Falcon Minerals

Annual Report to Shareholders

For the Year Ended December 31, 2020

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

FORM 10-K/A

(Amendment No. 1)

(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, 2020

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(s)	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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal controls over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

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 30, 2020, 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 $157.1 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. The registrant does not have any non-voting common stock outstanding.

As of March 4, 2021, there were 46,107,183 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 2021 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;
- changes in general economic conditions, including the material and adverse negative consequences of the COVID-19 pandemic and its unfolding impact on the global and national economy;
- the actions of the Organization of Petroleum Exporting Countries (OPEC) and other significant producers and governments;
- 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;
- risk related to our hedging activities;
- 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: One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

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 BOE.

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 net 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 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.

EXPLANATORY NOTE

General

On May 4, 2021, the Audit Committee (the "Audit Committee") of the Board of Directors and in consultation with management, concluded that its audited consolidated financial statements for the years ended December 31, 2020, 2019 and 2018, and the interim period within those years, could no longer be relied upon as a result of material accounting errors identified by management.

Restatement

We are filing this Annual Report on Form 10-K/A to amend our Annual Report on Form 10-K for the year ended December 31, 2020, which was originally filed with the Securities and Exchange Commission ("SEC") on March 12, 2021 (the "Original Form 10-K"). This Annual Report on Form 10-K/A speaks as of the date of the Original Form 10-K and has not been updated to reflect events occurring subsequent to the filing of the Original Form 10-K other than those associated with the restatement of our consolidated financial statements.

For the convenience of the reader, this Annual Report on Form 10-K/A amends and restates the Original Form 10-K in its entirety. As a result, it includes both items that have been changed as a result of the restatement and items that are unchanged from the Original Form 10-K.

Restatement Background

As a result of management's evaluation of the "Staff Statement on Accounting and Reporting Considerations for Warrants Issued by Special Purpose Acquisition Companies" issued by the SEC on April 12, 2021 (the "Staff Statement"), it was determined that the Company's 13,750,000 warrants issued in connection with their initial public offering ("IPO") in July 2017 ("Public Warrants") and the Company's 7,500,000 warrants issued post IPO in August 2017 ("Private Placement Warrants"), collectively ("Warrants") should have been recorded as liabilities instead of equity, which caused the Company's liabilities and net income (loss) to be misstated by the resulting changes in valuation to the warrant liabilities.

As a result of the process above, management performed a quarterly valuation analysis of the Warrants since the grant date of each type of warrant. The resulting analysis was utilized to calculate the restatement impact for the years ended December 31, 2020, 2019 and 2018 and for the quarterly periods in 2020 and 2019.

Restatement of Previously Issued Consolidated Financial Statements

As described above, this Annual Report on Form 10-K/A includes audited restated consolidated financial statements as of December 31, 2020 and 2019 and for the years ended December 31, 2020, 2019 and 2018. See Note 3, Restatement of Previously Issued Consolidated Financial Statements, in Item 15. Exhibits and Financial Statement Schedules, for additional information.

The restatement impact affected previously reported net income and basic and diluted earnings per share (in thousands, except per share data) as follows:

	December 31, 2020		
	As Previously Reported	Adjustments	As Restated
Net income attributable to shareholders'	$ 2,572	$ 5,128	$ 7,700
Earnings per share - basic	$ 0.05	$ 0.12	$ 0.17
Earnings per share - diluted	$ 0.05	$ 0.06	$ 0.11

	December 31, 2019		
	As Previously Reported	Adjustments	As Restated
Net income attributable to shareholders'	$ 14,350	$ 6,069	$ 20,419
Earnings per share - basic	$ 0.31	$ 0.13	$ 0.44
Earnings per share - diluted	$ 0.31	$ 0.08	$ 0.39

	December 31, 2018		
	As Previously Reported	Adjustments	As Restated
Net income attributable to shareholders'	$ 90,125	$ 27,800	$ 117,925
Earnings per share - basic	$ 0.20	$ 0.61	$ 0.81
Earnings per share - diluted	$ 0.20	$ 0.33	$ 0.53

Control Considerations

In connection with the restatement, management has reassessed its conclusions regarding the effectiveness of our internal control over financial reporting as of December 31, 2020 and has determined that a material weakness in our internal controls over financial reporting existed as of that date. As a result of the material weakness, our disclosure controls and procedures were not effective as of December 31, 2020. Management will be implementing changes to strengthen our internal controls and remediate the material weakness. See Item 9A, Controls and Procedures, for additional information related to the material weakness in internal controls over financial reporting and our related remediation activities.

In accordance with applicable SEC rules, this Annual Report on Form 10-K/A includes new certifications required by Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 from our Chief Executive Officer (as Principal Executive Officer) and our Chief Financial Officer (as Principal Financial Officer) dated as of the filing date of this Annual Report on Form 10-K/A.

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 that 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 year ended December 31, 2018, 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, 2020, 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. In addition, our assets include Royalties related to approximately 80,000 gross unit acres in the Appalachian region, including Pennsylvania, West Virginia, and Ohio. Our acreage was extensively delineated by 2,486 producing wells as of December 31, 2020, of which 2,087 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 4,566 BOE/d (50% oil) for the year ended December 31, 2020. This includes Eagle Ford production of 4,033 BOE/d (56% 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 87% 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, 2020, our revenues were derived 75% from oil and condensate sales, 18% from natural gas liquid sales and 7% from natural gas sales. For the year ended December 31, 2019 our revenues were derived 77% from oil and condensate sales, 14% from natural gas liquid sales, 7% from natural gas sales and 2% from lease bonuses. 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 from time to time the Company may utilize commodity derivative instruments to mitigate the given price risk associated with its operations.

Our Properties

Our assets consist of Royalties related to 541 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, 2020, these interests entitled us to receive an average royalty of 1.27% from the producing wells on the acreage underlying our Royalties, with no additional future capital or operating expenses required. As of December 31, 2020, there were 2,486 wells producing on this acreage, and average net production for the year ended December 31, 2020 was approximately 4,566 BOE/d. In addition, there were 160 horizontal wells in various stages of completion. As of December 31, 2020, there were 148 additional permits outstanding for undrilled wells or wells currently being drilled on the acreage underlying our Royalties.

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 that 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 nine 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

The reserves estimates as of December 31, 2020 and 2019, shown herein, have been independently evaluated by Ryder Scott Company, L.P. (“RSC”). RSC was founded in 1937 and for over 80 years has provided worldwide services to the petroleum industry including but not limited to the issuance of reserve reports and audits, appraisals of oil and gas properties, enhanced recovery services, expert witness testimony, and management services under the Texas Board of Professional Engineers Registration No. F-1580. Within RSC, the technical person primarily responsible for preparing the estimates set forth in the RSC summary reserves report incorporated herein was Ali A. Porbandarwala, P.E. Mr. Porbandarwala, a Licensed Professional Engineering in the State of Texas (License No. 107652) has been practicing consulting petroleum engineering at RSC since 2008 and has over five years of prior industry experience. Mr. Porbandarwala earned a Bachelor of Science degree in Chemical Engineering from The University of Kansas in 2001 and a Masters in Business Administration from The University of Texas at Austin in 2007 and is a licensed Professional Engineer in the State of Texas. As technical principal, Mr. Porbandarwala meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum

Engineers and is proficient in judiciously applying industry standard practices to engineering evaluations as well as applying SEC and other industry reserves definitions and guidelines. RSC does not own an interest in us or any of our properties, nor is it employed by us on a contingent basis. A copy of RSC's estimated proved reserve report as of December 31, 2020 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, 2020 and 2019 were prepared by RSC. 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.

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, 2020 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, RSC 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 14 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, 2020 and 2019 based on the reserve reports prepared by RSC. 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,	
	2020	**2019**
Estimated proved developed reserves:		
Oil (MBbls)	3,291	3,900
Natural gas (MMcf)	19,755	18,016
Natural gas liquids (MBbls)	1,164	1,230
Total (MBOE) (1)	7,747	8,133
Estimated proved undeveloped reserves:		
Oil (MBbls)	6,451	8,696
Natural gas (MMcf)	28,781	28,254
Natural gas liquids (Bbls)	1,022	1,489
Total (MBOE) (1)	12,270	14,894
Estimated net proved reserves:		
Oil (MBbls)	9,742	12,596
Natural gas (MMcf)	48,536	46,270
Natural gas liquids (MBbls)	2,186	2,719
Total (MBOE) (1)	20,017	23,027
Percent proved developed	38.70%	35.32%
PV-10 of proved reserves (in millions) (2)	$ 255.5	$ 487.5

(1) Estimates of reserves as of December 31, 2020 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, 2020 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 $39.57 per Bbl for oil and $1.99 per Mcf for natural gas at December 31, 2020. The unweighted arithmetic average first day of the month prices were $55.69 per Bbl for oil and $2.58 per Mcf 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. 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, 2020, our historical proved developed reserves totaled 3,291 MBbls of oil, 19,755 MMcf of natural gas and 1,164 MBbls of natural gas liquids, for a total of 7,747 MBOE. Of the total proved developed reserves, 91% are producing and the remaining 9% 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, 2020, our historical proved undeveloped reserves totaled 6,451 MBbls of oil, 28,781 MMcf of natural gas and 1,022 MBbls of natural gas liquids, for a total of 12,270 MBOE. PUD reserves will be converted from undeveloped to developed as the applicable wells begin production.

During the year ended December 31, 2020, our PUD reserves changed due to:

- the conversion of 851 MBOE of PUD reserves into PDP and PNP reserves;
- net negative revisions of 2,646 MBOE as a result of the removal of certain locations to the drilling schedule as part of a revised development plan;
- negative revisions of 104 MBOE as a result of lower commodity prices; and
- positive revisions of 977 MBOE as a result of revised type curves.

All of our PUD drilling locations are scheduled to be drilled prior to the end of December 2025. This development schedule is based on a 136 well inventory waiting to be brought online, 148 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, we are 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, RSC reviewed and confirmed our drilling locations in estimating our PUD reserves in connection with the preparation of our reserve report as of December 31, 2020. 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,		
	2020	2019	2018
Production Data:			
Eagle Ford Shale:			
Oil (Bbls)	826,122	876,140	1,154,827
Natural gas (Bbls)	425,005	358,804	467,107
Natural gas liquids (Bbls)	224,985	276,656	259,924
Combined volumes (BOE)	1,476,112	1,511,600	1,881,858
Average daily combined volume (BOE/d)	4,033	4,141	5,156
Total:			
Oil (Bbls)	835,545	879,288	1,237,813
Natural gas (Bbls)	588,025	598,019	686,279
Natural gas liquids (Bbls)	247,536	296,813	293,086
Combined volumes (BOE)	1,671,106	1,774,120	2,217,178
Average daily combined volume (BOE/d)	4,566	4,861	6,074
% Oil	50%	50%	56%
Average sales prices:			
Oil (Bbls)	$ 35.84	$ 59.85	$ 67.14
Natural gas (Mcf)	$ 2.01	$ 2.62	$ 3.10
Natural gas liquids (Bbls)	$ 12.28	$ 15.45	$ 25.62
Combined per (BOE)	$ 23.98	$ 37.54	$ 46.63
Average Costs ($/BOE):			
Production and ad valorem taxes	$ 1.68	$ 2.40	$ 2.32
Gathering and transportation expense	$ 1.19	$ 1.35	$ 1.07
General and administrative	$ 7.18	$ 6.71	$ 4.30
Interest expense, net	$ 1.31	$ 1.40	$ 1.06
Depletion	$ 8.44	$ 7.18	$ 7.65

Producing Wells

As of December 31, 2020, we owned Royalties in 2,486 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	1,611	21
Natural Gas	875	11
Total	2,486	32

Acreage

The following tables set forth information as of December 31, 2020 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	83,480	110,562	194,042
Marcellus Shale and Point Pleasant	31,920	48,080	80,000
Total	115,400	158,642	274,042

Basin	Net Developed Acreage (1)	Net Undeveloped Acreage (2)	Total Net Acreage
Eagle Ford Shale	1,024	1,646	2,670
Marcellus Shale and Point Pleasant	478	1,052	1,530
Total	1,502	2,698	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, 2020.

(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, 2020, our operators associated with Royalties had 160 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,		
	2020	2019	2018
Development:			
Productive	139	194	235
Dry	-	-	-

Competition

The oil and natural gas industry is intensely competitive, and some of the companies we compete with 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 oil and natural gas are exempt from regulation as hazardous wastes under RCRA, these wastes typically constitute "solid wastes" that are subject to less stringent non-hazardous waste requirements. However, it is possible that RCRA could be amended or the EPA or state environmental agencies could adopt policies to require oil and natural gas exploration, development, and production wastes to become subject to more stringent waste handling requirements. Any changes in the laws and regulations could have a material adverse effect on our operators' capital expenditures and operating expenses, which in turn could affect production from our properties and adversely affect our business and prospects.

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, also known as the "Clean Water Act" ("CWA"), 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 CWA 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. In June 2015, the EPA and the U.S. Army Corps of Engineers (the "Corps") published a final rule attempting to clarify the federal jurisdictional reach over waters of the United States ("WOTUS"). Following the change in U.S. Presidential Administrations, there have been several attempts to modify or eliminate this rule. Most recently, on January 23, 2020, the EPA and Corps replaced the WOTUS rule adopted in 2015 with the narrower Navigable Waters Protection Rule, and litigation is expected. Therefore, the scope of jurisdiction under the CWA is uncertain at this time, and any increase in scope could result in increased costs or delays with respect to obtaining permits for certain activities for our operators. In addition, 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. 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.

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 into surface waters.

In addition, the SDWA grants the EPA broad authority to take action to protect public health when an underground source of drinking water is threatened with pollution that presents an imminent and substantial endangerment to humans, which could result in orders prohibiting or limiting the operations of oil and natural gas production facilities. The EPA has asserted regulatory authority pursuant to the SDWA's Underground Injection Control ("UIC") program over hydraulic fracturing activities involving the use of diesel fuel in fracturing fluids and issued guidance covering such activities. The SDWA also regulates saltwater disposal wells under the UIC Program. Recent concerns related to the operation of saltwater disposal wells and induced seismicity have led some states to impose limits on the total volume of produced water such wells can dispose of order disposal wells to cease operations, or limited the construction of new wells. These seismic events have also resulted in environmental groups and local residents filing lawsuits against operators in areas where the events occur seeking damages and injunctions limiting or prohibiting saltwater disposal well construction activities and operations. A lack of saltwater disposal wells in production areas could result in increased disposal costs for our operators if they are forced to transport produced water by truck, pipeline, or other method over long distances, or force them to curtail operations.

Noncompliance with the Clean Water Act, SDWA, or the OPA may result in substantial administrative, civil, and criminal penalties, as well as injunctive obligations, all of which could affect production from our properties and adversely affect our business and prospects.

Air Emissions

The federal Clean Air Act ("CAA") 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 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

The threat of climate change continues to attract considerable attention in the United States and in foreign countries, numerous proposals have been made and could continue to be made at the international, national, regional, and state levels of government to monitor and limit existing emissions of greenhouse gases ("GHGs") as well as to restrict or eliminate such future emissions. As a result, our operations as well as the operations of our operators are subject to a series of regulatory, political, litigation, and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, the current administration has highlighted addressing climate change as a priority and has issued several executive orders addressing climate change, including one that calls for substantial action on climate change, such as the increased use of zero-emission vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risks across government agencies and economic sectors. Moreover, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources and require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States. The regulation of methane from oil and gas facilities has been subject to uncertainty in recent years. The current administration has also issued an executive order calling for the suspension, revision, or rescission, of a September 2020 rule rescinding certain methane standards and removing transmission and storage segments from the source category for certain regulations, and the reinstatement or issuance of methane emissions standards for new, modified, and existing oil and gas facilities.

Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, the United Nations-sponsored "Paris Agreement," requires member states to submit non-binding, individually determined reduction goals every five years after 2020. Although the United States had withdrawn from the Paris Agreement, the current administration recently recommitted the United States to the agreement by executive order. However, the impacts of this executive order and the terms of any legislation or regulation to implement the United States' commitment remain unclear at this time.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate-change-related pledges made by some candidates now in political office. These have included promises to limit emissions and curtail certain production of oil and natural gas. Other actions that could be pursued by the current administration may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as more restrictive GHG emission limitations for oil and gas facilities. Litigation risks are also increasing as a number of cities and other local governments have sought to bring suit against the largest oil and natural gas companies in state or federal court, alleging among other things, that such companies created public nuisances by producing fuels that contributed to climate change or alleging that the companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose such impacts to their investors or customers.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies may elect in the future to shift some or all of their investments into non-energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, financial institutions may be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. The Federal Reserve recently joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector.

Limitation of investments in and financing for fossil fuel energy companies could result in the restriction, delay, or cancellation of drilling programs or development or production activities.

The adoption and implementation of new or more stringent international, federal, or state legislation, regulations, or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate the GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for oil and natural gas, which could reduce the profitability of our interests. Additionally, political, litigation, and financial risks may result in our oil and natural gas operators restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or impairing their ability to continue to operate in an economic manner, which also could reduce the profitability of our interests. One or more of these developments could have a material adverse effect on our business, financial condition, or results of operation.

Regulation of Hydraulic Fracturing

Our operators engage in hydraulic fracturing, a common practice that is used to stimulate production of hydrocarbons 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 process is typically regulated by state oil and natural gas commissions, but recently the EPA and other federal agencies have asserted jurisdiction over certain aspects of hydraulic fracturing. For example, the EPA issued effluent limitation guidelines in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants.

In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances. The EPA has not proposed to take any action in response to the report's findings.

Several states where we own interests in oil and gas producing properties, have adopted regulations that could restrict or prohibit hydraulic fracturing in certain circumstances or require the disclosure of the composition of hydraulic-fracturing fluids. For example, Texas has imposed certain limits on the permitting or operation of disposal wells in areas with increased instances of induced seismic events. These existing or any new legal requirements establishing seismic permitting requirements or similar restrictions on the construction or operation of disposal wells for the injection of produced water likely will result in added costs to comply and affect our operators' rate of production, which in turn could have a material adverse effect on our results of operations and financial position. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general or hydraulic fracturing in particular.

We cannot predict what additional state or local requirements may be imposed in the future on oil and gas operations in the states in which we own interests. In the event state, local, or municipal legal restrictions are adopted in areas where our operators conduct operations, our operators may incur substantial costs to comply with these requirements, which may be significant in nature, experience delays, or curtailment in the pursuit of exploration, development, or production activities and perhaps even be precluded from the drilling of wells.

There has been increasing public controversy regarding hydraulic fracturing with regard to increased risks of induced seismicity, 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 are adopted that significantly restrict hydraulic fracturing, those laws could make it more difficult or costly for our operators to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing is further regulated at the federal or state level, fracturing activities on our properties 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. Legislative changes could cause operators to incur substantial compliance costs. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

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 that 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.

Human Capital

Overview and Structure. We consider our workforce to be our most important asset, and we have sought to structure our hiring practices, compensation and benefits programs, and employee practices to attract and retain high-quality personnel and to provide a comfortable and collegial work environment. We continue to invest in our employees by providing training opportunities, promoting diversity and inclusion, and maintaining focus on corporate ethics. We are managed and operated the executive officers of our Company and our Board of Directors oversees the management of the Company.

Headcount. We rely principally on full-time employees but use independent contractors as needed to assist with special projects. As of December 31, 2020, the Company had 12 full-time employees and one contractor. None of Falcon's employees are represented by labor unions or covered by any collective bargaining agreements.

Recruiting. As a small, tight-knit community, our employees have broad responsibilities, and we encourage continuing development in their careers. When new opportunities arise within our organization, we may look within our organization for talent to fill those needs, ask for referrals from our team (who understand the diverse skill sets, high energy and forward-thinking attitude that contributes to delivering exceptional results), or work with recruiters who specialize in the areas of our vacancies.

Compensation. As part of our efforts to hire and retain highly qualified employees, we have structured compensation and benefits programs that, we believe, are extremely competitive and reward outstanding performance. In addition to the incentive programs in place for our named executive officers, which are described in detail in our proxy statement, we have structured an incentive bonus program for non-officer employees that is dependent on an employee's individual performance and our performance as a company. Our employees also receive restricted-share and performance-unit awards to encourage retention and align compensation with our company performance.

Healthcare and Other Benefits. We provide a robust suite of benefits to our employees covering all aspects of life, including 401(k) matching, medical-insurance options, and programs to encourage and support the whole person, including physical, mental and emotional, financial, social, career, and community service initiatives.

Facilities

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. Our Houston, TX office is shared with Hepco Capital Management, LLC ("Hepco"), which Company executive Jeffrey Brotman is also a director and officer of. The related cost of our shared office is proportionately shared between the Company and Hepco. 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. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at www.sec.gov.

ITEM 1A. RISK FACTORS (As restated)

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 or decreases in U.S. domestic production;
- the ability of members of the OPEC to agree to and maintain oil price and production controls;
- risk related to our hedging activities;
- 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 COVID-19 pandemic and the significant decline in commodity prices in 2020 has adversely affected our business, and the ultimate effect on our financial condition, results of operations, and cash dividends to shareholders will depend on future developments, which are highly uncertain and cannot be predicted.

The COVID-19 pandemic has adversely affected the global economy, disrupted global supply chains, and created significant volatility in the financial markets. In addition, the pandemic has resulted in travel restrictions, business closures and the institution of quarantining and other restrictions on movement in many communities. As a result, there has been a significant reduction in demand for and prices of oil, natural gas, and NGLs. In the first quarter of 2020 and into the second quarter of 2020, oil prices fell sharply and dramatically, due in part to significantly decreased demand as a result of the COVID-19 pandemic and the announcement by Saudi Arabia of a significant increase in its maximum oil production capacity as well as the announcement by Russia that previously agreed upon oil production cuts between members of OPEC+ would expire on April 1, 2020, and the ensuing expiration thereof. Agreed-upon production cuts by OPEC+ along with declining U.S. production have helped to correct the supply and demand imbalance; however, these reductions are not expected to be enough in the near-term to offset the significant inventory build caused by demand destruction from the COVID-19 pandemic in the first half of 2020. Prices for oil were over $60 per barrel at the beginning of 2020 before declining significantly through March and further declining into April. While oil prices modestly recovered, a reversal of recent improvements or a prolonged period at current prices may materially and adversely affect our financial condition, results of operations, and cash dividends to shareholders.

In a prolonged period of low commodity prices, we may be required to impair certain oil and gas producing properties and the borrowing base under our Credit Facility could be reduced. Effective November 1, 2020, in connection with our fall redetermination, the borrowing base was reduced to $70 million.

The impact of the COVID-19 pandemic has negatively affected the oil and natural gas business environment, primarily by causing a reduction in commercial activity and travel worldwide thereby lowering energy demand. This, in turn, has resulted in significantly lower market prices for oil, natural gas, and natural gas liquids. While we use derivative instruments to partially mitigate the impact of commodity price volatility, our revenues and operating results depend significantly upon the prevailing prices for oil and natural gas. The current price environment has caused many of our operators to reduce their drilling and completion activity on our acreage and caused some of our operators to temporarily shut-in production from existing wells, both of which negatively impact our production volumes. While we believe most of the shut-in production has been brought back on-line, drilling and completion activity remains depressed relative to pre-pandemic levels.

The extent to which the COVID-19 pandemic adversely affects our business, results of operations, and financial condition will depend on future developments, which are highly uncertain and cannot be predicted, including the scope and duration of the pandemic and actions taken by governmental authorities and other third parties in response to the pandemic.

Our hedging activities could result in financial losses and reduce earnings.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently have entered, and may in the future enter, into derivative contracts for a portion of our future oil and natural gas production, including fixed price swaps, collars, and basis swaps. We have not designated and do not plan to designate any of our derivative contracts as hedges for accounting purposes and, as a result, record all derivative contracts on our balance sheet at fair value with changes in fair value recognized in current period earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative contracts. Derivative contracts also expose us to the risk of financial loss in some circumstances, including when:

- production is less than expected;
- the counterparty to the derivative contract defaults on its contract obligation;
- the actual differential between the underlying price in the derivative contract, or
- actual prices received are materially different from those expected.

In addition, these types of derivative contracts can limit the benefit we would receive from increases in the prices for oil and natural gas.

We depend on three 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, 2020, we received approximately 42%, 20%, and 16% of our revenue from ConocoPhillips Company ("ConocoPhillips"), EOG Resources, Inc. ("EOG"), and Devon Energy Corporation ("Devon"), 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, 2020, 61.3% 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 effectively integrate 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, 2020, 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, 2020 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, 2020, 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.

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.

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.

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.

We have identified a material weakness in our internal control over financial reporting, which has exposed us to a number of additional risks and uncertainties.

We are required to maintain internal control over financial reporting adequate to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements in accordance with generally accepted accounting principles in the United States. In connection with the restatement of our audited consolidated financial statements as of December 31, 2020 and 2019 and for the years ended December 31, 2020, 2019 and 2018, we determined that we had a material weakness as of December 31, 2020, namely that our controls over the review of certain material non-routine transactions or events were not effective. Due to this material weakness, we have concluded that as of December 31, 2020, our internal control over financial reporting was not effective. This Amendment No. 1 to Annual Report on Form 10-K/A contains restated consolidated financial statements for the periods referenced above to correct for errors caused by this weakness. We do not expect that our internal control over financial reporting will prevent all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. Over time, controls may become inadequate because changes in conditions or deterioration in the degree of compliance with policies or procedures may occur. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. As a result, we cannot assure that significant deficiencies or material weaknesses in our internal control over financial reporting will not be identified in the future. A material weakness means a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of the registrant's annual or interim financial statements will not be prevented or detected on a timely basis.

Our warrants are accounted for as liabilities and the changes in value of our warrants could have a material effect on our financial results.

On April 12, 2021, the SEC issued the Staff Statement. Specifically, the Staff Statement focused on certain settlement terms and provisions related to certain tender offers following a business combination, which terms are similar to those contained in the warrant agreement governing the Warrants. As a result of the Staff Statement, we reevaluated the accounting treatment of the Company's Public and Private Placement Warrants and determined to classify the Warrants as derivative liabilities measured at fair value, with changes in fair value each period reported in earnings.

Due to certain settlement provisions contained within the Warrants, the Warrants are classified as derivative liabilities on our consolidated balance sheets as of December 31, 2020 and 2019. Accounting Standards Codification 815-40, Derivatives and Hedging – Contracts in Entity's Own Equity ("ASC 815"), provides for the remeasurement of the fair value of such derivatives at each balance sheet date, with a resulting non-cash gain or loss related to the change in the fair value being recognized in earnings in the statement of operations. As a result of the recurring fair value measurement, our consolidated financial statements and results of operations may fluctuate quarterly, based on factors that are outside of our control. Due to the recurring fair value measurement, we expect that we will recognize non-cash gains or losses on the Warrants each reporting period and that the amount of such non-cash gains or losses could be material.

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 payout ratio at any time and there is no guarantee that we will pay dividends in the future.

Although we have historically paid 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 Company's Second Amended & Restated Charter (the "Second A&R 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 payout ratio 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.

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 46% 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.

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 Industry

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 would expire on April 1, 2020. These actions led to an immediate and steep decrease in oil prices. In early April 2020, in response to significantly depressed global oil prices, 23 countries, led by Saudi Arabia and Russia, committed to withhold collectively 9.7 million barrels a day of oil from global markets. 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.

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.

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.

Our operations are subject to a series of risks related to climate change.

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. In the United States to date, no comprehensive climate change legislation has been implemented at the federal level. However, President Biden has announced that climate change will be a focus of his administration. On January 27, he issued an executive order calling for substantial action on climate change, including, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risks across agencies and economic sectors. Additionally, federal regulators, state and local governments, and private parties have taken (or announced that they plan to take) actions related to climate change that have or may have a significant impact on our operations. For example, in response to findings that emissions of carbon dioxide, methane and other GHGs endanger public health and the environment, the EPA has adopted regulations under existing provisions of the Clean Air Act that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources that are already potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that will be established by the states or, in some cases, by the EPA for those emissions. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from certain sources in the United States on an annual basis, including certain of our operations; moreover, President Biden signed an executive order on January 20, 2021 that, among other things, calls for the establishment of new or more stringent emissions standards for methane and volatile organic compounds from new, modified, and existing oil and gas facilities, including the transmission and storage segments.

Internationally, the United Nations-sponsored “Paris Agreement” requires member states to individually determine and submit non-binding emissions reduction targets every five years after 2020. Although the United States had withdrawn from the Paris Agreement in November 2020, President Biden has signed executive orders to re-enter the Paris Agreement and calling on the federal government to develop the United States' emissions reduction target. The impacts of President Biden's executive orders and the terms of any laws or regulations promulgated to implement the United States’ commitment under the Paris Agreement, are uncertain at this time. Increasingly, fossil fuel companies are also exposed to litigation risks from climate change.

Additionally, in response to concerns related to climate change, companies in the fossil fuel sector may be exposed to increasing financial risks. Financial institutions, including investment advisors and certain sovereign wealth, pension, and endowment funds, may elect in the future to shift some or all of their investment into non-fossil fuel related sectors. Institutional lenders who provide financing to fossil-fuel energy companies have also become more attentive to sustainable lending practices, and some of them may elect in future not to provide funding for fossil fuel energy companies. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Recently, President Biden signed an executive order calling for the development of a "climate finance plan," and, separately, the Federal Reserve announced that it has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. A material reduction in the capital available to the fossil fuel industry could make it more difficult to secure funding for exploration, development, production, transportation, and processing activities, which could in turn reduce demand for our services adversely impact our financial performance.

Risks Relating to Regulation

We may incur significant costs in the future associated with proposed climate change regulation and legislation.

The United States Congress and some states where we have operations may consider legislation or regulations related to greenhouse gas emissions, including methane emissions, which may compel reductions of such emissions. In addition, there have been international conventions and efforts to establish standards for the reduction of greenhouse gases globally, including the Paris accords in December 2015. The conditions for entry into force of the Paris accords were met on October 5, 2016 and the Agreement went into force 30 days later on November 4, 2016. While the Trump administration had begun the process of withdrawing from the Paris Agreement, in January 2021, President Biden signed an Executive Order directing that the United States rejoin the Paris Agreement. Legislative proposals have included or could include limitations, or caps, on the amount of greenhouse gas that can be emitted, as well as a system of emissions allowances. For example, legislation passed by the U.S. House of Representatives in 2010, which was not taken up by the Senate, would have placed the entire burden of obtaining allowances for the carbon content of NGLs on the owners of NGLs at the point of fractionation. In June 2013, President Obama announced a climate action plan that targeted methane emissions from the oil and gas industry as part of a comprehensive interagency methane reduction strategy, and in June 2016, the EPA expanded the NSPS regulations for new or modified sources of VOCs to include methane emissions, which, among other things, imposes leak detection and repair requirements for VOCs and methane on producer well site equipment and on midstream equipment such as compressor and booster stations, imposes additional emission reduction requirements on specific pieces of oil and gas equipment, and is a regulatory pre-condition to the EPA acting to regulate existing oil and gas methane sources in the future under Section 111(d) of the Clean Air Act. The Trump administration targeted many of these actions. For example, on September 14 and 15, 2020, EPA finalized amendments to the 2012 and 2016 regulations that, among other things, removed the transmission and storage segment of the oil and gas industry from regulation and rescinded emissions standards for that sector and rescinded methane standards. However, the Biden administration has identified these amendments for review. Relatedly, the D.C. Circuit Court challenge to the October 2015 EPA regulation reducing the ambient ozone standard from 75 parts per billion to 70 parts per billion under the Clean Air Act was put in abeyance temporarily while the EPA reviewed the regulation. The EPA later indicated it will not revise the rule, and challenges from industry and environmental groups moved forward. In August 2019, the D.C. Court of Appeals upheld the health-based ozone standards but remanded to the EPA the secondary, public welfare standards designed to protect environmental values. The 2015 Ozone standard is being implemented pursuant to the December 2018 final implementation rule. Separately, in 2011 the EPA issued permitting rules for sources of greenhouse gases; however, in June 2014, the U.S. Supreme Court reversed a D.C. Circuit Court of Appeals decision that had upheld these rules and struck down the EPA's greenhouse gas permitting rules to the extent they impose a requirement to obtain a permit based solely on emissions of greenhouse gases. Under the Court ruling and the EPA's subsequent proposed rules, major sources of other air pollutants, such as VOCs or nitrogen oxides, could still be required to implement process or technology controls and obtain permits regarding emissions of greenhouse gases. These proposed rules have not been finalized. The EPA has issued rules requiring reporting of greenhouse gases, on an annual basis, for certain onshore natural gas and oil production facilities, and in October 2015, the EPA amended and expanded those greenhouse gas reporting requirements to all segments of the oil and gas industry effective January 1, 2016. Similarly, some states can initiate and promulgate regulations affecting oil and gas operations and associated greenhouse gas emissions as a matter of their own statutory authority and programs. For example, in 2019, the Colorado legislature passed House Bill 19-1261, the "Climate Action Plan to Reduce Pollution" that sets greenhouse gas emission reduction targets for the state. Subsequently, the governor issued the Colorado Greenhouse Gas Pollution Roadmap, which identifies pathways to meet the reduction targets. The Roadmap identifies the oil and gas sector as one of the larger contributors to greenhouse gas emissions in the state and asserts that deep reductions in methane emissions from the oil and gas industry will be required to meet the targets. Judicial challenges to new regulatory measures are likely and we cannot predict the outcome of such challenges. New regulatory suspensions, revisions, or rescissions, as well as new regulations and conflicting state and federal regulatory mandates may inhibit our ability to accurately forecast the costs associated with future regulatory compliance. To the extent legislation is enacted or additional regulations are promulgated that regulate greenhouse gas emissions, it could significantly increase our costs to (i) acquire allowances; (ii) permit new large facilities; (iii) operate and maintain our facilities; (iv) install new emission controls or institute emission reduction measures; and (v) manage a greenhouse gas emissions program. If such legislation becomes law or additional rules are promulgated in the United States or any states in which we have operations and we are unable to pass these costs through as part of our services, it could have an adverse effect on our business and cash available for distributions.

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. For example, the Biden Administration has issued orders temporarily suspending the issuance of new authorizations and suspending the issuance of new leases pending completion of a review of current practices, for oil and gas development on federal lands and waters (but not tribal lands that the federal government merely holds in trust). Any of these environmental initiatives and regulations, could have a material adverse effect on our financial condition and results of operations.

Risks Related to our Capital Structure

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 46% 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 nine of the directors on our Board of Directors so long as Blackstone, together with its affiliates, holds at least 41% 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 ours 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 ours 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 Warrant 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 46% 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.

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.

General Risk Factors

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 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 that is neither an emerging growth company nor an emerging growth company that 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.

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 11 registered stockholders of record of our Class A Common Stock and nine registered holders of our warrants as of March 4, 2021. This number does not include owners, stockholders or warrant holders 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 4, 2021, we had seven holders of record of our Class C Common Stock.

Cash Dividends

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 the 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

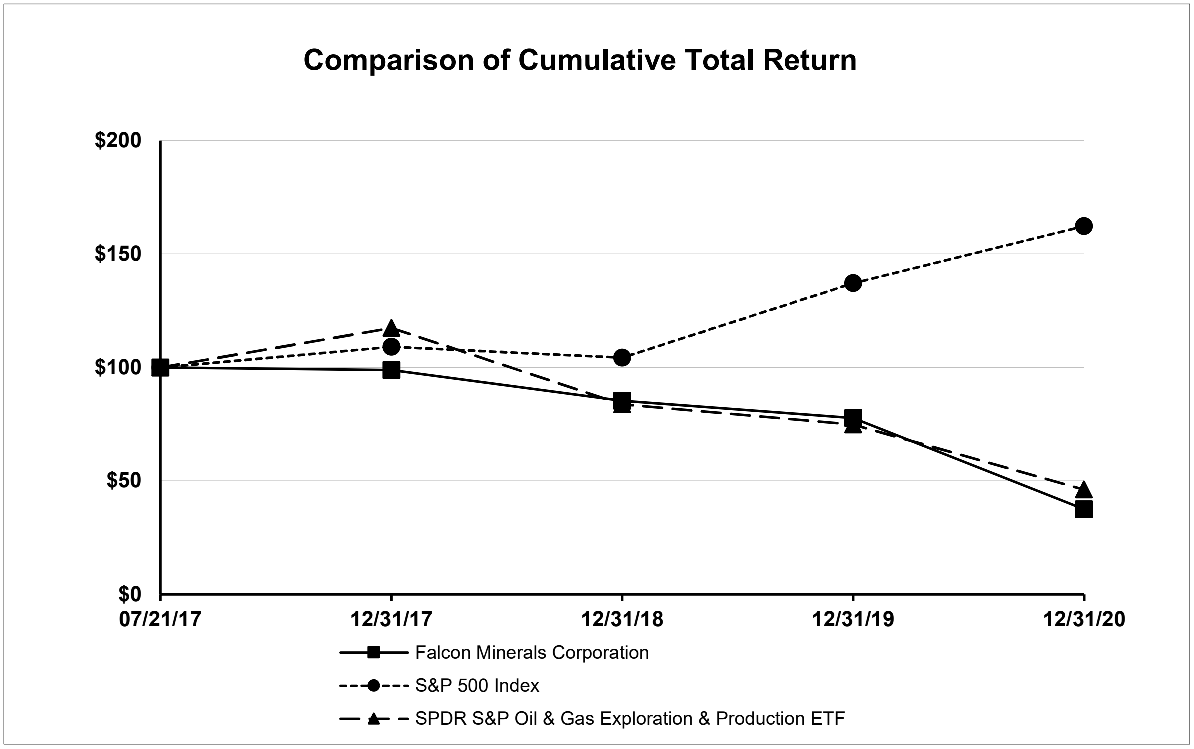
The following table sets forth information as of December 31, 2020 with respect to equity compensation plans under which shares of our common stock are authorized for issuance:

	(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)	2,853,323	-	5,289,030
Equity compensation plans not approved by stockholders:	-	-	-
Total	2,853,323	-	5,289,030

(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, 2020 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 44 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 (As restated)

Restatement of Previously Issued Consolidated Financial Statements

We have restated our previously issued consolidated financial statements contained in the Original Form 10-K. Refer to the "Explanatory Note" preceding Item 1, Business, for background on the restatement, the periods impacted, control considerations, and other information. In addition, we have restated certain previously reported financial information as of December 31, 2020 and 2019 and for the fiscal years ended December 31, 2020, 2019 and 2018 in this Item 6, Selected Financial Data. See Note 3, Restatement of Previously Issued Consolidated Financial Statements, in Item 15, Exhibits and Financial Statements, for additional information related to the restatement, including descriptions of the misstatements and the impacts to our consolidated financial statements.

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, 2020, 2019, 2018, 2017 and 2016 are derived from our audited historical consolidated financial statements. Our financial statements have been prepared in accordance with GAAP.

In addition, the following financial information includes information regarding Royal Resources L.P. as Falcon's predecessor entity, which includes certain interests in subsidiary companies that 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 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,				
	2020 (As restated)	2019 (As restated)	2018 (As restated)	2017	2016
Revenues:					
Oil and gas sales	$ 40,081	$ 68,463	$ 98,655	$ 95,972	$ 70,964
Gain (loss) on commodity derivative instruments	(1,200)	-	(1,456)	1,791	(843)
Total revenue	38,881	68,463	97,199	97,763	70,121
Operating expenses:					
Production and ad valorem taxes	2,807	4,262	5,143	5,242	4,531
Marketing and transportation	1,993	2,396	2,368	6,505	6,605
Amortization of royalty interests in oil and natural gas properties	14,103	12,737	16,962	33,837	35,840
General, administrative, and other	11,997	11,912	9,544	8,213	6,114
Total operating expenses	30,900	31,307	34,017	53,797	53,090
Operating income	7,981	37,156	63,182	43,966	17,031
Other income (expense):					
Gain on the sale of assets	-	-	41,382	31,441	-
Change in fair value of warrant liability	5,128	6,069	27,800	-	-
Other income	125	165	46	34	823
Interest expense	(2,197)	(2,489)	(2,350)	(2,746)	(3,096)
Total other income (expense)	3,056	3,745	66,878	28,729	(2,273)
Income before income taxes	11,037	40,901	130,060	72,695	14,758
Provision for income taxes	589	3,918	3,292	-	-
Income from continuing operations	10,448	36,983	126,768	72,695	14,758
Income from discontinued operations	-	-	2,139	2,978	22
Net income	10,448	36,983	128,907	75,673	14,780
Net income attributable to non-controlling interests	(2,748)	(16,564)	(10,982)	(155)	(69)
Net income attributable to common shareholders/unitholders	$ 7,700	$ 20,419	$ 117,925	$ 75,518	$ 14,711

	Year Ended December 31,				
	2020 (As restated)	2019 (As restated)	2018 (As restated)	2017	2016
Earnings per share:					
Common shares - basic	$ 0.17	$ 0.44	$ 0.81	N/A	N/A
Common shares - diluted	$ 0.11	$ 0.39	$ 0.53	N/A	N/A
Cash Dividends Declared Per Share:	$ 0.195	$ 0.595	$ 0.30	N/A	N/A
Statement of Cash Flow Data:					
Net cash flows provided by (used in):					
Operating activities	$ 27,434	$ 55,229	$ 77,886	$ 80,791	$ 51,279
Investing activities	(2,431)	(23,353)	122,312	83,048	(5,260)
Financing activities	(24,822)	(36,650)	(203,378)	(161,390)	(76,225)
Other Financial Data:					
Adjusted EBITDA (1)	$ 26,737	$ 52,682	$ 80,190	$ 77,837	$ 53,625
Balance Sheet Data (at period end):					
Cash and cash equivalents	$ 2,724	$ 2,543	$ 7,317	$ 8,345	$ 5,536
Total assets	275,629	290,205	291,235	352,718	435,897
Long-term debt (including current portion)	39,800	42,500	21,000	57,000	57,683
Total liabilities	47,228	53,810	36,221	63,561	62,023
Shareholder's equity / Partners' capital	228,401	236,395	255,014	289,157	373,874
Production Data					
Oil (Bbls)	835,545	879,288	1,237,813	1,582,322	1,474,218
Natural gas (BOE)	588,025	598,019	686,279	760,982	690,613
Natural gas liquids (Bbls)	247,536	296,813	293,086	542,706	511,337
Combined volumes (BOE)	1,671,106	1,774,120	2,217,178	2,886,010	2,676,168
Average daily combined volume (BOE/d)	4,566	4,861	6,074	7,907	7,332
% Oil	50%	50%	56%	55%	55%
Average sales prices:					
Oil (Bbls)	$ 35.84	$ 59.85	$ 67.14	$ 50.54	$ 39.96
Natural gas (Mcf)	$ 2.01	$ 2.62	$ 3.10	$ 2.81	$ 2.19
Natural gas liquids (Bbls)	$ 12.28	$ 15.45	$ 25.62	$ 20.63	$ 12.04
Combined per (BOE)	$ 23.98	$ 37.54	$ 46.63	$ 35.67	$ 27.69
Average Costs ($/BOE):					
Production and ad valorem taxes	$ 1.68	$ 2.40	$ 2.32	$ 1.82	$ 1.69
Gathering and transportation expense	$ 1.19	$ 1.35	$ 1.07	$ 2.25	$ 2.47
General and administrative	$ 7.18	$ 6.71	$ 4.30	$ 2.85	$ 2.28
Interest expense, net	$ 1.31	$ 1.40	$ 1.06	$ 0.95	$ 1.16
Depletion	$ 8.44	$ 7.18	$ 7.65	$ 11.72	$ 13.39

(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.

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."

Restatement of Previously Issued Consolidated Financial Statements

We have restated our previously issued consolidated financial statements contained in the Original Form 10-K. Refer to the "Explanatory Note" preceding Item 1, Business, for background on the restatement, the periods impacted, control considerations, and other information. In addition, we have restated certain previously reported financial information as of December 31, 2020 and 2019 and for the fiscal years ended December 31, 2020, 2019 and 2018 in this Item 7, Management's Discussion and Analysis of Financial Condition, including but not limited to information within the Result of Operations and Liquidity and Capital Resources sections. See Note 3, Restatement of Previously Issued Consolidated Financial Statements, in Item 15, Exhibits and Financial Statements, for additional information related to the restatement, including descriptions of the misstatements and the impacts to our consolidated financial 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

COVID-19 Pandemic. The COVID-19 pandemic and related economic repercussions have resulted in a significant reduction in demand for and prices of oil, natural gas and NGLs. In the first quarter of 2020 and into the second quarter of 2020, oil prices fell sharply, due in part to significantly decreased demand as a result of the COVID-19 pandemic and the announcement by Saudi Arabia of a significant increase in its maximum oil production capacity as well as the announcement by Russia that previously agreed upon oil production cuts between members of the Organization of the Petroleum Exporting Countries and its broader partners ("OPEC+") would expire on April 1, 2020, and the ensuing expiration thereof. Agreed-upon production cuts by OPEC+ along with declining U.S. production have helped to correct the supply and demand imbalance; however, these reductions are not expected to be enough in the near-term to offset the significant inventory build caused by demand destruction from the COVID-19 pandemic. These market conditions have resulted in a decline in drilling activity as operators revise their capital budgets downward and adjust their operations in response to lower commodity prices. While oil prices have remained depressed, both natural gas spot prices and contract future prices for the full year 2021 have improved significantly from levels seen in the second quarter of 2020. Given the dynamic nature of these events, we cannot reasonably estimate the period of time that the COVID-19 pandemic and related market conditions will persist.

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 were 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, 2020, our Royalties represented the right to receive an average of 1.27% 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, NGLs and natural gas prices have historically been volatile therefore, from time to time, we have entered into derivative instruments to partially mitigate the impact of commodity price volatility on our cash generated from operations. Such instruments may include variable-to-fixed-price swaps, fixed price contracts, costless collars, and other contractual agreements. The impact of these derivative instruments could affect the amount of revenue we ultimately realize. We intend to continuously monitor the production from our assets and the commodity price environment, and will, from time to time, add additional hedges in the future. We do not enter into derivative instruments for speculative purposes. Our open commodity derivative contracts as of December 31, 2020 are detailed in "Note 5—Commodity Derivative Financial Instruments" to our audited consolidated financial statements included elsewhere in this Annual Report.

During the year ended December 31, 2020, the West Texas Intermediate average monthly posted prices ranged from $16.70 to $57.86 per Bbl for crude oil and the Henry Hub settlement price of natural gas ranged from $1.50 to $3.00 per MMBtu for natural gas. During the year ended December 31, 2019, West Texas Intermediate monthly average posted prices 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. During the year ended December 31, 2018, West Texas Intermediate monthly average posted prices ranged from $49.98 to $70.76 per Bbl for crude oil and the Henry Hub settlement price of natural gas ranged from $2.64 to $4.72 per MMBtu

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

	Year Ended December 31,		
	2020	**2019**	**2018**
Royalty Income:			
Oil sales	75%	77%	81%
Natural gas sales	18%	14%	12%
Natural gas liquids sales	7%	7%	7%
Lease bonus	0%	2%	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, 2020, 2019 and 2018:

	Year Ended December 31,		
	2020	**2019**	**2018**
Oil (Bbls)	$ 35.84	$ 59.85	$ 67.14
Natural gas (Mcf)	$ 2.01	$ 2.62	$ 3.10
Natural gas liquids (Bbls)	$ 12.28	$ 15.45	$ 25.62

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.

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 based on proved and risk adjusted unproved oil and gas reserves and forecasted commodity pricing, 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.

Overview of Our Results of Operations

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

	As restated		
	Year Ended December 31,		
	2020	2019	2018
Revenues:			
Oil and gas sales	$ 40,081	$ 68,463	$ 98,655
Gain (loss) on commodity derivative instruments	(1,200)	-	(1,456)
Total revenue	38,881	68,463	97,199
Operating expenses:			
Production and ad valorem taxes	2,807	4,262	5,143
Marketing and transportation	1,993	2,396	2,368
Amortization of royalty interests in oil and natural gas properties	14,103	12,737	16,962
General, administrative, and other	11,997	11,912	9,544
Total operating expenses	30,900	31,307	34,017
Operating income	7,981	37,156	63,182
Other income (expense):			
Gain on the sale of assets	-	-	41,382
Change in fair value of warrant liability	5,128	6,069	27,800
Other income	125	165	46
Interest expense	(2,197)	(2,489)	(2,350)
Total other income (expense)	3,056	3,745	66,878
Income before income taxes	11,037	40,901	130,060
Provision for income taxes	589	3,918	3,292
Income from continuing operations	10,448	36,983	126,768
Income from discontinued operations	-	-	2,139
Net income	10,448	36,983	128,907
Net income attributable to non-controlling interests	(2,748)	(16,564)	(10,982)
Net income attributable to common shareholders/unitholders	$ 7,700	$ 20,419	$ 117,925
Other Financial Data:			
Adjusted EBITDA [(1)]	$ 26,737	$ 52,682	$ 80,190

(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,		
	2020	2019	2018
Production Data:			
Oil (Bbls)	835,545	879,288	1,237,813
Natural gas (BOE)	588,025	598,019	686,279
Natural gas liquids (Bbls)	247,536	296,813	293,086
Combined volumes (BOE)	1,671,106	1,774,120	2,217,178
Average daily combined volume (BOE/d)	4,566	4,861	6,074
% Oil	50%	50%	56%
Average sales prices:			
Oil (Bbls)	$ 35.84	$ 59.85	$ 67.14
Natural gas (Mcf)	$ 2.01	$ 2.62	$ 3.10
Natural gas liquids (Bbls)	$ 12.28	$ 15.45	$ 25.62
Combined per (BOE)	$ 23.98	$ 37.54	$ 46.63
Average Costs ($/BOE):			
Production and ad valorem taxes	$ 1.68	$ 2.40	$ 2.32
Marketing and transportation expense	$ 1.19	$ 1.35	$ 1.07
General and administrative	$ 7.18	$ 6.71	$ 4.30
Interest expense, net	$ 1.31	$ 1.40	$ 1.06
Depletion	$ 8.44	$ 7.18	$ 7.65

Comparison of Year Ended December 31, 2020 to Year Ended December 31, 2019

Oil and Gas Revenues

Oil and gas revenues decreased $29.6 million, or 43%, to $38.9 million for the year ended December 31, 2020, from $68.5 million for the year ended December 31, 2019. The decrease in oil and gas revenues was attributable to a decrease in oil and natural gas production in addition to a 40% decrease in realized oil and a 23% decrease in realized natural gas prices. We received an average price of $35.84 per Bbl of oil and $2.01 per Mcf of gas sold during the year ended December 31, 2020 compared to $59.85 per Bbl of oil and $2.62 per Mcf of gas sold during the year ended December 31, 2019. In addition, during 2020, we recognized a $1.2 million loss from our commodity derivative instruments. We did not enter into any commodity derivative instruments during 2019.

Production and Ad Valorem Taxes

Production and ad valorem taxes decreased $1.5 million, or 34%, to $2.8 million for the year ended December 31, 2020, from $4.3 million for the year ended December 31, 2019. The decrease in production and ad valorem taxes was attributable to the decrease in production. As a percentage of oil and gas revenues, production and ad valorem taxes were 7% for the year ended December 31, 2020 compared to 6% for the year ended December 31, 2019. This increase, as a percentage of revenue, was partially due to the approximately 40% and 23% decrease, respectively, in the average realized price of oil and natural gas as compared to 2019.

Marketing and Transportation Expense

Marketing and transportation expense decreased $0.4 million or 17%, to $2.0 million for the year ended December 31, 2020, from $2.4 million for the year ended December 31, 2019. As a percentage of revenues, marketing and transportation expense was 5% during the year ended December 31, 2020 as compared to 4% for the prior year. The increase in marketing and transportation expense as a percentage of revenues during 2020 was attributable to fixed transportation costs incurred under our leases that do not decrease along with the realized price on the sale of oil and natural gas.

Amortization of Royalty Interests in Oil and Natural Gas Properties Expense

Amortization of royalty interests in oil and natural gas properties expense increased $1.4 million, or 11%, to $14.1 million for the year ended December 31, 2020, from $12.7 million for the year ended December 31, 2019. The increase in amortization of royalty interests in oil and gas properties expense was primarily attributable to the impact of higher depletion rates which was partially offset by lower production. The higher depletion rates were primarily driven by decreases in estimated proved developed producing reserve quantities in the Eagle Ford as adjusted in our 2020 year-end reserve reports.

General, Administrative, and Other Expense

General, administrative, and other expense increased by $0.1 million, or 1%, to $12.0 million for the year ended December 31, 2020, from $11.9 million for the year ended December 31, 2019. The increase in general, administrative, and other expense was attributable to $0.8 million of expenses incurred as a part of the strategic review process which management had begun during the third quarter of 2020 and an increase of $0.9 million in stock-based compensation. These increases were partially offset by cost cutting measures implemented by management during the first quarter of 2020 due to the effects of the pandemic.

Change in Fair Value of Warrant Liability

The change in the fair value of warrant liability decreased by $0.9 million, or 16% to $5.1 million for the year ended December 31, 2020, from $6.1 million for the year ended December 31, 2019. The decrease in the fair value of the warrant liability is attributable to the decrease in the Company's stock price that was used in determining the fair value of the warrant liability.

Interest Expense

Interest expense decreased by $0.3 million, or 12%, to $2.2 million for the year ended December 31, 2020, from $2.5 million for the year ended December 31, 2019. The decrease in interest expense was attributable to lower average outstanding borrowings under our Credit Facility as well as lower average interest rates.

Income Taxes

Income tax expense decreased to $0.6 million for the year ended December 31, 2020, compared to $3.9 million for the year ended December 31, 2019. The decrease in income taxes was attributed to a decrease in taxable income during the year ended December 31, 2020 as compared to the same period during 2019 attributable to lower production and lower average realized prices during 2020.

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.

Change in Fair Value of Warrant Liability

The change in the fair value of warrant liability decreased by $21.7 million, or 78% to $6.1 million for the year ended December 31, 2019, from $27.8 million for the year ended December 31, 2018. The decrease in the fair value of the warrant liability is attributable to the decrease in the Company's stock price that was used in calculating the fair value of the warrant liability.

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.

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 before interest expense, net, depletion expense, provision for income taxes, depreciation, unrealized gains and losses on commodity derivative instruments, non-cash gains and losses on revaluation of warrant liability, and non-cash equity-based compensation. 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).

	As restated		
	Year Ended December 31,		
	2020	2019	2018
Net income	$ 10,448	$ 36,983	$ 128,907
Income attributable to discontinued operations	-	-	(2,139)
Interest expense, net	2,197	2,489	2,350
Depletion	14,103	12,737	16,962
Income taxes	589	3,918	3,292
Depreciation	104	75	-
Unrealized loss on commodity derivative instruments	944	-	-
Change in fair value of warrant liability	(5,128)	(6,069)	(27,800)
Gain on the sale of assets	-	-	(41,382)
Share-based compensation	3,480	2,549	-
Adjusted EBITDA	$ 26,737	$ 52,682	$ 80,190

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. 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 effects of the COVID-19 outbreak and the recent oil price decline could have significant adverse consequences for general economic, financial and business conditions, as well as for our business and financial position and the business and financial position of the operators of our mineral interests and may, among other things, impact our ability to generate cash flows from operations, access the capital markets on acceptable terms or at all, and affect our future need or ability to borrow under our Credit Facility. In addition to our potential sources of funding, the effects of such global events may impact our liquidity or need to alter our allocation or sources of capital, implement further cost reduction measures, and change our financial strategy. Although the COVID-19 outbreak and the recent oil price decline could have a broad range of effects on our sources and uses of liquidity, the ultimate effect thereon, if any, will depend on future developments, which cannot be predicted at this time.

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, 2020	$ 0.0750	$ 3,458	March 8, 2021	February 25, 2021
September 30, 2020	$ 0.0650	$ 2,997	December 8, 2020	November 24, 2020
June 30, 2020	$ 0.0300	$ 1,383	September 8, 2020	August 25, 2020
March 31, 2020	$ 0.0250	$ 1,150	June 8, 2020	May 25, 2020
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 $70.0 million, subject to scheduled semi-annual and other borrowing base redeterminations and expires on the fifth anniversary of the Closing Date. As of December 31, 2020, the Company had borrowings of $39.8 million under the Credit Facility at an interest rate of 2.65% and $30.2 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, 2020, 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.

On July 27, 2017, the U.K. Financial Conduct Authority announced that it intends to stop persuading or compelling banks to submit LIBOR rates after 2021. Our Credit Facility includes provisions to determine a replacement rate for LIBOR if necessary during its term, which require that we and our lenders agree upon a replacement rate based on the then-prevailing market convention for similar agreements. We currently do not expect the transition from LIBOR to have a material impact on us. However, if clear market standards and replacement methodologies have not developed as of the time LIBOR becomes unavailable, we may have difficulty reaching agreement on acceptable replacement rates under our Credit Facility. In the event that we do not reach agreement on an acceptable replacement rate for LIBOR, outstanding borrowings under the Credit Facility would revert to a floating rate equal to the alternative base rate (which, as of the time that LIBOR becomes unavailable, is equal to the greater of the agent bank's reference rate and the federal funds effective rate plus 0.50%) plus the applicable margin for the alternative base rate which ranges between 1.00% and 2.00%. If we are unable to negotiate replacement rates on favorable terms, it could have a material adverse effect on our financial condition, results of operations, and cash distributions to unitholders.

Cash Flows

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

A summary of the changes in cash flow data for the years ended December 31, 2020 and 2019 are set forth in the following table (in thousands, except percentages):

	Year Ended December 31,			
	2020	**2019**	**$ Change**	**% Change**
Net cash flows provided by (used in):				
Operating activities	$ 27,434	$ 55,229	$ (27,795)	-50%
Investing activities	(2,431)	(23,353)	20,922	-90%
Financing activities	(24,822)	(36,650)	11,828	-32%

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, 2020 as compared to the year ended December 31, 2019 was primarily related to a 5% decrease in oil production, a 2% decrease in natural gas production coupled with a 40% decrease in realized oil prices and a 23% decrease in realized natural gas prices period over period. In addition, the Company experienced a decrease 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, 2020 was $2.4 million and the majority was related to the acquisition of certain royalty interests in oil and natural gas properties. 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 Flow from Financing Activities. Cash used in financing activities for the year ended December 31, 2020 was $24.8 million, primarily related to dividends and distributions totaling $21.9 million and a net decrease in borrowings under our Credit Facility of $2.7 million. The repayment of borrowings under our Credit Facility was paid from cash flow generated by our operations during the period. 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.

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.

Contractual Obligations

We have contractual obligations that are required to be settled in cash. Our contractual obligations as of December 31, 2020 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	$ 39,800	$ -	$ 39,800	$ -	$ -
Operating lease obligations	1,329	609	424	257	39
Total	$ 41,129	$ 609	$ 40,224	$ 257	$ 39

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, 2020.

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 that 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, 2020 or 2019.

Commodity Derivative Financial Instruments

Our ongoing operations expose us to changes in the market price for oil and natural gas. To mitigate the price risk associated with our operations, we, use commodity derivative financial instruments. From time to time, such instruments may include variable-to-fixed price swaps, costless collars, fixed-price contracts, and other contractual arrangements. We do not enter into derivative instruments for speculative purposes. The impact of these derivative instruments could affect the amount of revenue we ultimately record.

Derivative instruments are recognized at fair value. If a right of offset exists under master netting arrangements and certain other criteria are met, derivative assets and liabilities with the same counterparty are netted on the consolidated balance sheets. Gains and losses arising from changes in the fair value of derivatives are recognized on a net basis in the accompanying consolidated statements of operations within gain (loss) on commodity derivative instruments. Although these derivative instruments may expose us to credit risk, we mitigate that risk by monitoring the creditworthiness of our counterparties.

Warrant Liability

We account for the Warrants issued in connection with our IPO and private placement in accordance with the guidance contained in ASC 815-40 under which the Warrants do not meet the criteria for equity treatment and must be recorded as liabilities. Accordingly, we classify the warrants as liabilities at their fair value and adjust the warrants to fair value at each reporting period. This liability is subject to re-measurement at each balance sheet date until exercised, and any change in fair value is recognized in our statement of operations. The fair value of the warrants was estimated utilizing a binomial lattice model.

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. To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we use commodity derivative instruments to reduce our exposure to the price volatility of oil and natural gas. The counterparties to these contracts are unrelated third parties. The contracts settle monthly in cash based on a designated floating price. The designated floating price is based on the NYMEX benchmark for oil and natural gas. We have not designated any of our contracts as fair value or cash flow hedges. Accordingly, the changes in fair value of the contracts are included in net income in the period of the change.

As of December 31, 2020, we had a net liability derivative position related to our commodity price derivatives of $0.9 million. Utilizing actual derivative contractual volumes under our fixed price swap contracts and costless collar contracts as of December 31, 2020, a 10% increase in forward curves associated with the underlying commodity would have increased the net liability position to $1.7 million, an increase of $0.8 million, while a 10% decrease in forward curves associated with the underlying commodity would have created a net liability position of $0.2 million, a decrease of $0.8 million. However, any cash derivative gain or loss would be partially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

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, 2019, we received approximately 33%, 29%, and 18% of our revenue from ConocoPhillips, EOG, and Devon, respectively. For the year ended December 31, 2020, we received approximately 42%, 20%, and 16% 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, 2020, we had total borrowings under our Credit Facility of $39.8 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 $0.4 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 (As restated)

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 evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2020 with the participation, and under the supervision, of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon this evaluation, on March 12, 2021, we filed our original Annual Report on Form 10-K for the year ended December 31, 2020, at which time our Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2020, our disclosure controls and procedures were effective. Subsequently, and as a result of the material weakness in our internal control over financial reporting as described below, our management has concluded that our disclosure controls and procedures were not effective as of December 31, 2020.

Management's Report on Internal Control Over Financial Reporting (As revised)

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, 2020, 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 our assessments and those criteria, on March 12, 2021, we filed our original Annual Report on Form 10-K for the year ended December 31, 2020, at which time management determined that we maintained effective internal control over financial reporting as of December 31, 2020. Subsequently, our management has concluded that our internal control over financial reporting was not effective as of December 31, 2020, due to a material weakness in our internal control over financial reporting related to inaccurate accounting and reporting for warrants issued in connection with our initial public offering and private placement. Notwithstanding this material weakness, management has concluded that our audited financial statements included in this Annual Report on amended Form 10-K/A are fairly stated in all material respects in accordance with GAAP for each of the periods presented therein.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company's annual or interim financial statements will not be prevented or detected on a timely basis.

Our internal control over financial reporting did not detect the proper accounting and reporting for our warrants issued in connection with the Company's initial public offering in July 2017. Management identified this error when the SEC issued a Staff Statement on Accounting and Reporting Considerations for Warrants Issued by Special Purpose Acquisition Companies ("SPACs") dated April 12, 2021 (the "SEC Staff Statement"). The SEC Staff Statement addresses certain accounting and reporting considerations related to warrants of a kind similar to those we issued at the time of our initial public offering in July 2017. This control deficiency resulted in the Company having to restate its audited consolidated financial statements contained in its Annual Report on Form 10-K for the year ended December 31, 2020 and if not remediated, could result in a material misstatement to future annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, management has determined that this control deficiency constitutes a material weakness.

Plan for Remediation of the Material Weakness in Internal Control Over Financial Reporting

In response to this material weakness, the Company's management has expended, and will continue to expend, a substantial amount of effort and resources for the remediation and improvement of our internal control over financial reporting. While we have processes to properly identify and evaluate the appropriate accounting technical pronouncements and other literature for all significant or unusual transactions, we are improving these processes to ensure that the nuances of such transactions are effectively evaluated in the context of the increasingly complex accounting standards. Our plans at this time include acquiring enhanced access to accounting literature, research materials and documents and increased communication among our personnel and third-party professionals with whom we may consult regarding the application of complex accounting transactions. Our remediation plan can only be accomplished over time and will be continually reviewed to determine that it is achieving its objectives. We can offer no assurance that these initiatives will ultimately have the intended effects.

Changes in Internal Control Over Financial Reporting

Other than the changes made to remediate the material weakness described above, there has been no change in the Company's internal control over financial reporting that occurred during the quarter ended December 31, 2020 that have materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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 2021 annual meeting of the stockholders to be filed on or before April 30, 2021 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 2021 annual meeting of the stockholders to be filed on or before April 30, 2021 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 2021 annual meeting of the stockholders to be filed on or before April 30, 2021 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 2021 annual meeting of the stockholders to be filed on or before April 30, 2021 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 2021 annual meeting of the stockholders to be filed on or before April 30, 2021 and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES (As restated)

(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 (“Credit Agreement:) (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 Indemnity 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, dated as of December 10, 2016, by and among Royal Resources L.P., Riverbend Natural Resources, L.P., Blackstone Management Partners, LLC and Riverbend Oil & Gas, L.L.C. (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).
10.18†	Form of Performance Stock Unit Agreement (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 10-Q (File No. 001-38158) filed on May 5, 2020).
10.19	First Amendment to Credit Agreement, dated as of May 1, 2020 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 10-Q (File No. 001-38158) filed on May 5, 2020).
21.1	Subsidiaries of the Company (incorporated by reference to Exhibit 21.1 to the Company's Current Report on Form 10-K (File No. 001-38158) filed on March 12, 2021).
23.1*	Consent of Deloitte & Touche LLP
23.2	Consent of Ryder Scott Company, L.P. (incorporated by reference to Exhibit 23.2 to the Company's Current Report on Form 10-K (File No. 001-38158) filed on March 12, 2021).
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. (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 10-K (File No. 001-38158) filed on March 12, 2021).
101.INS*	Inline XBRL Instance Document.
101.SCH*	Inline XBRL Taxonomy Extension Schema Document.
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
104*	Cover Page Interactive Date File (embedded within the Inline XBRL document)

* 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: May 5, 2021

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, Director (Principal Executive Officer)	May 5, 2021
/s/ BRYAN C. GUNDERSON Bryan C. Gunderson	Chief Financial Officer (Principal Financial Officer)	May 5, 2021
/s/ STEPHEN J. PILATZKE Stephen J. Pilatzke	Chief Accounting Officer (Principal Accounting Officer)	May 5, 2021
/s/ CLAIRE HARVEY Claire Harvey	Chairman	May 5, 2021
/s/ STEVEN R. JONES Steven R. Jones	Director	May 5, 2021
/s/ WILLIAM D. ANDERSON William D. Anderson	Director	May 5, 2021
/s/ ALAN HIRSHBERG Alan Hirshberg	Director	May 5, 2021
/s/ ERIC C. BELZ Eric C. Belz	Director	May 5, 2021
/s/ ADAM M. JENKINS Adam M. Jenkins	Director	May 5, 2021
/s/ JONATHAN R. HAMILTON Jonathan R. Hamilton	Director	May 5, 2021

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

FALCON MINERALS CORPORATION

FALCON MINERALS CORPORATION
Report of Independent Registered Public Accounting Firm

To the shareholders and the Board of Directors 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, 2020 and 2019, the related consolidated statements of operations, cash flows, and shareholders' equity and partners' capital for each of the three years in the period ended December 31, 2020, 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, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America.

Restatement of the 2020, 2019 and 2018 Financial Statements

As discussed in Note 3 to the financial statements, the accompanying 2020, 2019 and 2018 financial statements have been restated to correct a misstatement.

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.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Proved Oil and Gas Properties, Depletion, Impairment, and Deferred Tax Asset Valuation Allowance - Crude Oil and Condensate, NGLs, and Natural Gas Reserves — Refer to Notes 2, 7, and 13 to the financial statements

Critical Audit Matter Description

The Company's proved oil and natural gas properties are depleted using the units of production method based on estimated proved oil and gas reserves developed under Securities and Exchange Commission guidelines and are evaluated for impairment by comparison of their carry value to the undiscounted value of net future cash flows of the underlying proved and unproved oil and natural gas reserves. The Company's deferred tax asset is evaluated for expected future realization through an undiscounted cash flow model using proved and unproved oil and gas reserves utilized in forecasting future taxable income. The development of the Company's oil and natural gas reserve quantities and the related future net cash flows requires management to make significant assumptions related to the five-year development rule for proved undeveloped reserves, future commodity prices and the existence and timing of forecasted production. The Company engages an independent reserves engineer to estimate proved and support in estimating unproved oil and natural gas reserve quantities using engineering data, including the existence and timing of forecasted production. Changes in these assumptions could have a significant impact on the amount of depletion, any proved oil and gas impairment, or the expected future realization of the deferred tax asset. The proved oil and gas properties balance, net of accumulated amortization, was $175.0 million as of December 31, 2020. Depletion, depreciation, and amortization was $14.1 million for the year ended December 31, 2020. No impairment was recognized during 2020. The deferred tax asset was $55.8 million as of December 31, 2020. No valuation allowance was recorded as of December 31, 2020.

Given the significant judgments made by management and the reserves engineer, performing audit procedures to evaluate the Company's oil and natural gas reserve quantities and the related net cash flows and future taxable income, including management's estimates and assumptions related to the five-year development rule, future commodity prices and the existence and timing of forecasted production, requires a high degree of auditor judgment.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant judgments and assumptions to oil and natural gas reserves quantities and estimates of the existence and timing of forecasted production and commodity price, included the following, among others:

- We tested the design and implementation of controls related to the Company's estimation of oil and natural gas reserve quantities and the related future net cash flows and future taxable income.
- We assessed management's reserve report assumptions related to the forecasted production, production taxes, commodity pricing and differential, and other such economic assumptions on the basis of the Company's historical financial operating data.
- We evaluated the reasonableness of management's development plan by comparing the forecasts to:
  - Historical conversions of proved undeveloped reserves as compared to the number of proved undeveloped locations forecasted to be developed in the next five years.
  - Communications between management and the independent reserve engineer.
  - Investor presentations related to rig count and development timing of the Company's major operators.
  - Publicly available data on the development status of certain wells reported to state regulatory agencies.
  - Our understanding obtained from inquiries with the Company's external reserve engineer.
  - The reserve report published by the Company's independent reserve engineer.
- We evaluated the Company's oil and natural gas reserve volumes by:
  - Comparing the Company's forecasted production to historical production volumes.
  - Evaluating the reasonableness of the forecasted production decline curves.
  - Understanding the experience, qualifications, and objectivity of the Company's reserve engineers.
  - Inspecting investor presentations and other disclosures from the Company's major operators related to well shut in and/or curtailment activity due to adverse economic conditions.
  - Assessing the oil and natural gas reserves volumes used in each accounting estimate for consistency.

Emphasis of Matter

As discussed and defined in Note 1 and Note 5 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 12, 2021 (May 5, 2021 as to the effects of the restatement to the 2020, 2019, and 2018 financial statements as discussed above and in Note 3 to the financial statements)

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

FALCON MINERALS CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands)

	As restated, See Note 3	
	December 31,	
	2020	2019
Assets:		
Current assets:		
Cash and cash equivalents	$ 2,724	$ 2,543
Account receivable	5,419	7,889
Prepaid expenses	766	1,182
Total current assets	8,909	11,614
Royalty interests in oil and natural gas properties, net of accumulated amortization of $144,445 and $130,342 respectively	207,505	219,192
Property and equipment, net of accumulated depreciation of $179 and $75	427	517
Deferred tax asset, net	55,773	56,352
Other assets	3,015	2,530
Total assets	$ 275,629	$ 290,205
Liabilities and shareholders' equity:		
Current liabilities:		
Accounts payable and accrued expenses	$ 1,540	$ 2,206
Other current liabilities	1,557	-
Total current liabilities	3,097	2,206
Credit facility	39,800	42,500
Warrant liability	3,503	8,631
Other liabilities	828	473
Total liabilities	47,228	53,810
Commitments and contingencies (See Note 15)		
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; 46,107,183 and 45,963,716 shares issued and outstanding as of December 31, 2020 and 2019, 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, 2020 and 2019	4	4
Additional paid in capital	121,053	117,561
Non-controlling interests	88,637	96,089
Retained earnings	18,702	22,736
Total shareholders' equity	228,401	236,395
Total liabilities, shareholders' equity	$ 275,629	$ 290,205

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)

	As restated, See Note 3		
	Year Ended December 31,		
	2020	2019	2018
Revenues:			
Oil and gas sales	$ 40,081	$ 68,463	$ 98,655
Gain (loss) on commodity derivative instruments	(1,200)	-	(1,456)
Total revenue	38,881	68,463	97,199
Operating expenses:			
Production and ad valorem taxes	2,807	4,262	5,143
Marketing and transportation	1,993	2,396	2,368
Amortization of royalty interests in oil and natural gas properties	14,103	12,737	16,962
General, administrative, and other	11,997	11,912	9,544
Total operating expenses	30,900	31,307	34,017
Operating income	7,981	37,156	63,182
Other income (expense):			
Gain on the sale of assets	-	-	41,382
Change in fair value of warrant liability	5,128	6,069	27,800
Other income	125	165	46
Interest expense	(2,197)	(2,489)	(2,350)
Total other income (expense)	3,056	3,745	66,878
Income before income taxes	11,037	40,901	130,060
Provision for income taxes	589	3,918	3,292
Income from continuing operations	10,448	36,983	126,768
Income from discontinued operations	-	-	2,139
Net income	10,448	36,983	128,907
Net income attributable to non-controlling interests	(2,748)	(16,564)	(10,982)
Net income attributable to common shareholders/unitholders	$ 7,700	$ 20,419	$ 117,925
Earnings per common share:			
Common shares - basic	$ 0.17	$ 0.44	$ 0.81
Common shares - diluted	$ 0.11	$ 0.39	$ 0.53
Weighted average number of shares outstanding:			
Common shares - basic	46,031	45,893	45,855
Common shares - diluted	86,031	85,893	85,855

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

FALCON MINERALS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	As restated, See Note 3		
	Year Ended December 31,		
	2020	2019	2018
Cash flow from operating activities:			
Net income	$ 10,448	$ 36,983	$ 128,907
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Gain on sale of assets	-	-	(41,382)
Unrealized (gain) loss on commodity derivative instruments	944	-	1,151
Amortization of royalty interests in oil and natural gas properties	14,103	12,737	18,536
Change in fair value of warrant liability	(5,128)	(6,069)	(27,800)
Amortization of right-of-use assets	492	-	-
Accretion of asset retirement obligation	-	-	7
Amortization of debt issuance costs	658	643	457
Deferred rent	-	473	-
Depreciation of property and equipment	104	75	-
Share based compensation	3,480	2,548	-
Deferred income taxes	579	2,421	2,285
Cash paid to settle derivatives	-	-	(1,151)
Changes in operating assets and liabilities			
Accounts receivable	2,470	3,383	1,882
Prepaid expenses	416	342	(278)
Other assets	-	10	(182)
Accounts payable and accrued expenses	(553)	1,683	(4,399)
Other liabilities	(579)	-	(147)
Net cash provided by operating activities	27,434	55,229	77,886
Cash flows from investing activities:			
Additions to oil and natural gas properties	-	-	(523)
Cash acquired in the Transactions	-	-	2,920
Proceeds from the sale of assets	-	-	121,130
Acquisition of oil and natural gas properties	(2,417)	(22,761)	(1,215)
Purchase of property and equipment	(14)	(592)	-
Net cash provided by (used in) investing activities	(2,431)	(23,353)	122,312
Cash flows from financing activities:			
Distributions to partners	-	-	(143,788)
Distribution of subsidiaries	-	-	(7,125)
Contributions	-	-	(8)
Proceeds from long-term debt	10,800	39,000	-
Repayments of long-term debt	(13,500)	(17,500)	(44,000)
Deferred financing fees	(88)	-	-
Dividends paid	(11,734)	(30,293)	(4,356)
Distributions to non-controlling interests	(10,200)	(27,703)	(4,101)
Dividend equivalent rights paid	(100)	(154)	-
Net cash used in financing activities	(24,822)	(36,650)	(203,378)
Net increase (decrease) in cash and cash equivalents	181	(4,774)	(3,180)
Cash and cash equivalents, beginning of period	2,543	7,317	10,497
Cash and cash equivalents, end of period	$ 2,724	$ 2,543	$ 7,317
Supplemental disclosure of cash flow information:			
Cash paid for interest	$ 1,539	1,846	1,834
Cash paid for income taxes	-	1,260	1,350
Non-cash investing and financing activities:			
Accrued bonus paid in stock	112	-	-
Right-of-use assets obtained in exchange for operating leases	1,547	-	-
Valuation of warrants related to the Transactions	-	-	42,500
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

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)

	As restated, See Note 3								
	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 January 1, 2018	-	$ -	-	$ -	$ -	$ 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	115,167	(225,737)	99,756	-	(10,805)
Net income post Transactions	-	-	-	-	-	-	10,867	36,966	47,833
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	$ 115,167	$ -	$ 107,228	$ 32,610	$ 255,014
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)	-	-	-	-	-	-	-	(30,293)	(30,293)
Net income	-	-	-	-	-	-	16,564	20,419	36,983
Balance at December 31, 2019	45,964	$ 5	40,000	$ 4	$ 117,561	$ -	$ 96,089	$ 22,736	$ 236,395
Vested restricted stock grants	143	-	-	-	-	-	-	-	-
Stock-based compensation	-	-	-	-	3,592	-	-	-	3,592
Dividend equivalent rights paid	-	-	-	-	(100)	-	-	-	(100)
Distributions to non-controlling interests	-	-	-	-	-	-	(10,200)	-	(10,200)
Dividends to shareholders ($0.255 per share)	-	-	-	-	-	-	-	(11,734)	(11,734)
Net income	-	-	-	-	-	-	2,748	7,700	10,448
Balance at December 31, 2020	46,107	$ 5	40,000	$ 4	$ 121,053	$ -	$ 88,637	$ 18,702	$ 228,401

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 80,000 gross unit 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 NGLs 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, and 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, 2020, and December 31, 2019, the Company had not recorded any reserves for uncollectible amounts or deemed any amounts to be uncollectible.

Commodity Derivative Financial Instruments

The Company's ongoing operations expose it to changes in the market price for oil and natural gas. To mitigate the price risk associated with its operations, the Company uses commodity derivative financial instruments. From time to time, such instruments may include variable-to-fixed-price swaps, costless collars, fixed-price contracts, and other contractual arrangements. The Company does not enter into derivative instruments for speculative purposes.

Derivative instruments are recognized at fair value. If a right of offset exists under master netting arrangements and certain other criteria are met, derivative assets and liabilities with the same counterparty are netted on the consolidated balance sheets. The Company does not specifically designate derivative instruments as fair value or cash flow hedges, even though they reduce its exposure to changes in oil and natural gas prices; therefore, gains and losses arising from changes in the fair value of the derivative instruments are recognized on a net basis in the accompanying consolidated statements of operations within Gain (loss) on commodity derivative instruments.

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, 2020 or 2019.

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, 2020 and 2019.

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 $1.8 million and $2.4 million as of December 31, 2020 and 2019, respectively. The costs are associated with the Company's credit agreement and are being amortized over the term of the credit agreement. In May 2020, the Company entered into an amendment to the Credit Facility and capitalized an additional $0.1 million of associated costs which will be amortized over the remainder of the term of the Credit Facility.

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. The Company's Public Warrants also approximate their fair value because the publicly quoted prices on active, liquid and visible markets such as stock exchanges (Level 1). Because the Credit Facility (as defined in "Note 8 – Debt – Falcon Credit Facility" below) has a market rate of interest, its carrying amount approximated fair value (Level 2). The Company's commodity derivative instruments are classified within Level 2. The fair values of the Company's commodity derivative instruments are based upon inputs that are either readily available in the public market, such as oil and natural gas futures prices, publicly stated stock prices, volatility factors and discount rates, or can be corroborated from active markets. The Company's Private Placement Warrant liability is classified within Level 3 due to the significant unobservable inputs utilized in determining the fair value. See "Note 9 – Warrants" for further information.

Warrant Liability

The Company issued the Public and Private Placement Warrants in connection with its initial public offering in 2017. Warrants are accounted for in accordance with applicable accounting guidance provided in ASC 815-40 – "Derivatives and Hedging – Contracts in Entity's Own Equity ("ASC 815"), as either liabilities or as equity instruments depending on the specific terms of the warrant agreement. The Company's warrants were classified as liabilities and are recorded at fair value at issuance and are subject to remeasurement at each reporting period. Any change in fair value has been recorded in the statement of operations.

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 years ended December 31, 2020 and 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, 2020. 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.

Share-Based Compensation

Share-based compensation awards are measured at fair value on the date of grant and are expensed, net of any actual forfeitures, over the required service period. See "Note 10—Share-Based Compensation" for additional information.

Segment Reporting

The Company derives revenue from 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 Financial Accounting Standards Board ("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 recognized 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 was effective for fiscal years beginning after December 15, 2019, with early adoption permitted. The Company adopted the modified retrospective approach upon adoption of the new guidance on the effective date of January 1, 2020. Please see "Note 4—Impact of ASC 842 Adoption" for further details related to the Company's adoption of this standard.

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 was effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. The adoption of this standard did not have a material impact on the Company's financial statements.

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 does not believe the adoption of this standard will have an impact on its financial statements.

In March 2020, the FASB issued new guidance which provides optional expedients and exceptions, for a limited time, to ease the potential burden in accounting for or recognizing the effects of reference rate reform on financial reporting. The standard was effective upon issuance and generally can be applied through December 31, 2022. An entity may elect to apply the amendments for contract modifications as of any date from the beginning of an interim period that includes or is subsequent to March 12, 2020, or prospectively from a date within an interim period that includes or is subsequent to March 12, 2020, up to the date that the financial statements are available to be issued. Once elected the amendments in this update must be applied prospectively for all eligible contract modifications. Management has elected to apply this update subsequent to March 12, 2020. Management is currently evaluating the impact of this guidance but does not expect this update to have a material impact on the Company's financial statements.

Note 3—Restatement of Previously Issued Consolidated Financial Statements

Subsequent to the issuance of the Company's consolidated financial statements as of December 31, 2020 and 2019 and for the years ended December 31, 2020, 2019 and 2018, the SEC Division of Corporation of Finance released Staff Statement on Accounting and Reporting Considerations for Warrants Issued by Special Purpose Acquisition Companies ("SPACs") (the "Statement") on April 12, 2021. Upon review and analysis of the Statement, management determined that the Company's Public Warrants and Private Placement Warrants issued in connection with the closing of the Osprey initial public offering in July 2017 (see Notes 1 and 9) do not meet the scope exception from derivative accounting prescribed by ASC 815-40. Accordingly, the Warrants should have been recognized by the Company at fair value as of August 23, 2018, the Closing Date, and classified as a liability, rather than equity in the Company's previously reported consolidated balance sheets as of December 31, 2020 and 2019. Thereafter, the change in fair value of the outstanding Warrants should have been recognized as a derivative gain (loss) each reporting period in the Company's consolidated statement of operations. The fair value of the Warrants that should have been recorded as of the Closing Date on August 23, 2018 was $42,500 thousand. The fair value of the Warrants as of December 31, 2020 and 2019 amounted to $3,503 and $8,631 thousand, respectively. The change in fair value amounted to $5,128, $6,069, and $27,800 thousand for the years ended December 31, 2020, 2019 and 2018, respectively. Management concluded the effect of this error on the Company's previously reported consolidated financial statements is material and, as such, the accompanying consolidated financial statements as of December 31, 2020 and 2019 and for the years ended December 31, 2020, 2019 and 2018, and accompanying notes hereto have been restated from the amounts previously reported to give effect to the correction of this error (the "Restatement").

The following tables reflect the impact of the Restatement of the Company's previously reported consolidated financial statements:

Falcon Minerals Corporation
Consolidated Balance Sheet
(In thousands, except share amounts)

	December 31, 2020		
	As Previously Reported	Adjustments	As Restated
Assets:			
Current assets:			
Cash and cash equivalents	$ 2,724	$ -	$ 2,724
Account receivable	5,419	-	5,419
Prepaid expenses	766	-	766
Total current assets	8,909	-	8,909
Royalty interests in oil and natural gas properties, net of accumulated amortization of $144,445	207,505	-	207,505
Property and equipment, net of accumulated depreciation of $179	427	-	427
Deferred tax asset, net	55,773	-	55,773
Other assets	3,015	-	3,015
Total assets	$ 275,629	$ -	$ 275,629
Liabilities and shareholders' equity:			
Current liabilities:			
Accounts payable and accrued expenses	$ 1,540	$ -	$ 1,540
Other current liabilities	1,557	-	1,557
Total current liabilities	3,097	-	3,097
Credit facility	39,800	-	39,800
Warrant liability	-	3,503	3,503
Other liabilities	828	-	828
Total liabilities	43,725	3,503	47,228
Commitments and contingencies			
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; 46,107,183 shares issued and outstanding as of December 31, 2020	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, 2020	4	-	4
Additional paid in capital	123,457	(2,404)	121,053
Non-controlling interests	108,438	(19,801)	88,637
Retained earnings	-	18,702	18,702
Total shareholders' equity	231,904	(3,503)	228,401
Total liabilities, shareholders' equity	$ 275,629	$ -	$ 275,629

Falcon Minerals Corporation
Consolidated Balance Sheet
(In thousands, except share amounts)

	December 31, 2019		
	As Previously Reported	Adjustments	As Restated
Assets:			
Current assets:			
Cash and cash equivalents	$ 2,543	$ -	$ 2,543
Account receivable	7,889	-	7,889
Prepaid expenses	1,182	-	1,182
Total current assets	11,614	-	11,614
Royalty interests in oil and natural gas properties, net of accumulated amortization of $130,342	219,192	-	219,192
Property and equipment, net of accumulated depreciation of $75	517	-	517
Deferred tax asset, net	56,352	-	56,352
Other assets	2,530	-	2,530
Total assets	$ 290,205	$ -	$ 290,205
Liabilities and shareholders' equity:			
Current liabilities:			
Accounts payable and accrued expenses	$ 2,206	$ -	$ 2,206
Other current liabilities	-	-	-
Total current liabilities	2,206	-	2,206
Credit facility	42,500	-	42,500
Warrant liability	-	8,631	8,631
Other liabilities	473	-	473
Total liabilities	45,179	8,631	53,810
Commitments and contingencies			
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 shares issued and outstanding as of December 31, 2019	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	4	-	4
Additional paid in capital	129,127	(11,566)	117,561
Non-controlling interests	115,890	(19,801)	96,089
Retained earnings	-	22,736	22,736
Total shareholders' equity	245,026	(8,631)	236,395
Total liabilities, shareholders' equity	$ 290,205	$ -	$ 290,205

Falcon Minerals Corporation
Consolidated Statement of Operations
(In thousands, except share amounts)

	Year ended December 31, 2020		
	As Previously Reported	Adjustments	As Restated
Revenues:			
Oil and gas sales	$ 40,081	$ -	$ 40,081
Gain (loss) on commodity derivative instruments	(1,200)	-	(1,200)
Total revenue	38,881	-	38,881
Operating expenses:			
Production and ad valorem taxes	2,807	-	2,807
Marketing and transportation	1,993	-	1,993
Amortization of royalty interests in oil and natural gas properties	14,103	-	14,103
General, administrative, and other	11,997	-	11,997
Total operating expenses	30,900	-	30,900
Operating income	7,981	-	7,981
Other income (expense):			
Gain on the sale of assets	-	-	-
Change in fair value of warrant liability	-	5,128	5,128
Other income	125	-	125
Interest expense	(2,197)	-	(2,197)
Total other income (expense)	(2,072)	5,128	3,056
Income before income taxes	5,909	5,128	11,037
Provision for income taxes	589	-	589
Income from continuing operations	5,320	5,128	10,448
Income from discontinued operations	-	-	-
Net income	5,320	5,128	10,448
Net income attributable to non-controlling interests	(2,748)	-	(2,748)
Net income attributable to common shareholders/unitholders	$ 2,572	$ 5,128	$ 7,700
Earnings per common share:			
Common shares - basic	$ 0.05	$ 0.12	$ 0.17
Common shares - diluted	$ 0.05	$ 0.06	$ 0.11
Weighted average number of shares outstanding:			
Common shares - basic	46,031	-	46,031
Common shares - diluted	46,031	40,000	86,031

Falcon Minerals Corporation
Consolidated Statement of Operations
(In thousands, except share amounts)

	Year ended December 31, 2019		
	As Previously Reported	Adjustments	As Restated
Revenues:			
Oil and gas sales	$ 68,463	$ -	$ 68,463
Gain (loss) on commodity derivative instruments	-	-	-
Total revenue	68,463	-	68,463
Operating expenses:			
Production and ad valorem taxes	4,262		4,262
Marketing and transportation	2,396		2,396
Amortization of royalty interests in oil and natural gas properties	12,737		12,737
General, administrative, and other	11,912		11,912
Total operating expenses	31,307	-	31,307
Operating income	37,156	-	37,156
Other income (expense):			
Gain on the sale of assets	-		-
Change in fair value of warrant liability	-	6,069	6,069
Other income	165		165
Interest expense	(2,489)		(2,489)
Total other income (expense)	(2,324)	6,069	3,745
Income before income taxes	34,832	6,069	40,901
Provision for income taxes	3,918		3,918
Income from continuing operations	30,914	6,069	36,983
Income from discontinued operations	-		-
Net income	30,914	6,069	36,983
Net income attributable to non-controlling interests	(16,564)		(16,564)
Net income attributable to common shareholders/unitholders	$ 14,350	$ 6,069	$ 20,419
Earnings per common share:			
Common shares - basic	$ 0.31	$ 0.13	$ 0.44
Common shares - diluted	$ 0.31	$ 0.08	$ 0.39
Weighted average number of shares outstanding:			
Common shares - basic	45,893	-	45,893
Common shares - diluted	45,893	40,000	85,893

Falcon Minerals Corporation
Consolidated Statement of Operations
(In thousands, except share amounts)

	Year ended December 31, 2018		
	As Previously Reported	Adjustments	As Restated
Revenues:			
Oil and gas sales	$ 98,655	$ -	$ 98,655
Gain (loss) on commodity derivative instruments	(1,456)	-	(1,456)
Total revenue	97,199	-	97,199
Operating expenses:			
Production and ad valorem taxes	5,143		5,143
Marketing and transportation	2,368		2,368
Amortization of royalty interests in oil and natural gas properties	16,962		16,962
General, administrative, and other	9,544		9,544
Total operating expenses	34,017	-	34,017
Operating income	63,182	-	63,182
Other income (expense):			
Gain on the sale of assets	41,382		41,382
Change in fair value of warrant liability	-	27,800	27,800
Other income	46		46
Interest expense	(2,350)		(2,350)
Total other income (expense)	39,078	27,800	66,878
Income before income taxes	102,260	27,800	130,060
Provision for income taxes	3,292		3,292
Income from continuing operations	98,968	27,800	126,768
Income from discontinued operations	2,139		2,139
Net income	101,107	27,800	128,907
Net income attributable to non-controlling interests	(10,982)		(10,982)
Net income attributable to common shareholders/unitholders	$ 90,125	$ 27,800	$ 117,925
Earnings per common share:			
Common shares - basic	$ 0.20	$ 0.61	$ 0.81
Common shares - diluted	$ 0.20	$ 0.33	$ 0.53
Weighted average number of shares outstanding:			
Common shares - basic	45,855	-	45,855
Common shares - diluted	45,855	40,000	85,855

Falcon Minerals Corporation
Consolidated Statement of Cash Flows
(In thousands, except share amounts)

	Year ended December 31, 2020		
	As Previously Reported	**Adjustments**	**As Restated**
Cash flow from operating activities:			
Net income	$ 5,320	$ 5,128	$ 10,448
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Gain on sale of assets	-		-
Unrealized (gain) loss on commodity derivative instruments	944		944
Change in fair value of warrant liability	-	(5,128)	(5,128)
Amortization of royalty interests in oil and natural gas properties	14,103		14,103
Amortization of right-of-use assets	492		492
Accretion of asset retirement obligation	-		-
Amortization of debt issuance costs	658		658
Deferred rent	-		-
Depreciation of property and equipment	104		104
Share based compensation	3,480		3,480
Deferred income taxes	579		579
Cash paid to settle derivatives	-		-
Changes in operating assets and liabilities			-
Accounts receivable	2,470		2,470
Prepaid expenses	416		416
Other assets	-		-
Accounts payable and accrued expenses	(553)		(553)
Other liabilities	(579)		(579)
Net cash provided by operating activities	27,434	-	27,434
Cash flows from investing activities:			
Additions to oil and natural gas properties	-		-
Cash acquired in the Transactions	-		-
Proceeds from the sale of assets	-		-
Acquisition of oil and natural gas properties	(2,417)		(2,417)
Purchase of property and equipment	(14)		(14)
Net cash provided by (used in) investing activities	(2,431)	-	(2,431)
Cash flows from financing activities:			
Distributions to partners	-		-
Distribution of subsidiaries	-		-
Contributions	-		-
Proceeds from long-term debt	10,800		10,800
Repayments of long-term debt	(13,500)		(13,500)
Deferred financing fees	(88)		(88)
Dividends paid	(11,734)		(11,734)
Distributions to non-controlling interests	(10,200)		(10,200)
Dividend equivalent rights paid	(100)		(100)
Net cash used in financing activities	(24,822)	-	(24,822)
Net increase (decrease) in cash and cash equivalents	181	-	181
Cash and cash equivalents, beginning of period	2,543		2,543
Cash and cash equivalents, end of period	$ 2,724	$ -	$ 2,724
Supplemental disclosure of cash flow information:			
Cash paid for interest	$ 1,539	$ -	$ 1,539
Cash paid for income taxes	-	-	-
Non-cash investing and financing activities:			
Accrued bonus paid in stock	112	-	112
Right-of-use assets obtained in exchange for operating leases	1,547	-	1,547

Falcon Minerals Corporation
Consolidated Statement of Cash Flows
(In thousands, except share amounts)

	Year ended December 31, 2019		
	As Previously Reported	Adjustments	As Restated
Cash flow from operating activities:			
Net income	$ 30,914	$ 6,069	$ 36,983
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Gain on sale of assets	-		-
Unrealized (gain) loss on commodity derivative instruments	-		-
Change in fair value of warrant liability	-	(6,069)	(6,069)
Amortization of royalty interests in oil and natural gas properties	12,737		12,737
Amortization of right-of-use assets	-		-
Accretion of asset retirement obligation	-		-
Amortization of debt issuance costs	643		643
Deferred rent	473		473
Depreciation of property and equipment	75		75
Share based compensation	2,548		2,548
Deferred income taxes	2,421		2,421
Cash paid to settle derivatives	-		-
Changes in operating assets and liabilities			-
Accounts receivable	3,383		3,383
Prepaid expenses	342		342
Other assets	10		10
Accounts payable and accrued expenses	1,683		1,683
Other liabilities	-		-
Net cash provided by operating activities	55,229	-	55,229
Cash flows from investing activities:			
Additions to oil and natural gas properties	-		-
Cash acquired in the Transactions	-		-
Proceeds from the sale of assets	-		-
Acquisition of oil and natural gas properties	(22,761)		(22,761)
Purchase of property and equipment	(592)		(592)
Net cash provided by (used in) investing activities	(23,353)	-	(23,353)
Cash flows from financing activities:			
Distributions to partners	-		-
Distribution of subsidiaries	-		-
Contributions	-		-
Proceeds from long-term debt	39,000		39,000
Repayments of long-term debt	(17,500)		(17,500)
Deferred financing fees	-		-
Dividends paid	(30,293)		(30,293)
Distributions to non-controlling interests	(27,703)		(27,703)
Dividend equivalent rights paid	(154)		(154)
Net cash used in financing activities	(36,650)	-	(36,650)
Net increase (decrease) in cash and cash equivalents	(4,774)	-	(4,774)
Cash and cash equivalents, beginning of period	7,317		7,317
Cash and cash equivalents, end of period	$ 2,543	$ -	$ 2,543
Supplemental disclosure of cash flow information:			
Cash paid for interest	$ 1,846	$ -	$ 1,846
Cash paid for income taxes	1,260	-	1,260

Falcon Minerals Corporation
Consolidated Statement of Cash Flows
(In thousands, except share amounts)

	Year ended December 31, 2018		
	As Previously Reported	**Adjustments**	**As Restated**
Cash flow from operating activities:			
Net income	$ 101,107	$ 27,800	$ 128,907
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Gain on sale of assets	(41,382)		(41,382)
Unrealized (gain) loss on commodity derivative instruments	1,151		1,151
Change in fair value of warrant liability	-	(27,800)	(27,800)
Amortization of royalty interests in oil and natural gas properties	18,536		18,536
Amortization of right-of-use assets	-		-
Accretion of asset retirement obligation	7		7
Amortization of debt issuance costs	457		457
Deferred rent	-		-
Depreciation of property and equipment	-		-
Share based compensation	-		-
Deferred income taxes	2,285		2,285
Cash paid to settle derivatives	(1,151)		(1,151)
Changes in operating assets and liabilities			-
Accounts receivable	1,882		1,882
Prepaid expenses	(278)		(278)
Other assets	(182)		(182)
Accounts payable and accrued expenses	(4,399)		(4,399)
Other liabilities	(147)		(147)
Net cash provided by operating activities	77,886	-	77,886
Cash flows from investing activities:			
Additions to oil and natural gas properties	(523)		(523)
Cash acquired in the Transactions	2,920		2,920
Proceeds from the sale of assets	121,130		121,130
Acquisition of oil and natural gas properties	(1,215)		(1,215)
Purchase of property and equipment	-		-
Net cash provided by (used in) investing activities	122,312	-	122,312
Cash flows from financing activities:			
Distributions to partners	(143,788)		(143,788)
Distribution of subsidiaries	(7,125)		(7,125)
Contributions	(8)		(8)
Proceeds from long-term debt	-		-
Repayments of long-term debt	(44,000)		(44,000)
Deferred financing fees	-		-
Dividends paid	(4,356)		(4,356)
Distributions to non-controlling interests	(4,101)		(4,101)
Dividend equivalent rights paid	-		-
Net cash used in financing activities	(203,378)	-	(203,378)
Net increase (decrease) in cash and cash equivalents	(3,180)	-	(3,180)
Cash and cash equivalents, beginning of period	10,497		10,497
Cash and cash equivalents, end of period	$ 7,317	$ -	$ 7,317
Supplemental disclosure of cash flow information:			
Cash paid for interest	$ 1,834	$ -	$ 1,834
Cash paid for income taxes	1,350	-	1,350
Non-cash investing and financing activities:			
Initial valuation of warrants related to the Transactions	-	42,500	42,500
Credit facility prior to the Transactions	38,000	-	38,000
Distribution of long-term debt to non-acquired entities prior to the Transactions	31,000	-	31,000
Deferred financing fees prior to the Transactions	3,214	-	3,214
Deferred tax asset related to the Transactions	60,603	-	60,603

Falcon Minerals Corporation
Statement of Shareholders' Equity and Partners' Capital
(In thousands, except per share amounts)

	Class A Common Stock		Class C Common Stock						
As Previously Reported	Shares	Amount	Shares	Amount	Additional Paid In Capital	Partners' Capital	Non-controlling interests	Retained Earnings	Total Stockholder's Equity
Balance at January 1, 2020	45,964	$ 5	40,000	$ 4	$ 129,127	$ -	$ 115,890	$ -	$ 245,026
Vested restricted stock grants	143	-	-	-	-	-	-	-	-
Stock-based compensation	-	-	-	-	3,592	-	-	-	3,592
Dividend equivalent rights paid	-	-	-	-	(100)	-	-	-	(100)
Distributions to non-controlling interests	-	-	-	-	-	-	(10,200)	-	(10,200)
Dividends to shareholders ($0.255 per share)	-	-	-	-	(9,162)	-	-	(2,572)	(11,734)
Net income	-	-	-	-	-	-	2,748	2,572	5,320
Balance at December 31, 2020	46,107	$ 5	40,000	$ 4	$ 123,457	$ -	$ 108,438	$ -	$ 231,904
Adjustments									
Balance at January 1, 2020	$ -	$ -	$ -	$ -	$ (11,566)	$ -	$ (19,801)	$ 22,736	$ (8,631)
Vested restricted stock grants	-	-	-	-	-	-	-	-	-
Stock-based compensation	-	-	-	-	-	-	-	-	-
Dividend equivalent rights paid	-	-	-	-	-	-	-	-	-
Distributions to non-controlling interests	-	-	-	-	-	-	-	-	-
Dividends to shareholders ($0.255 per share)	-	-	-	-	9,162	-	-	(9,162)	-
Net income	-	-	-	-	-	-	-	5,128	5,128
Balance at December 31, 2020	-	$ -	-	$ -	$ (2,404)	$ -	$ (19,801)	$ 18,702	$ (3,503)
As Restated									
Balance at January 1, 2020	45,964	$ 5	40,000	$ 4	$ 117,561	$ -	$ 96,089	$ 22,736	$ 236,395
Vested restricted stock grants	143	-	-	-	-	-	-	-	-
Stock-based compensation	-	-	-	-	3,592	-	-	-	3,592
Dividend equivalent rights paid	-	-	-	-	(100)	-	-	-	(100)
Distributions to non-controlling interests	-	-	-	-	-	-	(10,200)	-	(10,200)
Dividends to shareholders ($0.255 per share)	-	-	-	-	-	-	-	(11,734)	(11,734)
Net income	-	-	-	-	-	-	2,748	7,700	10,448
Balance at December 31, 2020	46,107	$ 5	40,000	$ 4	$ 121,053	$ -	$ 88,637	$ 18,702	$ 228,401

Falcon Minerals Corporation
Statement of Shareholders' Equity and Partners' Capital
(In thousands, except per share amounts)

	Class A Common Stock		Class C Common Stock						
As Previously Reported	Shares	Amount	Shares	Amount	Additional Paid In Capital	Partners' Capital	Non-controlling interests	Retained Earnings	Total Stockholder's Equity
Balance at January 1, 2019	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
Adjustments									
Balance at January 1, 2019	$ -	$ -	$ -	$ -	$ (22,699)	$ -	$ (19,801)	$ 27,800	$ (14,700)
Vested restricted stock grants	-	-	-	-	-	-	-	-	-
Stock-based compensation	-	-	-	-	-	-	-	-	-
Dividend equivalent rights paid	-	-	-	-	-	-	-	-	-
Distributions to non-controlling interests	-	-	-	-	-	-	-	-	-
Dividends to shareholders ($0.66 per share)	-	-	-	-	11,133	-	-	(11,133)	-
Net income	-	-	-	-	-	-	-	6,069	6,069
Balance at December 31, 2019	-	$ -	-	$ -	$ (11,566)	$ -	$ (19,801)	$ 22,736	$ (8,631)
As Restated									
Balance at January 1, 2019	45,855	$ 5	40,000	$ 4	$ 115,167	$ -	$ 107,228	$ 32,610	$ 255,014
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)	-	-	-	-	-	-	-	(30,293)	(30,293)
Net income	-	-	-	-	-	-	16,564	20,419	36,983
Balance at December 31, 2019	45,964	$ 5	40,000	$ 4	$ 117,561	$ -	$ 96,089	$ 22,736	$ 236,395

Falcon Minerals Corporation
Statement of Shareholders' Equity and Partners' Capital
(In thousands, except per share amounts)

	Class A Common Stock		Class C Common Stock						
As Previously Reported	Shares	Amount	Shares	Amount	Additional Paid In Capital	Partners' Capital	Non-controlling interests	Retained Earnings	Total Stockholder's Equity
Balance at January 1, 2018	-	$ -	-	$ -	$ -	$ 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
Adjustments									
Balance at January 1, 2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distributions to partners	-	-	-	-	-	-	-	-	-
Net income prior to Transactions	-	-	-	-	-	-	-	-	-
Recapitalization in connection with the Transactions	-	-	-	-	(22,699)	-	(19,801)	-	(42,500)
Net income post Transactions	-	-	-	-	-	-	-	27,800	27,800
Distributions to non-controlling interests	-	-	-	-	-	-	-	-	-
Dividends to shareholders ($0.095 per share)	-	-	-	-	-	-	-	-	-
Balance at December 31, 2018	-	$ -	-	$ -	$ (22,699)	$ -	$ (19,801)	$ 27,800	$ (14,700)
As Restated									
Balance at January 1, 2018	-	$ -	-	$ -	$ -	$ 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	115,167	(225,737)	99,756	-	(10,805)
Net income post Transactions	-	-	-	-	-	-	10,867	36,966	47,833
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	$ 115,167	$ -	$ 107,228	$ 32,610	$ 255,014

Note 4—Impact of ASC 842 Adoption

On January 1, 2020, the Company adopted ASU 2016-02, Leases ("ASC 842") using the modified retrospective method. The Company elected the package of practical expedients upon transition which will retain the lease classification for leases and any unamortized initial direct costs that existed prior to the adoption of this standard.

The adoption of the standard resulted in the recognition of operating lease right-of-use ("ROU") assets and operating lease liabilities on the consolidated balance sheet as of January 1, 2020. ROU assets represent less than 1% of the Company's total assets and lease liabilities represent less than 5% of the Company's total liabilities as of December 31, 2020 and were not considered material to the Company. The Company did not recognize a material cumulative adjustment to the consolidated statement of shareholders' equity and did not have any material changes in the timing of expense recognition or the Company's accounting policies. The standard had no impact on the Company's debt covenant compliance under existing agreements.

This ASU requires the Company to identify its contractual arrangements that contain leases at the inception of such arrangements. Specifically, the Company considered whether it can control the underlying asset and have the right to obtain substantially all of the economic benefits or outputs from the asset. The Company's leases are long-term operating leases with fixed payment terms and will terminate at various dates through April 2027. The Company's ROU assets represent its right to use an underlying asset for the lease term, and its operating lease liabilities represent its obligation to make lease payments. ROU operating assets and operating lease liabilities are included in the accompanying consolidated balance sheet as of December 31, 2020.

ROU assets are recognized at commencement date and consist of the present value of the remaining lease payments over the lease term, initial direct costs, prepaid lease payments less any lease incentives. Operating lease liabilities are recognized at commencement date based on the present value of the remaining lease payments over the lease term. The Company uses the implicit rate, when readily determinable, or its incremental borrowing rate based on the information available at the commencement date to determine the present value of lease payments. Since the Company's leases do not provide an implicit rate that can readily be determined, the Company used a discount rate based on its incremental borrowing rate, which is determined by the information available in our Credit Facility. The incremental borrowing rate reflects the estimated rate of interest the Company would pay to borrow, on a collateralized basis over a similar term, an amount equal to the least payments in a similar economic environment.

Our lease obligations are primarily comprised of the main office spaces used for operations and are recorded as General, administrative, and other expenses in the Consolidated Statement of Operations. As of December 31, 2020, our lease obligations were classified as operating leases. The Company's rental costs associated with these office spaces was $0.6 million for the year ended December 31, 2020.

The lease terms may include periods covered by options to extend the lease when it is reasonably certain that the Company will exercise that option and periods covered by options to terminate the lease when it is not reasonably certain that the Company will exercise that option. Lease cost for lease obligations is recognized on a straight-line basis over the lease term. In the event that the Company's assumptions and expectations change, it may have to revise its ROU assets and operating lease liabilities. As of December 31, 2020, the weighted average remaining lease term is 3.4 years, and the weighted average discount rate is 4.21%.

As of December 31, 2020, the Company had ROU assets of $1.1 million recorded as Other Assets, $0.6 million of corresponding obligations recorded as Other Current Liabilities and $0.8 million of corresponding obligations recorded as Other Liabilities on the Company's consolidated balance sheet.

Under ASC 840, rent expense recorded for the years ended December 31, 2019 and 2018 was $0.3 million, and less than $0.1 million, respectively.

As of December 31, 2020, the undiscounted cash flows for operating lease liabilities are as follows (in thousands):

	Payments Due by Period						
	Total	**2021**	**2022**	**2023**	**2024**	**2025**	**Thereafter**
Lease obligations	$ 1,329	$ 609	$ 228	$ 196	$ 199	$ 58	$ 39
Total	$ 1,329	$ 609	$ 228	$ 196	$ 199	$ 58	$ 39

Under ASC 842, as of December 31, 2020, the Company has operating lease obligations expiring at various dates. There is an immaterial difference between undiscounted cash flows for operating leases and our $1.3 million of lease obligations due to the impact of the applicable discount rate.

Note 5 – 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, 2020, 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
Revenues:	
Oil and gas sales	$ 5,401
Expenses:	
Production and ad valorem taxes	484
Lease operating expenses	510
Transportation and marketing	333
Depreciation, depletion, and amortization	1,574
General, administrative, and other	324
Total expenses	3,225
Operating income	
Other income (expense):	
Other income	2
Interest expense	(39)
Total other income (expense)	(37)
Net income	$ 2,139

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

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

Note 6—Commodity Derivative Financial Instruments

The Company's ongoing operations expose it to changes in the market price for oil and natural gas. To mitigate the inherent commodity price risk associated with its operations, the Company uses oil and natural gas commodity derivative instruments. From time to time, such instruments may include variable-to-fixed-price swaps, costless collars, fixed-price contracts, and other contractual arrangements. The Company enters into oil and natural gas derivative contracts that contain netting arrangements with each counterparty. The Company does not enter into derivative instruments for speculative purposes.

As of December 31, 2020, the Company's open derivative contracts consisted of fixed-price swap oil contracts and costless collar natural gas contracts. A fixed-price swap contract between the Company and a counterparty specifies a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume. A costless collar contract between the Company and the counterparty specifies a floor and a ceiling commodity price over a specified period for a contracted volume. The Company has not designated any of its contracts as fair value or cash flow hedges. Accordingly, the changes in fair value of the contracts are included in the consolidated statement of operations in the period of the change. All derivative gains and losses from the Company's derivative contracts have been recognized in revenue in the Company's accompanying consolidated statement of operations. Derivative instruments that have not yet been settled in cash are reflected as either derivative assets or liabilities in the Company's accompanying consolidated balance sheets as of December 31, 2020 and 2019.

The Company's oil fixed price swap transactions are settled based upon the average daily prices for the calendar month of the contract period and its natural gas costless collar contracts are settled based upon the last day settlement of the first nearby month futures contract of the contract period. Settlement for oil derivative contracts occurs in the succeeding month and natural gas derivative contracts are settled in the production month.

The Company's derivative contracts expose it to credit risk in the event of nonperformance by counterparties that may adversely impact the fair value of the Company's commodity derivative assets. While the Company does not require contract counterparties to post collateral, the Company does evaluate the credit standing on each counterparty as deemed appropriate. The evaluation includes reviewing a counterparty's credit rating and latest financial information. As of December 31, 2020, the Company had one counterparty, which is rated Aa3 or better by Moody's and is a lender under the Credit Facility. The Company did not enter into any derivative contracts during the year ended December 31, 2019.

The Company utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX, ICE or WTI published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX or ICE published market prices may be considered Level 1 if they are settled through a NYMEX or ICE clearing broker account with daily margining. Over-the-counter derivatives with NYMEX, ICE or WTI based prices are considered Level 2 due to the impact of counterparty credit risk. The Company's derivatives are classified within Level 2.

The table below summarizes the fair values and classifications of the Company's derivative instruments as of December 31, 2020 (in thousands):

		As of December 31, 2020		
Classification	**Balance Sheet Location**	**Gross Fair Value**	**Effect of Netting**	**Net Carrying Value**
Assets:				
Current asset	Other current assets	$ 342	$ (342)	$ -
Long-term asset	Other assets	-	-	-
Total assets		$ 342	$ (342)	$ -
Liabilities:				
Current liability	Other current liabilities	$ 1,286	$ (342)	$ 944
Long-term liability	Other non-current liabilities	-	-	-
Total liabilities		$ 1,286	$ (342)	$ 944

Changes in the fair values of the Company's derivative instruments are presented on a net basis in the accompanying consolidated statements of operations and consolidated statements of cash flows and consist of the following for the periods presented (in thousands):

	Year Ended December 31,		
	2020	**2019**	**2018**
Unrealized gain (loss) of open non-hedge derivative instruments	$ (944)	$ -	$ (1,151)
Realized gain (loss) on settlement of non-hedge derivative instruments	(256)	-	(305)
Gain (loss) on commodity derivative instruments	$ (1,200)	$ -	$ (1,456)

The Company had the following open derivative contracts for oil as of December 31, 2020:

Period and Type of Contract	Volume (Bbl)	Weighted Average Price (Per Bbl)	Range (Per Bbl) Low	High
Oil Swap Contracts:				
2021				
First Quarter	98,000	$ 40.40	$ 40.40	$ 40.40

The Company had the following open derivative contracts for natural gas as of December 31, 2020:

Period and Type of Contract	Volume (MMBtu)	Weighted Average Floor Price (Per MMBtu)	Weighted Average Ceiling Price (Per MMBtu)
Natural Gas Collar Contracts:			
2021			
First Quarter	481,000	$ 3.15	$ 3.55

Note 7—Oil and Natural Gas Interests

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

	As of December 31, 2020	December 31, 2019
Oil and natural gas interests:		
Subject to depletion	$ 319,487	$ 311,954
Not subject to depletion	32,463	37,580
Gross oil and natural gas interests	351,950	349,534
Accumulated depletion and impairment	(144,445)	(130,342)
Oil and natural gas interests, net	$ 207,505	$ 219,192

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, 2020, 2019 and 2018, the Company has recorded approximately $0 million, $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 8—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 provided for a maximum credit amount of $500.0 million and a borrowing base based on its oil and natural gas reserves and other factors (currently $70 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, 2020, the Company had borrowings of $39.8 million under the Credit Facility at an interest rate of 2.65% and $30.2 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 $1.8 million as of December 31, 2020.

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, 2020, the Company was in compliance with such covenants.

Note 9—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"). 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 Warrant 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 have been no additional changes to the exercise price since then. 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.

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.

The Company accounts for the Public and Private Placement Warrants (the "Warrants") in accordance with ASC 815. ASC 815 provides guidance for determining whether an equity-linked financial instrument (or embedded feature) is indexed to an entity's own stock. This applies to any freestanding financial instrument or embedded feature that has all the characteristics of a derivative under ASC 815, including any freestanding financial instrument that is potentially settled in an entity's own stock.

Due to certain circumstances that could require the Company to settle the Warrants in cash, the Warrants have been classified as derivative liabilities, as opposed to an equity contract. Therefore, the Warrants were recorded at fair value upon issuance and remeasured at each reporting period with the change in fair value recorded in the statement of operations. As of December 31, 2020 and 2019, there were 13,749,998 and 13,749,999, respectively, Public Warrants outstanding. As of December 31, 2020 and 2019, there were 7,500,000 Private Placement Warrants outstanding for each period. The fair value of the Public Warrants was determined using the readily observable publicly traded price (Level 1) as of the end of each reporting period and the Private Placement Warrants were estimated utilizing a binomial lattice model using the following range of significant unobservable inputs (Level 3) for the respective periods:

	2020	2019
Stock price	\$2.15 - \$3.20	\$5.75 - \$8.84
Volatility	60.1% - 71.9%	36.8% - 44.4%
Risk-free rate	0.16% - 0.31%	1.55% - 2.21%
Dividend yield	8.17% - 9.00%	7.58% - 10.30%
Term	2.65 - 3.40 years	3.65 - 4.40 years

The following is a reconciliation of the beginning and ending balance for the liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the years ended December 31, 2020, 2019 and 2018 (in thousands):

	Level 3 Warrant Liability
Fair value of warrant liability at August 23, 2018, time of Transactions	$ 42,500
Increase (decrease) in fair value	(27,800)
Fair value of warrant liability at December 31, 2018	$ 14,700
Increase (decrease) in fair value	(6,069)
Fair value of warrant liability at December 31, 2019	$ 8,631
Increase (decrease) in fair value	(5,128)
Fair value of warrant liability at December 31, 2020	$ 3,503

Note 10—Shareholders' 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, 2020.

	Class A Common Stock	Class C Common Stock	Warrants
Beginning Balance at December 31, 2019	45,963,716	40,000,000	21,249,999
Restricted stock grant vesting	143,466	-	-
Warrants exercised	1	-	(1)
Shares outstanding at December 31, 2020	46,107,183	40,000,000	21,249,998

Preferred stock - At December 31, 2020, 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, 2020, there were 46,107,183 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, 2020, 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.

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 54% 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, 2020, 2019 and 2018, $10.2 million, $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, 2020	$ 0.0750	$ 3,458	March 8, 2021	February 25, 2021
September 30, 2020	$ 0.0650	$ 2,997	December 8, 2020	November 24, 2020
June 30, 2020	$ 0.0300	$ 1,383	September 8, 2020	August 25, 2020
March 31, 2020	$ 0.0250	$ 1,150	June 8, 2020	May 25, 2020
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.

Note 11—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.

We utilized a lattice model pricing model to measure the fair value of the PSUs. The derived service period equals the median time to achieve the hurdle in all simulations where the hurdle was achieved. Volatility assumptions are based on the average historical volatility of Falcon stock over the derived service period of the PSU. The risk-free interest rate is based on the U.S. Treasury rate in effect at the time of the grant over the derived service period of the PSU. The dividend yield is based on an annual dividend yield, taking in account historical dividends, over the derived service period of the PSU. The Company used the following weighted average assumptions to estimate the grant date fair value of the PSUs granted during the year ended December 31, 2020 and 2019:

	2020		2019	
Stock price	$	2.24	$	9.05
Volatility		53.4%		42.3%
Risk-free rate		0.60%		2.42%
Dividend yield		9.10%		8.84%
Derived service period		3.00 years		2.35 - 4.00 years

The following table summarizes the activity in our unvested RSAs and PSUs for the years ended December 31, 2020 and 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
Granted	337,744	$	2.48	751,286	$	0.64
Vested	(143,466)	$	7.31	-	$	-
Forfeited	(1,958)	$	6.00	-	$	-
Unvested at December 31, 2020	476,237	$	4.36	2,164,620	$	2.48

For the years ended December 31, 2020 and 2019, the Company incurred $3.5 million and $2.5 million, respectively, 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 before 2019 and therefore the Company did not incur any related expenses during any years prior to 2019. The unamortized estimated fair value of unvested RSAs and PSUs was $3.2 million at December 31, 2020. These costs are expected to be recognized as expense over a weighted average period of 1.3 years. In addition, for the years ended December 31, 2020 and 2019, the Company paid $0.1 million and $0.2 million, respectively, of DERs to RSA holders.

Note 12—Earnings Per Share

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,		
	2020	2019	2018
Numerator:			
Net income attributable to common stockholders - basic	$ 7,700	$ 20,419	$ 36,966
Plus: Net income attributable to non-controlling interests, net of taxes	2,236	12,936	8,487
Less: Earnings allocated to participating securities	(64)	(115)	-
Net income attributable to common stockholders - diluted	$ 9,872	$ 33,240	$ 45,453
Denominator:			
Weighted average shares outstanding - basic	46,031	45,893	45,855
Effect of dilutive securities	40,000	40,000	40,000
Weighted average shares outstanding - diluted	86,031	85,893	85,855
Net income per common share - basic	$ 0.17	$ 0.44	$ 0.81
Net income per common share - diluted	$ 0.11	$ 0.39	$ 0.53

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,		
	2020	2019	2018
Warrants	21,250	21,250	21,250

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, 2020.

Note 13—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, 2020, 2019, and 2018, the Company recorded an income tax expense of $0.6 million, $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, 2020, and 2019, the Company had $55.8 million and $56.4 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.

As of December 31, 2020, and 2019, the Company had net operating loss carryforwards for federal income tax purposes of $9.7 million and $0 million, respectively, that, subject to limitation, may be available in future tax years to offset taxable income. The federal net operating loss carryforwards do not expire but are subject to certain income limitations in future tax years. In the event that the Company experiences an ownership change within the meaning of Section 382 of the Internal Revenue Code, our ability to utilize net operating losses, tax credits, and other tax attributes may be limited.

At December 31, 2020 and 2019, the Company had recorded a prepayment of income taxes of $0 million and $0.5 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, 2020. 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, 2020, 2019, and 2018 are as follows:

	For the Year Ended December 31,		
	2020	2019	2018
		(in thousands)	
Current income tax provision:			
Federal	$ 10	$ 1,459	$ 995
State	-	38	12
Total current income tax provision	10	1,497	1,007
Deferred income tax provision:			
Federal	574	2,399	2,264
State	5	22	21
Total deferred income tax provision	579	2,421	2,285
Total provision for income taxes	$ 589	$ 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,		
	2020	2019	2018
		(in thousands)	
Income tax expense at the federal statutory tax rate (21%)	$ 2,318	$ 8,589	$ 27,313
Impact of net income attributable to the non-controlling interests	(577)	(3,478)	(2,306)
State taxes, net of federal benefit	4	47	-
Impact of net income attributable to pre-business combination period	-	-	(16,576)
Impact of pre-business combination tax adjustment	-	-	824
Warrant liability adjustment	(1,077)	(1,274)	(5,838)
Other, net	(79)	34	(125)
Provision for (benefit from) income taxes	$ 589	$ 3,918	$ 3,292

The components of the Company's deferred tax assets and liabilities as of December 31, 2020 and 2019 are as follows:

	As of December 31,	
	2020	2019
	(in thousands)	
Deferred tax assets:		
Difference in carrying value and tax basis in oil and gas assets	$ 52,790	$ 56,057
Net operating loss	2,032	-
Share-based compensation	1,052	394
Total deferred tax assets	55,874	56,451
Valuation allowance	-	-
Net deferred tax assets	55,874	56,451
Deferred tax liabilities:		
Prepaid Expenses	101	99
Net deferred tax assets	$ 55,773	$ 56,352

Note 14—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.

Hepco Capital Management, LLC

Hepco Capital Management, LLC ("Hepco Capital"), which Company officer Jeffrey Brotman is also a director and officer 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, 2020, 2019, and 2018, the Company received $0.3 million, $0.3 million, and less than $0.1 million, respectively.

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 OpCo Common Units, 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, 2020, 2019, and 2018, the Company received $1.1 million, $0.6 million and less than $0.1 million, respectively, under this agreement.

Note 15—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:

	For the Year Ended December 31,		
	2020	**2019**	**2018**
Conoco Phillips	42%	33%	39%
EOG	20%	29%	22%
Devon	16%	18%	16%
Total	78%	80%	77%

Note 16—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.

Note 17—Subsequent Events

Cash Dividends

In February 2021, the Company declared a quarterly cash dividend of $0.075 per share of Class A Common Stock totaling approximately $3.5 million for all shares of Class A Common Stock outstanding. The dividend is for the period from October 1, 2020 through December 31, 2020. The dividend was paid on March 8, 2021 to all Class A shareholders of record on February 25, 2021.

OpCo Distribution

In March 2021, OpCo made distributions totaling $6.5 million to its unitholders. Of the $6.5 million distributed by OpCo, the Company received $3.5 million.

Note 18 – Quarterly Financial Data (Unaudited)

Subsequent to the issuance of the Company's consolidated financial statements as of December 31, 2020 and 2019 and for the years ended December 31, 2020, 2019 and 2018, the SEC Division of Corporation of Finance released Staff Statement on Accounting and Reporting Considerations for Warrants Issued by Special Purpose Acquisition Companies ("SPACs") (the "Statement") on April 12, 2021. Upon review and analysis of the Statement, management determined that the Company's Public Warrants and Private Placement Warrants issued in connection with the closing of the Osprey initial public offering in July 2017 (see Notes 1 and 9) do not meet the scope exception from derivative accounting prescribed by ASC 815-40. Accordingly, the Warrants should have been recognized by the Company at fair value as of August 23, 2018, the Closing Date, and classified as a liability, rather than equity in the Company's previously reported consolidated balance sheet. Thereafter, the change in fair value of the outstanding Warrants should have been recognized as a derivative gain (loss) each reporting period in the Company's consolidated statement of operations. The fair value of the Warrants that should have been recorded as of the Closing Date on August 23, 2018 was $42,500 thousand. The change in fair value amounted to $5,678, $207, $971, and $(1,728) thousand for the quarters ended March 31, June 30, September 30, and December 31, 2020, respectively. The change in fair value amounted to $(4,887), $(1,350), $13,516, and $(1,210) thousand for the quarters ended March 31, June 30, September 30, and December 31, 2019, respectively. Management concluded the effect of this error on the Company's previously reported consolidated financial statements is material and, as such, the accompanying unaudited quarterly financial data for each of the quarters in the years ended December 31, 2020 and 2019, have been restated from the amounts previously reported to give effect to the correction of this error.

The following tables reflect the impact of the Restatement of the Company's previously reported unaudited quarterly financial data:

(in thousands, except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2020:				
Revenues	$ 13,600	$ 6,115	$ 9,669	$ 9,497
Operating income (loss)	$ 5,602	$ (1,104)	$ 2,014	$ 1,469
Net income (loss) attributable to common shareholders	$ 7,883	$ (368)	$ 1,560	$ (1,375)
Net income (loss) per share:				
Common shares - basic	$ 0.17	$ (0.01)	$ 0.03	$ (0.03)
Common shares - diluted	$ 0.11	$ (0.01)	$ 0.02	$ (0.03)
Weighted average number of shares outstanding:				
Common shares - basic	45,967	46,001	46,055	46,099
Common shares - diluted	85,967	46,001	86,055	46,099

(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	$ 495	$ 2,406	$ 16,400	$ 1,118
Net income per share:				
Common shares - basic	$ 0.01	$ 0.05	$ 0.36	$ 0.02
Common shares - diluted	$ 0.01	$ 0.05	$ 0.22	$ 0.02
Weighted average number of shares outstanding:				
Common shares - basic	45,856	45,858	45,899	45,956
Common shares - diluted	45,856	45,858	85,899	45,956

Note 19 – 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, 2020	As of December 31, 2019
	(in thousands)	
Proved royalty interest	$ 319,487	$ 311,954
Unproved royalty interests	32,463	37,580
Accumulated amortization	(144,445)	(130,342)
Net royalty interests in oil and natural gas properties	$ 207,505	$ 219,192

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,		
	2020	2019	2018
	(in thousands)		
Acquisition costs:			
Proved properties	$ 1,066	$ 4,011	$ 207
Unproved properties	1,351	18,750	1,008
Total	$ 2,417	$ 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,		
	2020	2019	2018
	(in thousands)		
Royalty income	$ 40,081	$ 68,463	$ 98,655
Production and ad valorem taxes	(2,807)	(4,262)	(5,143)
Marketing and transportation	(1,993)	(2,396)	(2,368)
Depletion	(14,103)	(12,737)	(16,962)
Income tax expense	(589)	(3,918)	(3,292)
Results of operations from oil, natural gas and natural gas liquids	$ 20,589	$ 45,150	$ 70,890

Oil and Natural Gas Reserves

Proved oil and gas reserve estimates as of December 31, 2020, 2019 and 2018 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, 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
Purchase of reserves in place	62	62	-	72
Extensions and discoveries	34	797	12	179
Revisions of previous estimates	(2,114)	4,935	(298)	(1,590)
Production	(836)	(3,528)	(247)	(1,671)
As of December 31, 2020	9,742	48,536	2,186	20,017
Proved Developed Reserves				
December 31, 2018	3,857	18,700	1,293	8,267
December 31, 2019	3,900	18,016	1,230	8,133
December 31, 2020	3,291	19,755	1,164	7,747
Proved Undeveloped Reserves:				
December 31, 2018	11,355	37,485	1,870	19,473
December 31, 2019	8,696	28,254	1,489	14,894
December 31, 2020	6,451	28,781	1,022	12,270

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, 2020, the Company's negative revisions of previous estimates of 1,590 MBOE resulted primarily from reducing the existing PUD locations by 269 wells due to a change in development timing and lower commodity prices. The purchase of reserves in place of 72 MBOE were due to multiple acquisitions located within the Eagle Ford Shale.

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.

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, 2020, 2019 and 2018:

	December 31,		
	2020	2019	2018
	(in thousands)		
Future cash inflows	$ 476,315	$ 882,076	$ 1,265,153
Future production costs	(41,770)	(70,956)	(98,672)
Future income tax expense	(6,431)	(48,040)	(87,803)
Future net cash flows	428,114	763,080	1,078,678
10% discount to reflect timing of cash flows	(176,302)	(304,730)	(469,808)
Standardized measure of discounted cash flows	$ 251,812	$ 458,350	$ 608,870

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,		
	2020	2019	2018
	Unweighted Arithmetic Average First-Day-of-the-Month Prices		
Oil (per Bbl)	$ 39.57	$ 55.69	$ 65.56
Natural gas (per Mcf)	$ 1.99	$ 2.58	$ 3.10
Natural gas liquids (per Bbl)	$ 12.27	$ 13.37	$ 25.57

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

	December 31,		
	2020	2019	2018
	(in thousands)		
Standardized measure of discounted future net cash flows at the beginning of the period	$ 458,350	$ 608,870	$ 595,579
Purchase of minerals in place	2,134	1,256	1,092
Sales of oil and natural gas, net of production costs	(35,281)	(59,949)	(91,180)
Extensions and discoveries	1,462	9,711	-
Net changes in prices and production costs	(148,892)	(91,386)	165,659
Revisions of previous quantity estimates	(72,896)	(92,479)	41,728
Divestiture of reserves	-	-	(73,755)
Net changes in income taxes	25,419	20,613	(49,758)
Accretion of discount	44,279	65,863	59,558
Net changes in timing of production and other	(22,763)	(4,149)	(40,053)
Standardized measure of discounted future net cash flows at the end of the period	$ 251,812	$ 458,350	$ 608,870

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Our Directors and Executive Officers

Principal Officers

Daniel C. Herz
Chief Executive Officer, President and Director

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

Non-Employee Directors

Claire Harvey, Chairman
Chief Executive Officer of Gryphon Oil and Gas, LLC

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

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

Erik C. Belz
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.

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Continental Stock Transfer & Trust
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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, 2020 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 2021 Annual Meeting of Stockholders scheduled to be held on May 27, 2021 at 11:00 a.m.

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