2,285	-
Cash paid to settle derivatives	-	(1,151)	-
Changes in operating assets and liabilities			
Accounts receivable	3,383	1,882	(2,368)
Prepaid expenses	342	(278)	(1,069)
Other assets	10	(182)	-
Accounts payable and accrued expenses	1,683	(4,399)	3,311
Other liabilities	-	(147)	511
Net cash provided by operating activities	55,229	77,886	80,791
Cash flows from investing activities:			
Additions to oil and natural gas properties	-	(523)	(3,518)
Decrease in advances to operators	-	-	225
Cash acquired in the Transactions	-	2,920	-
Proceeds from the sale of assets	-	121,130	86,341
Acquisition of oil and natural gas properties	(22,761)	(1,215)	-
Purchase of property and equipment	(592)	-	-
Net cash provided by (used in) investing activities	(23,353)	122,312	83,048
Cash flows from financing activities:			
Distributions to partners	-	(143,788)	(160,390)
Distribution of subsidiaries	-	(7,125)	-
Contributions	-	(8)	-
Proceeds from long-term debt	39,000	-	-
Repayments of long-term debt	(17,500)	(44,000)	(1,000)
Deferred financing fees	-	-	-
Dividends paid	(30,293)	(4,356)	-
Distributions to non-controlling interests	(27,703)	(4,101)	-
Dividend equivalent rights paid	(154)	-	-
Net cash used in financing activities	(36,650)	(203,378)	(161,390)
Net increase (decrease) in cash and cash equivalents	(4,774)	(3,180)	2,449
Cash and cash equivalents, beginning of period	7,317	10,497	8,048
Cash and cash equivalents, end of period	$ 2,543	$ 7,317	$ 10,497
Supplemental disclosure of cash flow information:			
Cash paid for interest	$ 1,846	$ 1,834	$ 2,703
Cash paid for income taxes	1,260	1,350	-
Non-cash investing and financing activities:			
Credit facility prior to the Transactions	-	38,000	-
Distribution of long-term debt to non-acquired entities prior to the Transactions	-	31,000	-
Deferred financing fees prior to the Transactions	-	3,214	-
Deferred tax asset related to the Transactions	-	60,603	-
Accounts payable related to capital expenditures	-	-	72

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

FALCON MINERALS CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND PARTNERS' CAPITAL

(In thousands)

	Class A Common Stock		Class C Common Stock						
	Shares	Amount	Shares	Amount	Additional Paid In Capital	Partners' Capital	Non-controlling interests	Retained Earnings	Total Stockholder's Equity
Balance at December 31, 2016	-	$ -	-	$ -	$ -	$ 373,237	$ 637	$ -	$ 373,874
Net income	-	-	-	-	-	75,518	155	-	75,673
Distributions to partners	-	-	-	-	-	(160,227)	(163)	-	(160,390)
Balance at December 31, 2017	-	$ -	-	$ -	$ -	$ 288,528	$ 629	$ -	$ 289,157
Distributions to partners	-	-	-	-	-	(143,750)	(38)	-	(143,788)
Net income prior to Transactions	-	-	-	-	-	80,959	115	-	81,074
Recapitalization in connection with the Transactions	45,855	5	40,000	4	137,866	(225,737)	119,557	-	31,695
Net income post Transactions	-	-	-	-	-	-	10,867	9,166	20,033
Distributions to non-controlling interests	-	-	-	-	-	-	(4,101)	-	(4,101)
Dividends to shareholders ($0.095 per share)	-	-	-	-	-	-	-	(4,356)	(4,356)
Balance at December 31, 2018	45,855	$ 5	40,000	$ 4	$ 137,866	$ -	$ 127,029	$ 4,810	$ 269,714
Vested restricted stock grants	109	-	-	-	-	-	-	-	-
Stock-based compensation	-	-	-	-	2,548	-	-	-	2,548
Dividend equivalent rights paid	-	-	-	-	(154)	-	-	-	(154)
Distributions to non-controlling interests	-	-	-	-	-	-	(27,703)	-	(27,703)
Dividends to shareholders ($0.66 per share)	-	-	-	-	(11,133)	-	-	(19,160)	(30,293)
Net income	-	-	-	-	-	-	16,564	14,350	30,914
Balance at December 31, 2019	45,964	$ 5	40,000	$ 4	$ 129,127	$ -	$ 115,890	$ -	$ 245,026

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

FALCON MINERALS CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization and Presentation

Organization and Description of Business

Falcon Minerals Corporation (the "Company" or "Falcon" and formerly named Osprey Energy Acquisition Corp.) was a blank check company, incorporated in Delaware in June 2016. The Company was formed for the purpose of acquiring, through a merger, capital stock exchange, asset acquisition, stock purchase, reorganization, recapitalization, or other similar business transaction, one or more operating businesses or assets (a "Business Combination").

On August 23, 2018 (the "Closing Date"), the Company completed the acquisition of the equity interests (the "Equity Interests") in certain of the subsidiaries (the "Royal Entities") of Noble Royalties Acquisition Co., LP ("NRAC"), Hooks Ranch Holdings LP ("Hooks Holdings"), DGK ORRI Holdings, LP ("DGK"), DGK ORRI GP LLC ("DGK GP") and Hooks Holding Company GP, LLC ("Hooks GP", and collectively with NRAC, Hooks Holdings, DGK, and DGK GP, the "Contributors"). The acquisition was made pursuant to the Contribution Agreement, dated as of June 3, 2018 (the "Contribution Agreement"), by and among the Company, Royal Resources L.P. ("Royal"), Royal Resources GP L.L.C. ("Royal GP") and the Contributors. The acquisition of the Royal Entities pursuant to the Contribution Agreement is referred to as the "Business Combination" and the Business Combination together with the other transactions contemplated by the Contribution Agreement are referred to herein as the "Transactions."

Pursuant to the Contribution Agreement, on the Closing Date, the Company contributed cash to Falcon Minerals Operating Partnership, LP, a Delaware limited partnership and wholly owned subsidiary of the Company ("Opco"), in exchange for (a) a number of OpCo Common Units representing limited partnership interests in Opco (the "OpCo Common Units") equal to the number of shares of the Company's Class A common stock, par value $0.0001 per share (the "Class A Common Stock"), outstanding as of the Closing Date and (b) a number of Opco warrants exercisable for OpCo Common Units equal to the number of the Company's warrants outstanding as of the Closing Date. The Company controls Opco through Falcon Minerals GP, LLC, a Delaware limited liability company, a wholly owned subsidiary of the Company and the sole general partner of Opco ("Opco GP").

On the Closing Date, Falcon completed the acquisition of the Equity Interests and in return the Contributors received (i) $400 million of cash and (ii) 40 million OpCo Common Units. The Company also issued to the Contributors 40 million shares of non-economic Class C common stock of the Company, which entitles each holder to one vote per share. The OpCo Common Units are redeemable on a one-for-one basis for shares of Class A Common Stock at the option of the Contributors. Upon the redemption by any Contributor of OpCo Common Units for Class A Common Stock, a corresponding number of shares of Class C Common Stock held by such Contributor will be cancelled.

In connection with the closing of the Business Combination (the "Closing"), the Company changed its name from "Osprey Energy Acquisition Corp." to "Falcon Minerals Corporation." The Company is now structured as an "Up-C," meaning that substantially all the assets of the Company are held by OpCo, and the Company's only operating asset is its equity interest in OpCo. Each OpCo Common Unit, together with one share of Class C Common Stock, is exchangeable for one share of Class A Common Stock at the option of the holder pursuant to the terms of the Company's and OpCo's organizational documents, subject to certain restrictions.

The Company's assets, via its controlling interest in OpCo, consist of royalty interests, mineral interests, non-participating royalty interests and overriding royalty interests, or ORRIs (collectively, "Royalties"), underlying approximately 256,000 gross unit acres that are concentrated in what the Company believes is the "core-of-the-core" of liquids-rich condensate region of the Eagle Ford Share in Karnes, DeWitt and Gonzales Counties, Texas. The company owns additional assets of approximately 75,000 gross acres in Pennsylvania, Ohio and West Virginia that is prospective for Marcellus Shale.

These royalties entitle the holder to a portion of the production of oil and natural gas from the underlying acreage at the sales price received by the operator, net of any applicable post-production expenses and taxes. The holder of these interests has no obligation to fund exploration and development costs, lease operating expenses or plugging and abandonment costs at the end of a well's productive life.

Note 2—Summary of Significant Accounting Policies

Basis of Presentation

The accompanying audited consolidated financial statements of the Company have been prepared in accordance with generally accepted accounting principles ("GAAP") in the U.S. and pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). All intercompany balances and transactions are eliminated in consolidation.

The acquisition of the Royal Entities has been accounted for as a reverse recapitalization. Under this method of accounting, Falcon will be treated as the acquired company and Royal will be treated as the acquirer for financial reporting purposes. Therefore, the consolidated financial results include information regarding Royal as the Company's predecessor entity, which includes certain interests in subsidiary companies which were not acquired by the Company in the Transactions. Thus, the financial statements included in this report reflect (i) the historical operating results of Royal prior to the Transactions: (ii) the combined results of the Company, OpCo and Royal following the Transactions; (iii) the assets, liabilities and partners' capital of Royal at their historical costs; and (iv) the Company's equity and earnings per share presented for the period from the Closing Date of the Transaction. The Royal subsidiaries that were contributed in the Transactions are VickiCristina, LP, DGK ORRI Company, L.P., Noble EF DLG LP, Noble EF LP and Noble Marcellus LP. The interests in Riverbend Natural Resources, L.P. ("RNR") and KGD ORRI, L.P. were not contributed in the Transactions (the "Non-Contributed Entities"). The RNR interests that were not contributed in the Transactions are classified as discontinued operations in the consolidated statements of operations.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and include all highly liquid investments purchased with a maturity of three months or less and money market funds. The Company maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Company has not experienced any significant losses from such investments.

Use of Estimates

The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities; disclosure of contingent assets and liabilities at the date of the financial statements; the reported amounts of revenues and expenses during the reporting periods; and the quantities and values of proved oil, natural gas and NGLs reserves used in calculating depletion and assessing impairment of oil and natural gas properties. Actual results could differ significantly from these estimates. Significant estimates made by management include the quantities of proved oil, natural gas and NGL reserves, related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties, fair value of the Company's warrants, estimates of current and deferred income taxes. While management believes these estimates are reasonable, changes in facts and assumptions or the discovery of new information may result in revised estimates. Actual results could differ from these estimates and it is reasonably possible these estimates could be revised in the near term, and these revisions could be material.

Accounts Receivable

The Company's accounts receivable balance results primarily from operators' sales of oil and natural gas to their customers. Accounts receivable are recorded at the contractual amounts and do not bear interest. The Company reserves for specific accounts receivables when it is probable that all or a part of an outstanding balance will not be collected. The Company regularly reviews collectability and establishes or adjusts the allowance as necessary using the specific identification method. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is considered doubtful. As of December 31, 2019 and 2018, the Company had not recorded any reserves for uncollectible amounts or deemed any amounts to be uncollectible.

Royalty Interests in Oil and Natural Gas Properties

The Company follows the successful efforts method of accounting for oil and natural gas operations. Under this method, costs to acquire mineral and royalty interests in oil and natural gas properties are capitalized when incurred. Acquisitions of royalty interests of oil and natural gas properties are considered asset acquisitions and are recorded at cost.

Acquisition costs of proven royalty interests are amortized using the units of production method over the life of the property, which is estimated using proven reserves. Acquisition costs of royalty interests on unproved properties, where there are no proven reserves, are not amortized. When the associated exploration stage interests are converted to proven reserves, the cost basis is amortized using the units of production methodology over the life of the property, using proven reserves. For purposes of amortization, interests in oil and natural gas properties are grouped in a reasonable aggregation of properties with common geological structural features or stratigraphic condition.

We review and evaluate our royalty interests in oil and natural gas properties for impairment when events or changes in circumstances indicate that the related carrying amounts may not be recoverable. Proved oil and gas properties are reviewed for impairment when events and circumstances indicate a potential decline in the fair value of such properties below the carrying value, such as a downward revision of the reserve estimates or lower commodity prices. When such events or changes in circumstances occur, we estimate the undiscounted future cash flows expected in connection with the properties and compare such future cash flows to the carrying amounts of the properties to determine if the carrying amounts are recoverable. If the carrying value of the properties is determined to not be recoverable based on the undiscounted cash flows, an impairment charge is recognized by comparing the carrying value to the estimated fair value of the properties. The factors used to determine fair value include, but are not limited to, estimates of proved, probable and possible reserves, future commodity prices, the timing of future production and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. There was no such impairment of proved oil and natural gas properties for the years ended December 31, 2019 or 2018.

Unproved properties are also assessed for impairment periodically on a depletable unit basis when facts and circumstances indicate that the carrying value may not be recoverable, at which point an impairment loss is recognized to the extent the carrying value exceeds the estimated recoverable value. The carrying value of unproved properties, including unleased mineral rights, is determined based on management's assessment of fair value using factors similar to those previously noted for proved properties, as well as geographic and geologic data. There was no impairment of unproved properties for the years ended December 31, 2019 and 2018.

Upon the sale of a complete depletable unit, the book value thereof, less proceeds or salvage value, is charged to income. Upon the sale or retirement of an individual well, or an aggregation of interests which make up less than a complete depletable unit, the proceeds are credited to accumulated DD&A, unless doing so would significantly alter the DD&A rate of the depletable unit, in which case a gain or loss would be recorded.

Debt Issuance Costs

Other assets include capitalized financing costs of $2.4 million and $3.0 million as of December 31, 2019 and 2018, respectively. The costs are associated with the Company's credit agreement and are being amortized over the term of the credit agreement.

Fair Value of Financial Instruments

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. Fair value measurements are derived using inputs and assumptions that market participants would use in pricing an asset or liability, including assumptions about risk. GAAP establishes a valuation hierarchy for disclosure of the inputs used to measure fair value. This three-tier hierarchy classifies fair value amounts recognized or disclosed in the consolidated financial statements based on the observability of inputs used to estimate such fair values. The classification within the hierarchy of an asset or liability is determined based on the lowest level input that is significant to the fair value measurement. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). At each balance sheet reporting date, the Company categorizes its assets and liabilities recorded at fair value using this hierarchy.

The amounts reported in the balance sheet for cash equivalents, accounts receivable, accounts payable and accrued liabilities approximate their fair value because of the short-term maturities of these instruments (Level 1). Because the Credit Facility (as defined in "Note 6 – Debt – Falcon Credit Facility" below) has a market rate of interest, its carrying amount approximated fair value (Level 2).

Revenue from Contracts with Customers

Revenues from royalty properties are recorded under the cash receipts approach as directly received from the remitters' statement accompanying the revenue check. Since the revenue checks are generally received 30 to 90 days after the production month, the Company accrues for revenue earned but not received by estimating production volumes and product prices. Revenues from lease bonus are recorded upon receipt. The lease bonus is separate from the lease itself and is recognized as revenue to the Company upon receipt of payment.

Transaction price allocated to remaining performance obligations

The Company's right to royalty income does not originate until production occurs and, therefore, is not considered to exist beyond each day's production. Therefore, there are no remaining performance obligations under any of the Company's royalty income contracts.

Contract balances

Under the Company's royalty income contracts, it would have the right to receive royalty income from the producer once production has occurred, at which point payment is unconditional. Accordingly, the Company's royalty income contracts do not give rise to contract assets or liabilities.

Prior-period performance obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for certain oil, natural gas and NGLs sales may not be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of royalty income to be received based upon the Company's interest. The Company records the differences between its estimates and the actual amounts received for royalties in the quarter that payment is received from the producer. Identified differences between the Company's revenue estimates and actual revenue received historically have not been significant. For the year ended December 31, 2019, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material. The Company believes that the pricing provisions of its oil, natural gas and NGLs contracts are customary in the industry. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the royalties related to expected sales volumes and prices for those properties are estimated and recorded.

Income Taxes

The Company under ASC 740 uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (i) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (ii) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

ASC 740 prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of tax positions taken or expected to be taken in a tax return. For those benefits to be recognized, a tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. The Company recognizes accrued interest and penalties related to unrecognized tax benefits as income tax expense. No amounts were accrued for the payment of interest and penalties at December 31, 2019. The Company is currently not aware of any issues under review that could result in significant payments, accruals or material deviation from its position. The Company is subject to income tax examinations by major taxing authorities since inception.

Royal was historically treated as a partnership for federal income tax purposes, with each partner being separately taxed on its share of taxable income; therefore, there is no federal income tax expense reflected in Royal's historical financial statements prior to the Transactions.

Derivative Financial Instruments

Since the Transactions, Falcon has not engaged in any derivative transactions. Historically, Royal used derivative financial instruments to reduce exposure to fluctuations in commodity prices. The transactions were in the form of crude swaps. Royal's derivative instruments were not designated as cash flow hedges for accounting purposes for any periods presented. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses from derivatives are included in the cash flows from operating activities. Royal's derivative financial instruments were extinguished in connection with the Transactions.

Segment Reporting

The Company derives revenue from royalty interests, mineral interests, non-participating royalty interests and overriding royalty interests, or ORRIs (collectively "Royalties"), in oil and natural gas properties in North America. The Company operates in a single operating and reportable segment. Operating segments are defined as components of an enterprise for which separate financial information is evaluated regularly by the chief operating decision maker ("CODM") in deciding how to allocate resources and assess performance. The Company's Chief Executive Officer has been determined to be the CODM and allocates resources and assesses performance based upon financial information at the consolidated level.

Recently Issued Accounting Pronouncements

The Company is an "emerging growth company" ("EGC") as defined by the JOBS Act. The JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 13(a) of the Exchange Act for complying with new or revised accounting standards. In other words, an emerging growth company can delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. The Company has elected to avail itself of this exemption and, as a result, its financial statements may not be comparable to the financial statements of issuers that are required to comply with the effective dates for new or revised accounting standards that are applicable to public companies. Section 107 of the JOBS Act provides that the Company can elect to opt out of the extended transition period at any time, which election is irrevocable.

In February 2016, the FASB issued new guidance which amends various aspects of existing guidance for leases. The new guidance requires an entity to recognize assets and liabilities arising from a lease for both financing and operating leases, along with additional qualitative and quantitative disclosures. The main difference between previous GAAP and the new standard is the recognition of lease assets and lease liabilities by lessees on the balance sheet for those leases classified as operating leases under previous GAAP. As a result, the Company will have to recognize a liability representing its lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term on the balance sheet. The new guidance is effective for fiscal years beginning after December 15, 2019, with early adoption permitted. The Company plans to use a modified retrospective transition method to apply the new standard to leases that exist as of the adoption date of January 1, 2020. The Company did not early adopt. Based on evaluations to-date, the new guidance will not have a material impact on the Company's consolidated financial statements and related disclosures as this guidance does not apply to leases to explore for or use minerals, oil, natural gas, and similar resources.

In August 2016, the FASB issued new guidance which makes eight targeted changes to how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The update provides specific guidance on cash flow classification issues that are not currently addressed by GAAP and thereby reduces the current diversity in practice. The standard is effective for the Company's financial statements issued for fiscal years beginning after December 15, 2018 and interim periods within those fiscal years. Early adoption is permitted. The Company adopted this update prospectively and the adoption of this requirement did not have a significant impact on the Company's financial condition, results of operations, cash flows and related disclosures.

In June 2016, the FASB issued new guidance related to Accounting Standards Update 2016-13, "Financial Instruments – Credit Losses" ("ASU 2016-13"). This update affects entities holding financial assets and net investment in leases that are not accounted for at fair value through net income. The amendments affect loans, debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, reinsurance receivables, and any other financial assets not excluded from the scope that have the contractual right to receive cash. In November 2018, the FASB issued a further update to ASU 2016-13. This update clarifies that receivables arising from operating leases are not in scope of this topic, but rather the leasing standard. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. The Company does not believe the adoption of this standard will have an impact on its financial statements.

In January 2017, the FASB issued new guidance which provides clarifications to evaluating when a set of transferred assets and activities (collectively, the "set") is a business and provides a screen to determine when a set is not a business. Under the new guidance, when substantially all of the fair value of gross assets acquired (or disposed of) is concentrated in a single identifiable asset, or group of similar assets, the assets acquired would not represent a business. Also, to be considered a business, an acquisition would have to include an input and a substantive process that together significantly contribute to the ability to produce outputs. The new standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, and should be applied on a prospective basis to any transactions occurring within the period of adoption. Early adoption is permitted for interim or annual periods in which the financial statements have not been issued. The adoption of this requirement did not have a significant impact on the Company's financial condition, results of operations, cash flows and related disclosures.

In June 2018, the FASB issued new guidance which provides clarifications with respect to stock compensation issued to non-employees. This update applies the existing employee guidance to nonemployee share-based transactions, with the exception of specific guidance related to the attribution of compensation cost. This update is effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Company adopted this update effective January 1, 2019. It did not have a material impact on its financial position, results of operations or liquidity.

In December 2019, the FASB issued new guidance which amends certain aspects of accounting for income taxes. This amendment removes specific exceptions within existing GAAP related to the incremental approach for intraperiod tax allocation and to the general methodology for calculating income taxes in interim periods, among other changes. It also requires an entity to reflect the effect of an enacted change in tax laws or rates in the annual effective tax rate computation in the interim period that includes the enactment date, among other requirements. This amendment is effective for interim and annual periods beginning after December 15, 2020, and early adoption is permitted. The Company is continuing to evaluate the provisions of the amendment and has not determined the full impact on its consolidated financial statements and related disclosures.

Note 3—Impact of ASC 606 Adoption

ASC 606, *Revenue from Contracts with Customers*, requires the Company to identify the distinct promised goods and services within a contract which represent separate performance obligations and determine the transaction price to allocate to the performance obligations identified. The Company adopted ASC 606 using the modified retrospective method, which was applied to all existing contracts for which all (or substantially all) of the revenue had not been recognized under legacy revenue guidance as of January 1, 2019.

Royalty income from oil, natural gas and NGLs sales

Revenues from royalty properties are recorded under the cash receipts approach as directly received from the remitters' statement accompanying the revenue check. Since the revenue checks are generally received 30 to 90 days after the production month, the Company accrues for revenue earned but not received by estimating production volumes and product prices.

Lease bonus and other income

The Company also earns revenue from lease bonuses and delay rentals. The Company generates lease bonus revenue by leasing its mineral interests to exploration and production companies. A lease agreement represents the Company's contract with a customer and generally transfers the rights to any oil or natural gas discovered, grants the Company a right to a specified royalty interest, and requires that drilling and completion operations commence within a specified time period. Control is transferred to the lessee and the Company has satisfied its performance obligation when the lease agreement is executed, such that revenue is recognized when the lease bonus payment is received. The Company also recognizes revenue from delay rentals to the extent drilling has not started within the specified period, payment has been received, and the Company has no further obligation to refund the payment.

Allocation of transaction price to remaining performance obligations

Oil, natural gas and NGLs sales

The Company has utilized the practical expedient in ASC 606 which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. As the Company has determined that each unit of product generally represents a separate performance obligation, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Lease bonus and other income

Given that the Company does not recognize lease bonus or other income until a lease agreement has been executed, at which point its performance obligation has been satisfied, and payment is received, the Company does not typically record revenue for unsatisfied or partially unsatisfied performance obligations as of the end of the reporting period. Overall, there were no material changes in the timing of the satisfaction of the Company's performance obligations or the allocation of the transaction price to its performance obligations in applying the guidance in ASC 606 as compared to legacy U.S. GAAP.

Prior-period performance obligations

The Company records revenue in the month production is delivered to the purchaser. As a non-operator, the Company has limited visibility into the timing of when new wells start producing and production statements may not be received for 30 to 90 days or more after the date production is delivered. As a result, the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The expected sales volumes and prices for these properties are estimated and recorded within the Accounts receivable line item in the accompanying consolidated balance sheets. The difference between the Company's estimates and the actual amounts received for oil and natural gas sales is recorded in the period that payment is received from the third-party. For the year ended December 31, 2019, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was immaterial.

Note 4 – Transactions

On the Closing Date, Falcon completed the acquisition of the equity interests in the Royal Entities and in return the Contributors received (i) $400 million of cash and (ii) 40 million OpCo Common Units. The Company also issued to the Contributors 40 million shares of non-economic Class C Common Stock of the Company, which entitles each holder to one vote per share. The OpCo Common Units are redeemable on a one-for-one basis for shares of Class A Common Stock at the option of the Contributors. Upon the redemption by any Contributor of OpCo Common Units for Class A Common Stock, a corresponding number of shares of Class C Common Stock held by such Contributor will be cancelled.

In addition to the above, pursuant to the Contribution Agreement, Royal is entitled to receive earn-out consideration to be paid in the form of OpCo Common Units (and a corresponding number of shares of Class C Common Stock) if the 30-day volume-weighted average price ("30-Day VWAP") of the Class A Common Stock equals or exceeds certain hurdles set forth in the Contribution Agreement. Royal can potentially receive up to an additional 20.0 million OpCo Common Units as a part of the earn-out consideration. As of December 31, 2019, none of these hurdles have been met. Royal is also entitled to the earn-out consideration described above in connection with certain liquidity events of the Company, including a merger or sale of all or substantially all of the Company's assets, if the consideration paid to holders of the Class A Common Stock in connection with such liquidity event is greater than any of the 30-Day VWAP hurdles.

In connection with the Company's entry into the Contribution Agreement, the Company agreed to issue and sell in a private placement an aggregate of 11,480,000 shares of Class A Common Stock for a purchase price of $10.00 per share, and aggregate consideration of $114.8 million (the "Private Placement"). The Private Placement was consummated concurrently with the Closing Date and the proceeds of the Private Placement were used to fund a portion of the cash consideration paid to the Contributors.

Because Royal has effective control of the combined company after the Transactions through its majority voting interests in both the Company and, accordingly, Opco, the Transactions were accounted for as a reverse recapitalization. Although the Company was the legal acquirer, Royal was the accounting acquirer. As a result, the reports filed by the Company subsequent to the Transactions are prepared "as if" Royal is the predecessor and legal successor to the Company. The historical operations of Royal are deemed to be those of the Company. Thus, the financial statements included in this report reflect (i) the historical operating results of Royal prior to the Transactions; (ii) the combined results of the Company, OpCo and Royal following the Transactions; (iii) the assets, liabilities and partners' capital of Royal at their historical cost; and (iv) the Company's equity and earnings per share for the period from the Closing Date of the Transactions.

Below are amounts attributed to the disposition of the RNR interests included in discontinued operations in the consolidated statements of operations (in thousands):

	December 31, 2018	December 31, 2017
Revenues:		
Oil and gas sales	$ 5,401	$ 8,349
Expenses:		
Production and ad valorem taxes	484	738
Lease operating expenses	510	674
Transportation and marketing	333	421
Depreciation, depletion and amortization	1,574	3,248
General, administrative and other	324	237
Total expenses	3,225	5,318
Operating income		3,031
Other income (expense):		
Other income	2	-
Interest expense	(39)	(53)
Total other income (expense)	(37)	(53)
Net income	$ 2,139	$ 2,978

Below are the amounts attributed to the disposition of the RNR interests included in the consolidated cash flow statements (in thousands):

	December 31, 2018	December 31, 2017
Net cash provided by operating activities - discontinued operations	$ 4,488	$ 5,623
Net cash used in investing activities - discontinued operations	(523)	(3,293)

Note 5—Oil and Natural Gas Interests

Oil and natural gas interest include the following (in thousands):

	As of December 31, 2019	As of December 31, 2018
Oil and natural gas interests:		
Subject to depletion	$ 311,954	$ 307,438
Not subject to depletion	37,580	19,335
Gross oil and natural gas interests	349,534	326,773
Accumulated depletion and impairment	(130,342)	(117,605)
Oil and natural gas interests, net	$ 219,192	$ 209,168

In February 2018, Royal completed the sale of its interests in a portion of its oil and natural gas properties to an unaffiliated third-party for cash proceeds of $121.1 million. The sale resulted in a realized gain of $41.4 million. For the years ended December 31, 2019 and 2018, the Company has recorded approximately $0 million and $41.4 million in realized gains related to the sale of its interests in a portion of its oil and natural gas properties.

Note 6—Debt

Falcon Credit Facility

On the Closing Date, the Company entered into a credit facility with Citibank, N.A., as administrative agent and collateral agent for the lenders from time to time party thereto (the "Credit Facility"). The Credit Facility initially provides for a maximum credit amount of $500.0 million and a borrowing base based on its oil and natural gas reserves and other factors of $90 million, subject to scheduled semi-annual and other borrowing base redeterminations and expires on the fifth anniversary of the Closing Date. On the Closing Date, $38.0 million was drawn under the Credit Agreement to fund a portion of the purchase price of the Transactions, to pay transaction expenses, to fund any original issue discount or upfront fees in connection with the "market flex" provisions previously agreed upon and to finance working capital needs and other general corporate purposes. As of December 31, 2019, the Company had borrowings of $42.5 million under the Credit Facility at an interest rate of 4.05% and $47.5 million available for future borrowings under the Credit Facility. The Company incurred $3.2 million in connection with the closing of the Credit Facility. These amounts have been recorded as a deferred asset and will be amortized over the term of the Credit Facility. Unamortized deferred issuance costs were $2.4 million as of December 31, 2019.

Principal amounts borrowed are payable on the maturity date. The Company has a choice of borrowing at an alternative base rate (which is equal to the greatest of the federal funds rate plus one-half of 1.0%, the prime rate or the one-month LIBOR rate plus 1.0%) or LIBOR, with such borrowings bearing interest, payable quarterly in arrears for base rate loans and one month, two-month, three month or six-month periods for LIBOR loans. LIBOR loans bear interest at a rate per annum equal to the rate appearing on the Reuters Reference LIBOR01 or LIBOR02 page as the LIBOR, for deposits in dollars at 12:00 noon (London, England time) for one, two, three, or six months plus an applicable margin ranging from 200 to 300 basis points. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one-month LIBOR loans plus 1%, plus an applicable margin ranging from 100 to 200 basis points. The scheduled redeterminations of our borrowing base take place on April 1st and October 1st of each year.

Obligations under the Credit Facility are guaranteed by the Company and each of its existing and future, direct and indirect domestic subsidiaries (the "Credit Parties") and are secured by all the present and future assets of the Credit Parties, subject to customary carve-outs.

The Credit Facility contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, include restrictions on the Company's ability to incur additional indebtedness, acquire and sell assets, create liens, enter into certain lease agreements, make investments, make distributions and require the maintenance of the financial ratios described below.

Financial Covenant	**Required Ratio**
Ratio of total net debt to EBITDAX, as defined in the Credit Facility	Not greater than 4.0 to 1.0
Ratio of current assets to current liabilities, as defined in the Credit Facility	Not less than 1.0 to 1.0

As of December 31, 2019, the Company was in compliance with such covenants.

Note 7—Shareholder's Equity and Dividends

Shares Outstanding

Prior to the Transactions, Falcon was a special purpose acquisition company with no operations, formed as a vehicle to affect a business combination with one or more operating businesses. After the Closing of the Transactions, the Company became a holding company whose sole material operating asset consists of its interest in Royal through its interest in OpCo.

The following table summarizes the changes in outstanding stock and warrants during the year ended December 31, 2019.

	Class A Common Stock	**Class C Common Stock**	**Warrants**
Beginning Balance at December 31, 2018	45,855,000	40,000,000	21,249,999
Restricted stock grant vesting	108,716	-	-
Shares outstanding at December 31, 2019	45,963,716	40,000,000	21,249,999

Preferred stock - At December 31, 2019, there were no shares of preferred stock issued or outstanding. The Company is authorized to issue 1,000,000 shares of preferred stock with a par value of $0.0001 per share with such designation, rights and preferences as may be determined from time to time by the Company's Board of Directors.

Class A Common Stock - At December 31, 2019, there were 45,963,716 shares of Class A Common Stock issued and outstanding. Holders of the Company's Class A Common Stock are entitled to one vote for each share. The Company is authorized to issue 240,000,000 shares of Class A Common Stock with a par value of $0.0001 per share.

Class C Common Stock – At December 31, 2019, there were 40,000,000 shares of Class C Common Stock issued and outstanding. Class C common stock was issued to the Contributors in connection with the Transactions and are non-economic but entitled the holder to one vote per share. The Company is authorized to issue 120,000,000 shares of Class C Common Stock with a par value of $0.0001 per share.

Public Warrants – In July 2017, the Company consummated its initial public offering of units, each consisting of one share of Class A Common Stock and one-half of one warrant ("Public Warrant"). At December 31, 2019, there were 13,749,999 Public Warrants outstanding. Each Public Warrant entitles the holder to purchase one share of Class A Common Stock at the initial price of $11.50 per share. Pursuant to the Contribution Agreement, to the extent that any common stock dividend paid by the Company, when combined with other common stock dividends paid in the prior 365 days, exceeds $0.50 cents, it is categorized as an Extraordinary Dividend. Extraordinary Dividends reduce, penny for penny, the exercise price of the Company's warrants. For the quarters ending June 30, 2019 and September 30, 2019, the Company paid Extraordinary Dividends of $0.12 and $0.04, respectively. Accordingly, the exercise price of the Company's warrants was reduced to $11.38 after the Extraordinary Dividend paid for the quarter ended June 30, 2019 and was further reduced to $11.34 after the Extraordinary Dividend paid for the quarter ended September 30, 2019. There was no additional changes to the exercise price during the three months ended December 31, 2019. The Public Warrants will expire five years after the closing of the Transactions or earlier upon redemption or liquidation. The Company may call the Public Warrants for redemption, in whole and not in part, at a price of $0.01 per warrant with not less than 30 days' notice provided to the Public Warrant holders. However, this redemption right can only be exercised if the last sale price of the Class A Common Stock equals or exceeds $18.00 per share for any 20 trading days within a 30-day trading period ending three business days before we send the notice of redemption to the Public Warrant holders.

Private Placement Warrants –Upon closing of the Osprey initial public offering, the Sponsor purchased an aggregate of 7,500,000 warrants at a price of $1.00 per warrant (the "Private Placement Warrants). Each Private Placement Warrant is exercisable for one share of Class A Common Stock at a price of $11.34. The Private Placement Warrants are identical to the Public Warrants discussed above, except (i) they will not be redeemable by the Company so long as they are held by the Sponsor and (ii) they may be exercisable by the holders on a cashless basis. At December 31, 2019, there were 7,500,000 Private Placement Warrants outstanding.

In connection with the Transactions, the Company issued 40,000,000 OpCo Common Units to the Contributors. The OpCo Common Units are redeemable on a one-for-one basis for shares of Class A Common Stock at the option of the holder. Upon the redemption by any Contributor of OpCo Common Units for shares of Class A Common Stock, a corresponding number of shares of Class C Common Stock held by such Contributor will be cancelled.

Earn-Out

In addition to the above, the Contributors will be entitled to receive earn-out consideration to be paid in the form of OpCo Common Units (with a corresponding number of shares of Class C Common Stock) if the volume-weighted average price of the trading days during any thirty (30) calendar days (the "30-Day VWAP") of the Class A Common Stock equals or exceeds certain hurdles set forth in the Contribution Agreement. If the 30-Day VWAP of the Class A Common Stock is $12.50 or more per share at any time within the seven years following the closing, Royal LP will receive (i) an additional 10 million OpCo Common Units (and an equivalent number of shares of Class C Common Stock), plus (ii) an amount of OpCo Common Units (and an equivalent number of shares of Class C Common Stock) equal to (x) the amount by which annual cash dividends paid on each share of Class A Common Stock exceeds $0.50 in each year between the closing and the date the first earn-out is achieved (with any dividends paid in the stub year in which the first earn-out is achieved annualized for purposes of determining what portion of such dividends would have, on an annual basis, exceeded $0.50), multiplied by 10 million, (y) divided by $12.50. If the 30-Day VWAP of the Class A Common Stock is $15.00 or more per share at any time within the seven years following the closing (which $15.00 threshold will be reduced by the amount by which annual cash dividends paid on each share of Class A Common Stock exceeds $0.50 in each year between the closing and the date the earn-out is achieved, but not below $12.50), the Contributors will receive an additional 10 million OpCo Common Units (and an equivalent number of Class C Common Stock). Upon recognition of the earn-out, as there is no consideration received, the Company would record the payment of the earn-out as adjustments through equity (non-controlling interest and additional-paid-in-capital).

Private Placement

In connection with the Company's entry into the Contribution Agreement, the Company agreed to issue and sell in a private placement an aggregate of 11,480,000 shares of Class A Common Stock for a purchase price of $10.00 per share, and aggregate consideration of $114.8 million (the "Private Placement"). The Private Placement was consummated concurrently with the Closing Date and the proceeds of the Private Placement were used to fund a portion of the cash consideration paid to the Contributors.

Noncontrolling Interest

The Company owns 100% of the general partner interests and 53% of the limited partner interests of OpCo and due to the Company's controlling interest in OpCo, OpCo is a consolidated subsidiary of the Company. Non-controlling ownership interests in OpCo are presented in the consolidated balance sheet within shareholders' equity as a separate component. In addition, consolidated net income includes earnings attributable to both the shareholders and the non-controlling interests. For the years ended December 31, 2019 and 2018, $27.7 million and $4.1 million, respectively, of distributions for each period have been made to non-controlling interest holders of the consolidated subsidiaries.

Cash Dividends

The table below summarizes the quarterly dividends related to the Company's quarterly financial results (in thousands, except per unit data):

Quarter Ended	Total Quarterly Dividend Per Share	Total Cash Dividends	Payment Date	Shareholders Record Date
December 31, 2019	$ 0.1350	$ 6,205	March 9, 2020	February 25, 2020
September 30, 2019	$ 0.1350	$ 6,203	December 3, 2019	November 20, 2019
June 30, 2019	$ 0.1500	$ 6,879	September 6, 2019	August 26, 2019
March 31, 2019	$ 0.1750	$ 8,026	May 29, 2019	May 17, 2019
December 31, 2018	$ 0.2000	$ 9,171	February 28, 2019	February 21, 2019
September 30, 2018[(1)]	$ 0.0950	$ 4,356	November 15, 2018	November 8, 2018

(1) Initial pro rata dividend, prorated for the period from August 23, 2018 to September 30, 2018.

Note 8—Share-Based Compensation

In connection with the Closing, the Falcon Board of Directors adopted the Falcon Minerals Corporation 2018 Long-Term Incentive Plan (the "Plan"). An aggregate of 8.6 million shares of Class A Common Stock are available for issuance under the Plan. The Plan provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units and other stock-based awards. Common shares that are cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. Distribution equivalent rights ("DER") are also available for grant under the Plan, either alone or in tandem with other specific awards, which will entitle the recipient to receive an amount equal to dividends paid on a Class A common share. The Plan is administered by the Falcon Board of Directors or a committee thereof.

Restricted Stock Grants

In accordance with the Plan, the Falcon Board of Directors is authorized to issue restricted stock awards ("RSA") to eligible employees and directors. The Company estimates the fair value of the RSAs as the closing price of the Company's Class A Common Stock on the grant date of the award, which is expensed over the applicable vesting period. Each RSA that has been granted has a DER included in each agreement. Dividends paid in connection with the DERs are accounted for as a reduction in retained earnings for those awards that are expected to vest. RSAs that are forfeited could cause a reclassification of any previously recognized DER payments from a reduction in retained earnings to additional compensation cost.

Performance Stock Units

Under the Plan, the Falcon Board of Directors is authorized to issue performance stock units ("PSU") to eligible employees and directors. The Company estimates the fair value and the derived service period of the PSUs utilizing a lattice model since the vesting requirements are a market-based condition (indexed to the Falcon stock price). The Company engaged a third-party consultant to calculate fair value and the derived service period of the grants at the time of issuance. The fair value of the PSUs is then amortized over the longer of the service condition or the derived service period attributable to each grant. All compensation cost for the PSUs will be recognized over the longer of the service condition or the derived service period, even if the market-condition is never satisfied as long as the award is not forfeited. The PSUs that have been granted to date do not have any DERs included in the agreements. PSUs that are forfeited could cause a reclassification of any previously recognized DER payments from a reduction in retained earnings to additional compensation cost.

The following table summarizes the activity in our unvested RSAs and PSUs for the year ended December 31, 2019:

	Restricted Stock	Weighted Average Grant-Date Fair Value	Performance Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2018	-		-	
Granted	419,640	$ 8.14	1,413,334	$ 3.45
Vested	(110,598)	$ 8.27	-	$ -
Forfeited	(25,125)	$ 7.97	-	$ -
Unvested at December 31, 2019	283,917	$ 8.10	1,413,334	$ 3.45

For the year ended December 31, 2019, the Company incurred $2.5 million of share-based compensation which is included in general, administrative and other expenses in the accompanying consolidated statements of operations. The Company did not have any restricted shares granted until 2019 and therefore the Company did not incur any related expenses in the prior year. The unamortized estimated fair value of unvested RSAs and PSUs was $5.5 million at December 31, 2019. These costs are expected to be recognized as expense over a weighted average period of 1.9 years. In addition, for the year ended December 31, 2019, the Company paid $0.2 million related to DERs of RSA holders.

Note 9—Earnings Per Share

The Transactions were structured as a reverse capitalization by which the Company issued stock for the net assets of Royal accompanied by a recapitalization. Earnings per share is calculated for the Company only for periods after the Transactions due to the reverse recapitalization.

Earnings per share is computed using the two-class method. The two-class method determines earnings per share of common stock and participating securities according to dividends or dividend equivalents and their respective participation rights in undistributed earnings. Participating securities represent restricted stock awards in which the recipients have non-forfeitable rights to dividend equivalents during the performance period.

The following table sets forth the calculation of basic and diluted earnings per share for the periods indicated (in thousands, except per share data):

	For the Year Ended December 31,			
		2019		2018
Numerator:				
Net income attributable to common stockholders - basic and diluted	$	14,350		9,166
Less: Earnings allocated to participating securities		(115)		-
	$	14,235	$	9,166
Denominator:				
Weighted average shares outstanding - basic and diluted		45,893		45,855
Net income per common share, basic and diluted	$	0.31	$	0.20

The Company had the following shares that were excluded from the computation of diluted earnings per share because their inclusion would have been anti-dilutive for the periods presented but could potentially dilute basic earnings per share in future periods (in thousands):

	For the Year Ended December 31,	
	2019	2018
Warrants	21,250	21,250
Class C common shares	40,000	40,000
Total	61,250	61,250

Diluted net income per share also excludes the effects of OpCo Common Units (and related Class C Common Stock) associated with the earn-out, which are convertible into Class A Common Stock, and the PSUs because each are considered contingently issuable shares and the conditions for issuance were not satisfied as of December 31, 2019.

Note 10—Income Taxes

The Company under ASC 740 uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (i) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (ii) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

For the years ended December 31, 2019 and 2018, the Company recorded an income tax expense of $3.9 million and $3.3 million, respectively. Royal was historically treated as a partnership for federal income tax purposes, with each partner being separately taxed on its share of taxable income; therefore, there is no federal income tax expense reflected in Royal's financial statements for any period prior to the Transactions on August 23, 2018.

As of December 31, 2019 and 2018, the Company had $56.4 million and $58.8 million, respectively, of net deferred tax assets. These net deferred tax assets relate to oil and gas assets and other temporary items where the tax basis differs from the GAAP carrying amounts.

At December 31, 2019 and 2018, the Company had recorded a prepayment of income taxes of $0.5 million and $0.8 million, respectively.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as income tax expense. No amounts were accrued for the payment of interest and penalties at December 31, 2019. The Company is currently not aware of any issues under review that could result in significant payments, accruals or material deviation from its position. The Company is subject to income tax examinations by major taxing authorities since inception.

The components of the provision for income taxes for the years ended December 31, 2019 are as follows:

	For the Year Ended December 31, 2019	2018
	(in thousands)	
Current income tax provision:		
Federal	$ 1,459	$ 995
State	38	12
Total current income tax provision	1,497	1,007
Deferred income tax provision:		
Federal	2,399	2,264
State	22	21
Total deferred income tax provision	2,421	2,285
Total provision for income taxes	$ 3,918	$ 3,292

A reconciliation of the statutory federal income tax amount to the recorded expense is as follows:

	For the Year Ended December 31, 2019	2018
	(in thousands)	
Income tax expense at the federal statutory tax rate (21%)	$ 7,315	$ 21,475
Impact of net income attributable to the non-controlling interests	(3,478)	(2,306)
State taxes, net of federal benefit	47	-
Impact of net income attributable to pre-business combination period	-	(16,576)
Impact of pre-business combination tax adjustment	-	824
Other, net	34	(125)
Provision for (benefit from) income taxes	$ 3,918	$ 3,292

The components of the Company's deferred tax assets and liabilities as of December 31, 2019 and 2018 are as follows:

	For the Year Ended December 31, 2019	2018
	(in thousands)	
Deferred tax assets:		
Difference in carrying value and tax basis in oil and gas assets	$ 56,057	$ 59,208
Share-based compensation	394	-
Prior period income tax benefit/(liability)	-	(370)
Total deferred tax assets	56,451	58,838
Valuation allowance	-	-
Net deferred tax assets	56,451	58,838
Deferred tax liabilities:		
Prepaid Expenses	99	65
Net deferred tax assets	$ 56,352	$ 58,773

Note 11—Related Party Transactions

Founder Shares

In June 2016, the Company issued an aggregate of 125,000 shares of Class B Common Stock to Osprey Sponsor, LLC (the "Sponsor") for an aggregate purchase price of $25,000 (the "Founder Shares"). In March 2017, the Company effectuated a 57.5-for-1 stock split resulting in an aggregate of 7,187,500 Founder Shares outstanding and held by the Sponsor. The Founder Shares automatically converted into Class A Common Stock upon the consummation of the Transactions on a one-for-one basis. Due to the underwriter's election not to exercise the remaining portion of the over-allotment option related to the Osprey initial public offering, 312,500 Founder Shares were forfeited resulting in an aggregate of 6,875,000 Founder Shares held by the Sponsor prior to the Transactions.

Atlas Energy Group, LLC

Atlas Energy Group, LLC, which Company officers and directors Edward Cohen and Jonathan Cohen are also directors and officers of, and its affiliates provide the Company with advisory services in connection with potential business opportunities and prospective targets. For the years ended December 31, 2019 and 2018, the Company paid less than $0.1 million for each period in expenses in connection with such services. In October 2018, Daniel Herz resigned from any and all director and officer positions within Atlas Energy Group, LLC and its affiliates.

Hepco Capital Management, LLC

Hepco Capital Management, LLC ("Hepco Capital"), which Company officers and directors Edward Cohen, Jonathan Cohen and Jeffrey Brotman are also directors and officers of, and its affiliates share certain employees and office space and reimburses the Company for a proportionate amount of the shared expenses on a monthly basis. For the years ended December 31, 2019 and 2018, the Company received $0.3 million and less than $0.1 million, respectively.

Royal Resources L.P.

Royal Resources L.P. ("Royal"), which owns 35.2 million shares of the Class C Common Stock of the Company, as well as, 35.2 million units of OpCo, has entered into a Master Service Agreement ("MSA") with the Company in December 2018. Under the MSA, the Company provides certain management services to Royal. For the years ended December 31, 2019 and 2018, the Company received $0.6 million and less than $0.1 million under this agreement.

Note 12—Major Operators

The following table presents the percentage of revenues with the Company's significant operators (those that have accounted for 10% or more of the Company's revenues in a given period) for the periods indicated:

	% of Revenues For the Year Ended December 31,		
	2019	2018	2017
Conoco Phillips	33%	39%	15%
EOG	29%	22%	18%
Devon	18%	16%	30%
BP	3%	5%	20%
Total	83%	82%	83%

Note 13—Commitments and Contingencies

The Company could be subject to various possible loss contingencies which arise primarily from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry. Such contingencies include differing interpretations as to the prices at which natural gas and crude oil sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Management believes it has complied with the various applicable laws and regulations, administrative rulings and interpretations.

Commitments and Contractual Obligations

Future non-cancelable commitments related to certain contractual obligations as of December 31, 2019 are presented below (in thousands):

	Payments Due by Period						
	Total	2020	2021	2022	2023	2024	Thereafter
Long-term debt obligations	$ 42,500	$ -	$ -	$ -	$ 42,500	$ -	$ -
Operating lease obligations	992	309	311	121	106	108	37
Total	$ 43,492	$ 309	$ 311	$ 121	$ 42,606	$ 108	$ 37

Note 14—Subsequent Events

Cash Dividends

In February 2020, the Company declared a quarterly cash dividend of $0.135 per share of Class A Common Stock totaling approximately $6.2 million for all shares of Class A Common Stock outstanding. The dividend is for the period from October 1, 2019 through December 31, 2019. The dividend was payable on March 9, 2020 to all Class A shareholders of record on February 25, 2020.

OpCo Distribution

In March 2020, OpCo made distributions totaling $11.6 million to its unitholders. Of the $11.6 million distributed by OpCo, the Company received $6.2 million.

Note 15 – Quarterly Financial Data (Unaudited)

(in thousands, except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2019:				
Revenues	$ 21,258	$ 18,246	$ 15,908	$ 13,051
Operating income	$ 13,331	$ 10,776	$ 8,081	$ 4,968
Net income attributable to common shareholders	$ 5,382	$ 3,756	$ 2,884	$ 2,328
Net income per share:				
Common shares, basic and diluted	$ 0.12	$ 0.08	$ 0.06	$ 0.05
Weighted average number of shares outstanding:				
Common shares, basic and diluted	45,856	45,858	45,899	45,956

(in thousands, except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2018:				
Revenues	$ 20,303	$ 26,313	$ 24,282	$ 26,301
Operating income	$ 12,230	$ 16,299	$ 16,837	$ 17,816
Net income attributable to common shareholders/unitholders	$ 53,866	$ 16,956	$ 12,667	$ 6,636
Net income per share:				
Common shares, basic and diluted (2)	N/A	N/A	$ 0.06 (1)	$ 0.14
Weighted average number of shares outstanding:				
Common shares, basic and diluted (2)	N/A	N/A	45,855	45,855

(1) Subsequent to the issuance of the Company's Quarterly Report on Form 10-Q for the three and nine months ended September 30, 2018, the Company's management determined that net income attributable to non-controlling interests, net of tax, had been excluded from the numerator in the calculation of Earnings per common share (diluted). As a result, Earnings per common share (diluted) for the three months ended September 30, 2018 has been corrected from $0.03 previously reported to $0.06.

(2) Since the Transactions were structured as a reverse capitalization by which the Company issued stock for the net assets of Royal accompanied by a recapitalization earnings per share is calculated for the Company only for periods after the Transactions due to the reverse recapitalization.

Note 16 – Supplemental Information on Oil and Natural Gas Operations (Unaudited)

The Company’s oil and natural gas reserves are attributable solely to properties within the United States. Discontinued operations information comprising of the RNR interests which were not acquired in the Transactions have not been included in the Supplemental Information for Crude Oil Producing Activities for each period presented below.

Capitalized oil and natural gas costs

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion and amortization are as follows:

	As of December 31, 2019	2018
	(in thousands)	
Proved royalty interest	$ 311,954	$ 307,438
Unproved royalty interests	37,580	19,335
Accumulated amortization	(130,342)	(117,605)
Net royalty interests in oil and natural gas properties	$ 219,192	$ 209,168

Costs incurred in oil and natural gas activities

Costs incurred in oil and natural gas property acquisitions, exploration and development activities are as follows:

	December 31, 2019	2018	2017
	(in thousands)		
Acquisition costs:			
Proved properties	$ 4,011	$ 207	$ -
Unproved properties	18,750	1,008	-
Total	$ 22,761	$ 1,215	$ -

Results of operations from oil and natural gas producing activities

The following table sets forth the revenues and expenses related to the production and sale of oil and natural gas. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to the net operating results of the Company's oil, natural gas and natural gas liquids operations.

	December 31,		
	2019	2018	2017
		(in thousands)	
Royalty income	$ 68,463	$ 98,655	$ 95,972
Production and ad valorem taxes	(4,262)	(5,143)	(5,242)
Marketing and transportation	(2,396)	(2,368)	(6,505)
Depletion	(12,737)	(16,962)	(33,837)
Income tax expense	(3,918)	(3,292)	-
Results of operations from oil, natural gas and natural gas liquids	$ 45,150	$ 70,890	$ 50,388

Oil and Natural Gas Reserves

Proved oil and gas reserve estimates as of December 31, 2019, 2018 and 2017 were prepared by Ryder Scott Company, L.P. independent petroleum engineers. Proved reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions based upon the 12-month unweighted average of the first-day-of-the-month prices.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

The changes in estimated proved reserves are as follows:

	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total (MBOE)
Proved Developed and Undeveloped Reserves:				
As of December 31, 2016	12,902	33,235	3,566	22,007
Extensions and discoveries	1,581	5,194	431	2,878
Revisions of previous estimates	6,227	28,574	1,428	12,417
Divestiture of reserves	(1,228)	(3,767)	(582)	(2,438)
Production	(1,406)	(4,446)	(525)	(2,672)
As of December 31, 2017	18,076	58,790	4,318	32,192
Purchase of reserves in place	23	83	13	50
Extensions and discoveries	-	-	-	-
Revisions of previous estimates	421	7,514	86	1,759
Divestiture of reserves	(2,150)	(6,155)	(969)	(4,145)
Production	(1,158)	(4,047)	(285)	(2,117)
As of December 31, 2018	15,212	56,185	3,163	27,740
Purchase of reserves in place	32	70	12	56
Extensions and discoveries	215	553	71	378
Revisions of previous estimates	(1,984)	(6,950)	(230)	(3,373)
Production	(879)	(3,588)	(297)	(1,774)
As of December 31, 2019	12,596	46,270	2,719	23,027
Proved Developed Reserves				
December 31, 2017	5,344	20,043	1,705	10,390
December 31, 2018	3,857	18,700	1,293	8,267
December 31, 2019	3,900	18,016	1,230	8,133
Proved Undeveloped Reserves:				
December 31, 2017	12,732	38,747	2,613	21,803
December 31, 2018	11,355	37,485	1,870	19,473
December 31, 2019	8,696	28,254	1,489	14,894

Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

During the year ended December 31, 2019, the Company’s negative revisions of previous estimates of 3,373 MBoe resulted primarily from reducing the existing PUD locations by 314 wells due to a change in development timing and lower commodity prices. The purchase of reserves in place of 56 MBoe were due to multiple acquisitions located within the Eagle Ford Shale.

During the year ended December 31, 2018, the Company’s positive revisions of previous estimates of 1,759 MBoe resulted primarily from the drilling of 92 new wells and from 225 new proved undeveloped locations added. The purchase of reserves in place of 50 MBoe were due to multiple acquisitions primarily located in Karnes county within the Eagle Ford Shale.

During the year ended December 31, 2017, the Company’s extensions and discoveries of 2,878 MBoe resulted primarily from the drilling of 93 new wells and from 85 new proved undeveloped locations added. The Company’s positive revisions of previous estimated quantities of 12,417 MBoe were primarily due to development timing and higher product pricing.

Standardized Measure of Discounted Cash Flows

The standardized measure of discounted future net cash flows are based on the unweighted average, first-day-of-the-month price. The projections should not be viewed as realistic estimates of future cash flows, nor should the “standardized measure” be interpreted as representing current value to the Company. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary.

The following table sets forth the standardized measure of discounted future net cash flows attributable to the Company's proved oil and natural gas reserves as of December 31, 2019, 2018 and 2017:

	December 31,		
	2019	2018	2017
	(in thousands)		
Future cash inflows	$ 882,076	$ 1,265,153	$ 1,158,687
Future production costs	(70,956)	(98,672)	(116,121)
Future income tax expense	(48,040)	(87,803)	-
Future net cash flows	763,080	1,078,678	1,042,566
10% discount to reflect timing of cash flows	(304,730)	(469,808)	(446,987)
Standardized measure of discounted cash flows	$ 458,350	$ 608,870	$ 595,579

In the table below the average first-day-of–the-month price for oil, natural gas and natural gas liquids is presented, all utilized in the computation of future cash inflows:

	December 31,		
	2019	2018	2017
	Unweighted Arithmetic Average First-Day-of-the-Month Prices		
Oil (per Bbl)	$ 55.69	$ 65.56	$ 51.34
Natural gas (per Mcf)	$ 2.58	$ 3.10	$ 2.98
Natural gas liquids (per Bbl)	$ 13.37	$ 25.57	$ 19.51

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved reserves are as follows:

	December 31,		
	2019	2018	2017
	(in thousands)		
Standardized measure of discounted future net cash flows at the beginning of the period	$ 608,870	$ 595,579	$ 326,399
Purchase of minerals in place	1,256	1,092	-
Sales of oil and natural gas, net of production costs	(59,949)	(91,180)	(84,225)
Extensions and discoveries	9,711	-	53,076
Net changes in prices and production costs	(91,386)	165,659	68,978
Revisions of previous quantity estimates	(92,479)	41,728	260,567
Divestiture of reserves	-	(73,755)	(42,821)
Net changes in income taxes	20,613	(49,758)	-
Accretion of discount	65,863	59,558	32,640
Net changes in timing of production and other	(4,149)	(40,053)	(19,035)
Standardized measure of discounted future net cash flows at the end of the period	$ 458,350	$ 608,870	$ 595,579

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Our Directors and Executive Officers

Non-Director Principal Officers

Daniel C. Herz
Chief Executive Officer and President

Bryan C. Gunderson
Chief Financial Officer

Jeffrey F. Brotman
Chief Legal Officer and Secretary

Michael J. Downs
Chief Operating Officer

Stephen J. Pilatzke
Chief Accounting Officer

Directors

William D. Anderson
Managing Partner of Anderson King Energy Consultants, LLC

Edward E. Cohen
Vice Chairman of the Board of Directors; Chief Executive Officer of Atlas Energy Group, LLC

Jonathan Z. Cohen
Chairman of the Board of Directors; Chairman, Chief Executive Officer and Founder of Hepco Capital Management

Brian L. Frank
Managing Partner of Declaration Partners LP

Jonathan R. Hamilton
Senior Associate in the Private Equity Group at Blackstone

Alan J. Hirshberg
Senior Advisor at Blackstone

Adam M. Jenkins
Managing Director in the Private Equity Group at Blackstone

Steven R. Jones
Executive Vice President and Chief Financial Officer of WaterBridge Resources LLC

Eric Liaw
Senior Managing Director in the Private Equity Group at Blackstone

Stock Listing
Falcon Minerals Corporation Class A common stock and warrants are listed on the Nasdaq Capital Market under the symbols "FLMN" and "FLMNW," respectively.

Transfer Agent and Registrar
Continental Stock Transfer & Trust
1 State Street, 30th Floor
New York, NY 10004-1561
212-509-4000
Email: cstmail@continentalstock.com
Website: www.continentalstock.com

Annual Report on Form 10-K
Falcon's Annual Report on Form 10-K for the year ended December 31, 2019 is included in this annual report. The exhibits accompanying the report are filed with the Securities and Exchange Commission and may be accessed in the EDGAR database at the Securities and Exchange Commission's website, www.sec.gov, or through Falcon's website in the "Investors" section at www.falconminerals.com. We will provide these items to stockholders upon request. Requests for any such exhibits should be made to:

Falcon Minerals Corporation
Attn: Jeffrey F. Brotman, Secretary
1845 Walnut Street, Suite 1111
Philadelphia, PA 19103
Telephone: (212) 506-5925

Annual Meeting of Stockholders
Stockholders of Falcon Minerals Corporation are cordially invited to attend the 2020 Annual Meeting of Stockholders scheduled to be held on May 28, 2020 at 11:30 A.M. at 510 Madison Avenue, 8th Floor, New York, NY 10022.*

Forward Looking Statements
In accordance with the Private Securities Litigation Reform Act of 1995, Falcon Minerals Corporation notes that this annual report contains forward-looking statements that involve risks and uncertainties, including those relating to its future success and growth. Actual results may differ materially due to risks and uncertainties described in Falcon's filings with the U.S. Securities and Exchange Commission. Falcon does not intend to update these forward-looking statements except as required by law.

Independent Registered Public Accounting Firm
Deloitte & Touche LLP

Investor Relations Contact
Email: IR@falconminerals.com

*We intend to hold our annual meeting in person. However, we are actively monitoring the public health and travel concerns of our stockholders, directors and employees in light of COVID-19 (Coronavirus), as well as the related protocols that federal, state and local governments may impose. As part of our precautions, we are considering the possibility of changing the location of the annual meeting and/or holding a virtual meeting by means of remote communication. We will announce any alternative arrangements for the annual meeting as promptly as practicable.