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

Form 10-K

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

For the fiscal year ended December 31, 2021

OR

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

Commission file number: 001-35371

Civitas Resources, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**61-1630631**
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification number)
555 17th Street, Suite 3700	
Denver, Colorado	**80202**
(Address of principal executive offices)	(Zip Code)

(303) 293-9100

(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

(Title of Class)	**(Trading Symbol)**	**(Name of Exchange)**
Common Stock, par value $0.01 per share	CIVI	New York Stock Exchange

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 control 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 ☒

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

The aggregate market value of the registrant's voting and non-voting common equity held by non-affiliates on June 30, 2021, based upon the closing price of $47.07 of the registrant's common stock as reported on the New York Stock Exchange, was approximately $1.2 billion. Excludes approximately 5.5 million shares of the registrant's common stock held by executive officers, directors, and stockholders that the registrant has concluded, solely for the purpose of the foregoing calculation, were affiliates of the registrant.

Number of shares of registrant's common stock outstanding as of March 4, 2022: 84,937,154

Documents Incorporated By Reference:

Portions of the registrant's definitive proxy statement, will be filed with the Securities and Exchange Commission within 120 days of December 31, 2021, as incorporated by reference into Part III of this report for the year ended December 31, 2021.

CIVITAS RESOURCES, INC.
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2021

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Information Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains various statements, including those that express belief, expectation or intention, as well as those that are not statements of historic fact, that are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended (the “Exchange Act”). When used in this Annual Report on Form 10-K, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may,” “continue,” “predict,” “potential,” “project,” “plan,” “will,” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements include statements related to, among other things:

- the Company’s business strategies;
- reserves estimates;
- estimated sales volumes;
- the amount and allocation of forecasted capital expenditures and plans for funding capital expenditures and operating expenses;
- our ability to modify future capital expenditures;
- anticipated costs;
- compliance with debt covenants;
- our ability to fund and satisfy obligations related to ongoing operations;
- compliance with government regulations, including environmental, health, and safety regulations and liabilities thereunder;
- the adequacy of gathering systems and continuous improvement of such gathering systems;
- the impact from the lack of available gathering systems and processing facilities in certain areas;
- the impact of any pandemic or other public health epidemic, including the ongoing COVID-19 pandemic;
- oil, natural gas, and natural gas liquid prices and factors affecting the volatility of such prices;
- the impact of lower commodity prices;
- sufficiency of impairments;
- the ability to use derivative instruments to manage commodity price risk and ability to use such instruments in the future;
- our drilling inventory and drilling intentions;
- the impact of potentially disruptive technologies;
- our estimated revenue gains and losses;
- the timing and success of specific projects;
- our implementation of standard and long reach laterals;
- our intention to continue to optimize enhanced completion techniques and well design changes;
- stated working interest percentages;
- our management and technical team;
- outcomes and effects of litigation, claims, and disputes;
- primary sources of future production growth;
- our ability to replace oil and natural gas reserves;
- our ability to convert proved undeveloped reserves to producing properties within five years of their initial proved booking;

- our ability to pay future cash dividends on our common stock;
- the impact of the loss a single customer or any purchaser of our products;
- the timing and ability to meet certain volume commitments related to purchase and transportation agreements;
- the impact of customary royalty interests, overriding royalty interests, obligations incident to operating agreements, liens for current taxes, and other industry-related constraints;
- our anticipated financial position, including our cash flow and liquidity;
- the adequacy of our insurance;
- the results, effects, benefits, and synergies of the Extraction Merger and the Crestone Peak Merger, future opportunities for the combined companies, other plans and expectations with respect to the mergers, and the anticipated impact of the mergers on the combined company's results of operations, financial position, growth opportunities, and competitive position; and
- other statements concerning our anticipated operations, economic performance, and financial condition.

We have based these forward-looking statements on certain assumptions and analyses we have made in light of our experience and our perception of historical trends, current conditions, and expected future developments as well as other factors we believe are appropriate under the circumstances. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Many such factors will be important in determining actual future results. The actual results or developments anticipated by these forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control, and may not be realized or, even if substantially realized, may not have the expected consequences. Actual results could differ materially from those expressed or implied in the forward-looking statements.

Factors that could cause actual results to differ materially include, but are not limited to, the following:

- the risk factors discussed in Part I, Item 1A of this Annual Report on Form 10-K;
- declines or volatility in the prices we receive for our oil, natural gas, and natural gas liquids;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business;
- the effects of disruption of our operations or excess supply of oil and natural gas due to world health events, including the COVID-19 pandemic, and the actions by certain oil and natural gas producing countries;
- the scope, duration and severity of the COVID-19 pandemic, including any recurrence, as well as the timing and extent of the economic recovery following the pandemic;
- ability of our customers to meet their obligations to us;
- our access to capital;
- our ability to generate sufficient cash flow from operations, borrowings, or other sources to enable us to fully develop our undeveloped acreage positions;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future sales volume rates and associated costs;
- uncertainties associated with estimates of proved oil and gas reserves;
- the possibility that the industry may be subject to future local, state, and federal regulatory or legislative actions (including additional taxes and changes in environmental regulation);
- environmental risks;
- seasonal weather conditions;
- lease stipulations;
- drilling and operating risks, including the risks associated with the employment of horizontal drilling and completion techniques;
- our ability to acquire adequate supplies of water for drilling and completion operations;
- availability of oilfield equipment, services, and personnel;
- exploration and development risks;

- operational interruption of centralized oil and natural gas processing facilities;
- competition in the oil and natural gas industry;
- management's ability to execute our plans to meet our goals;
- our ability to attract and retain key members of our senior management and key technical employees;
- our ability to maintain effective internal controls;
- access to adequate gathering systems and pipeline take-away capacity;
- our ability to secure adequate processing capacity for natural gas we produce, to secure adequate transportation for oil, natural gas, and natural gas liquids we produce, and to sell the oil, natural gas, and natural gas liquids at market prices;
- costs and other risks associated with perfecting title for mineral rights in some of our properties;
- political conditions in or affecting other producing countries, including conflicts in or relating to the Middle East, South America, and Russia (including the current events involving Russia and Ukraine), and other sustained military campaigns or acts of terrorism or sabotage; and
- other economic, competitive, governmental, legislative, regulatory, geopolitical, and technological factors that may negatively impact our businesses, operations, or pricing.

All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. We disclaim any obligation to update or revise these statements unless required by law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions, and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report on Form 10-K are reasonable, we can give no assurance that these plans, intentions, or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under Item 1A. *Risk Factors* and Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations* and elsewhere in this Annual Report on Form 10-K. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

GLOSSARY OF OIL AND NATURAL GAS TERMS

We have included below the definitions for certain terms used in this Annual Report on Form 10-K:

"3-D seismic data." Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic data typically provide a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic data.

"Analogous reservoir." Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

"Asset Sale." Any direct or indirect sale, lease (including by means of production payments and reserve sales and a sale and lease-back transaction), transfer, issuance, or other disposition, or a series of related sales, leases, transfers, issuances, or dispositions that are part of a common plan, of (a) shares of capital stock of a subsidiary, (b) all or substantially all of the assets of any division or line of business of the Company or any subsidiary, or (c) any other assets of the Company or any subsidiary outside of the ordinary course of business.

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

"Bcf." One billion cubic feet of natural gas.

"Boe." One stock tank barrel of oil equivalent, calculated by converting natural gas and natural gas liquids volumes to equivalent oil barrels at a ratio of six Mcf to one Bbl of oil.

"British thermal unit" or *"Btu."* The heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

"Basin." A large natural depression on the earth's surface in which sediments generally deposited via water accumulate.

"Completion." The process of stimulating a drilled well followed by the installation of permanent equipment to allow for the production of crude oil and/or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"Condensate." A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

"Developed acres." The number of acres that are allocated or assignable to productive wells or wells capable of production.

"Development costs." Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves; (ii) drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly; (iii) acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (iv) provide vapor recovery systems.

"Development well." A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

"Differential." The difference between a benchmark price of oil and natural gas, such as the NYMEX crude oil spot, and the wellhead price received.

"Deterministic method." The method of estimating reserves or resources using a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation.

"Dry hole." Exploratory or development well that does not produce oil or gas in commercial quantities.

"Economically producible." The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the cash costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities.

"Estimated ultimate recovery (EUR)." Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

"Exploratory well." A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.

"Extension well." A well drilled to extend the limits of a known reservoir.

"Field." An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

"Finding and development costs." Calculated by dividing the amount of total capital expenditures for oil and natural gas activities, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, acquisitions, and revisions of previous estimates less sales of reserves, during the same period.

"Formation." A layer of rock which has distinct characteristics that differ from nearby rock.

"GAAP." Generally accepted accounting principles in the United States.

"Gross Wells." The total wells in which an entity owns a working interest.

"HH." Henry Hub index.

"Horizontal drilling." A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

''Hydraulic fracturing." The process of injecting water, proppant, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production into the wellbore.

"Infill drilling." The addition of wells in a field that decreases average well spacing.

"LIBOR." London interbank offered rate.

"LOE." Lease operating expense.

"MBbl." One thousand barrels of oil or other liquid hydrocarbons.

"MBoe." One thousand Boe.

"Mcf." One thousand cubic feet.

"MMBoe." One million Boe.

"MMBtu." One million British Thermal Units.

"MMcf." One million cubic feet.

"Net acres." The percentage of total acres an owner has out of a particular number of acres or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"Net production." Production that is owned by the registrant and produced to its interest, less royalties and production due others.

"Net revenue interest." Economic interest remaining after deducting all royalty interests, overriding royalty interests, and other burdens from the working interest ownership.

"Net well." Deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interest owned in gross wells expressed as whole numbers and fractions of whole numbers.

"NGL." Natural gas liquid.

"NYMEX." The New York Mercantile Exchange.

"Oil and gas producing activities." Defined as (i) the search for crude oil, including condensate and natural gas liquids, or natural gas in their natural states and original locations; (ii) the acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties; (iii) the construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as lifting the oil and gas to the surface and gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and (iv) extraction of salable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coal beds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

"OPIS." Oil Price Information Service, a common industry benchmark for NGL pricing.

"PDNP." Proved developed non-producing reserves.

"PDP." Proved developed producing reserves.

"Percentage-of-proceeds." A processing contract where the processor receives a percentage of the sold outlet stream, dry gas, NGLs, or a combination from the mineral owner in exchange for providing the processing services.

"Play." A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and gas reserves.

"Plugging and abandonment." The sealing off of all gas and liquids in the strata penetrated by a well so that the gas and liquids from one stratum will not escape into another stratum or to the surface.

"Pooling." Pooling, either contractually or statutorily through regulatory actions, allows an operator to combine multiple leased tracts to create a governmental spacing unit for one or more productive formations. Pooling is also known as unitization or communitization. Ownership interests are calculated within the pooling/spacing unit according to the net acreage contributed by each tract within the pooling/spacing unit.

"Possible reserves." Those additional reserves that are less certain to be recovered than probable reserves.

"Probable reserves." Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

"Production costs." Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are (a) costs of labor to operate the wells and related equipment and facilities; (b) repairs and maintenance; (c) materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities; (d) property taxes and insurance applicable to proved properties and wells and related equipment and facilities; and (e) severance taxes. Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development, or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the costs of oil and gas produced along with production (lifting) costs identified above.

"Productive well." An exploratory, development, or extension well that is not a dry well.

"Proppant." Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

"Proved developed reserves." Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

"Proved reserves." Those quantities of oil and 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. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

   (a) The area identified by drilling and limited by fluid contacts, if any, and

   (b) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher potions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(a) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and

(b) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

"Proved undeveloped reserves" or *"PUD."* Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

"PV-10." A non-GAAP financial measure that represents inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows using the twelve-month unweighted arithmetic average of the first-day-of-the-month commodity prices (after adjustment for differentials in location and quality) for each of the preceding twelve months. Please refer to footnote 2 of the Proved Reserves table in Item 1 of this Annual Report on Form 10-K for additional discussion.

"Reasonable certainty." If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical) engineering, and economic data are made to estimated ultimate recovery ("EUR") with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

"*Reclamation."* The process to restore the land and other resources to their original state prior to the effects of oil and gas development.

"Recompletion." The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"Reserves." Estimated remaining quantities of oil and 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 gas or related substances to market, and all permits and financing required to implement the project.

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

"Royalty interest." An interest in an oil and natural gas property entitling the owner to a share of oil, natural gas, or NGLs produced and sold unencumbered by expenses of drilling, completing, and operating of the well.

"Sales volumes." All volumes for which a reporting entity is entitled to proceeds, including production, net to the reporting entity's interest and third party production obtained from percentage-of-proceeds contracts and sold by the reporting entity.

"Service well." A service well is drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

"Spacing." Spacing as it relates to a spacing unit is defined by the governing authority having jurisdiction to designate the size in acreage of a productive reservoir along with the appropriate well density for the designated spacing unit size. Typical spacing for conventional wells is 40 acres for oil wells and 640 acres for gas wells. Typical spacing for unconventional wells is either 640 acres or 1,280 acres for both oil and gas.

"Standard reach lateral equivalent well." Equates to a ratio of one well to one well for a standard reach lateral well, one and half wells to one well for a medium reach lateral well, and two wells to one well for an extended reach lateral well. Standard reach laterals typically include lengths of up to one mile, medium reach laterals of up to one and a half miles, and extended reach laterals of up to two miles.

"Undeveloped acreage." Those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves.

"Undeveloped reserves." Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Also referred to as "undeveloped oil and gas reserves."

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

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

"WTI." West Texas Intermediate index.

PART I

Item 1. *Business*

When we use the terms "Civitas," the "Company," "we," "us," or "our," we are referring to Civitas Resources, Inc. and its consolidated subsidiaries unless the context otherwise requires. We have included certain technical terms important to an understanding of our business under *Glossary of Oil and Natural Gas Term* above. Throughout this document, we make statements that may be classified as "forward-looking." Please refer to the *Information Regarding Forward-Looking Statements* section above for an explanation of these types of statements.

Overview

Civitas is an independent Denver-based exploration and production company focused on the acquisition, development, and production of oil and associated liquids-rich natural gas in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin (the "DJ Basin") of Colorado. At year-end, we had approximately 481,500 net acres of large, contiguous acreage blocks in some of the most productive areas of the DJ Basin. We believe our acreage in the DJ Basin has been significantly delineated by our own drilling success and by the success of offset operators, providing confidence that our inventory is repeatable and will continue to generate economic returns.

As of December 31, 2021, we operated a total of 2,838 gross producing wells, of which 2,330 were horizontal. Our working and net revenue interest for all operated wells averaged approximately 78% and 64%, respectively. The Wattenberg Field has a low cost structure, mature infrastructure, strong production efficiencies, multiple producing horizons, multiple service providers, established reserves, and prospective drilling opportunities, which helps facilitate predictable production and reserve growth. In 2022, we expect to run an average of 3.5 operated rigs and 3 operated crews that will drill 190 to 210 and complete 165 to 175 gross operated wells. We continually monitor the commodity price and regulatory environment and retain the operational and financial flexibility to adjust our drilling and completion plans in response to such conditions.

We consider our liquidity, low leverage, and minimal volume commitments to be a core strength and strategic advantage that we are focused on maintaining. Civitas is committed to maintaining low leverage and high financial flexibility. Additionally, our strong liquidity position of over $1.0 billion as of December 31, 2021 is expected to deliver further financial flexibility to execute on our long-term strategy.

Civitas is focused on exceptional performance in managing Environmental, Social, and Governance ("ESG") issues, with a goal of mitigating risks while benefiting our stakeholders and the communities where we operate. Utilizing an aggressive operational emissions-reduction program coupled with multi-year investment in certified emissions credits to offset residual emissions, we believe Civitas is Colorado's first carbon neutral operator on both a Scope 1 and Scope 2 basis, meaning that Civitas is at net-zero balance between emitting and absorbing carbon from the atmosphere. Any carbon dioxide released into the atmosphere as a result of Civitas operations has been balanced by an equivalent amount of carbon dioxide being removed. This is achieved via both internal reductions of greenhouse gas emissions and through the purchase of carbon offsets and renewable energy credits. Additional planned projects include electric vehicle fleet conversion, community solar development, and installation of electric vehicle charging stations, as well as an ongoing responsibly sourced gas partnership with Xcel Energy, and partnerships with the Payne Institute, which we believe will solidify Civitas as a responsible steward of the energy transition. Civitas' Board of Directors also has a dedicated ESG Committee that is responsible for overseeing and supporting the Company's commitment to environmental, health, and safety, social responsibility, sustainability, and other public policy matters relevant to the Company. The ESG Committee assists senior management in setting the Company's general strategy relating to ESG matters and in developing, implementing, and monitoring initiatives and policies based on that strategy.

Our Business Strategies

The Company's primary objective is to maximize shareholder returns by responsibly developing our oil and natural gas resources. Key aspects of our strategy include:

- *Multi-well pad development across our leasehold.* We believe horizontal development is the most efficient, environmentally responsible, and safest way to recover the hydrocarbons located within our leasehold. We continuously evaluate completion designs to increase well productivity and apply a multivariate regression analysis with the objective of optimizing economic returns. Petrophysical, geological, and geophysical analysis is used in conjunction with spacing evaluations and individualized well designs to increase value of each spacing unit.

- *Continuous safety improvement and strict adherence to health and safety regulations.* Our goal is to utilize industry best practices to meet or exceed regulatory requirements and consistently engage stakeholders in our development planning and operations. We strive to maintain a safe workplace for our employees and contractors at all times.

Specifically, during 2021, we maintained a meaningful safety track record as evidenced by a low total recordable incident rate of 0.17 for the year ended December 31, 2021.

- *Environmental stewardship.* We believe we are the first carbon neutral operator in Colorado on both a Scope 1 and Scope 2 basis. We constantly strive to control and reduce emissions and seek to comply with all applicable air quality and other environmental rules and regulations. We employ industry-leading best practices, including electric drilling rigs and pipeline gathering and takeaway as well as vapor recovery and leak detection equipment where feasible and appropriate. Additionally, we work closely with our service providers to help ensure they stay in compliance with environmental regulations when operating on our behalf.

- *Disciplined approach to acquisitions and divestitures and capital allocation.* Opportunities are evaluated primarily in the context of maintaining development flexibility, significant free cash flow, and a strong financial profile. We pursue value-accretive acquisitions and strive to maximize scale while minimizing financial and operational risk.

- *Prudent risk management.* The Company believes a healthy balance sheet, focus on cost control, and minimizing long-term commitments are critical to controlling risk. A low debt profile and judicious use of hedging practices help reduce cash flow volatility. We believe we have one of the lowest cost structures in the basin. Continually striving to be a cost-efficient operator and maintaining a flexible capital spending program enable us to respond to changing market conditions.

Significant Developments in 2021

2021 was a transformational year for Civitas. On April 1, 2021, Civitas completed its acquisition of HighPoint Resources Corporation, a Delaware corporation (“HighPoint”) pursuant to the terms of the related Agreement and Plan of Merger (the “HighPoint Merger”). On November 1, 2021, Civitas completed its merger with Extraction Oil & Gas, Inc., a Delaware corporation (“Extraction”), pursuant to the terms of the related Agreement and Plan of Merger (the “Extraction Merger”) and its acquisition of CPPIB Crestone Peak Resources America Inc., a Delaware corporation (“Crestone Peak”), pursuant to the terms of the related Agreement and Plan of Merger (the “Crestone Peak Merger”). These mergers positioned Civitas as the largest pure-play DJ Basin producer and created a combined business with peer-leading scale that allow us to maximize our unique competitive strengths and maintain low costs. Civitas’ 2022 budget includes LOE and recurring cash G&A costs per Boe that are more than 30% lower than that of the nine months ended September 30, 2021, highlighting the anticipated benefits of consolidation. The Company’s low-cost operating model, combined with its high-quality asset base and fortress balance sheet is expected to allow Civitas to deliver significant value to stakeholders.

Further, in May 2021, the Company announced that the Board of Directors (the “Board”) established an annual fixed cash dividend of $1.40 per share, to be declared and paid on a quarterly basis. Upon the closing of the Extraction and Crestone Peak mergers, the annual fixed cash dividend was increased to $1.85 per share. Finally, in March 2022, the Board approved the initiation of a quarterly variable cash dividend equal to 50% of free cash flow after the fixed cash dividend for the preceding twelve-month period and pro forma for all acquisition and divestiture activity, assuming pro forma compliance with certain leverage targets. The Company’s inaugural quarterly variable cash dividend has been declared at $0.75 per share and will be paid in combination with the fixed cash dividend on March 30, 2022 to shareholders of record on March 18, 2022. The total quarterly dividend of $1.2125 per share equates to a 10% annualized dividend yield based on the share price as of February 28, 2022, which we believe is one of the highest yields in the sector.

On the operations front, the Company continued its development in the DJ Basin while testing enhanced completion designs on large, efficient multi-well pads throughout the Company’s acreage position. Enhanced completion designs varied to ensure that thorough knowledge could be applied to future development programs. Fluid volumes and types, fluid rates, proppant volumes and types, stage spacing, perforation architecture, lateral spacing, and flowback techniques were the primary variables that were tested throughout the 2021 program. Along with extensive internal evaluation, the Company will also continue to monitor industry trends, public data, and information from non-operated wells to further define optimum completion techniques. We focused our efforts on completing drilled but uncompleted wells during the first nine months of 2021 and deployed an average of three rigs during the fourth quarter of 2021. The aforementioned mergers, along with the Company's drilling and completion activity in 2021, drove an increase to our sales volumes of approximately 364% when comparing the fourth quarters of 2021 and 2020.

During 2021, the Company incurred capital costs of $299.4 million that, along with the incremental production acquired through mergers, drove an increase in sales volumes to 56.0 MBoe per day. The capital invested during 2021 allowed the Company to drill 49 gross operated wells, complete 100 gross operated wells, and turn to sales 70 gross operated wells.

The Company's midstream assets provide reliable gathering, treating, and storage for the Company's operated production while reducing facility site footprints, leading to more cost-efficient operations and reduced emissions and surface disturbance per Boe produced. Additionally, this infrastructure helps ensure that the Company's production is not constrained by any single midstream service provider.

Rocky Mountain Infrastructure ("RMI"), together with adjacent gathering assets acquired from HighPoint, serves the Company's eastern acreage position with multiple interconnects to four different natural gas processors. Significant cost and operational synergies have been realized with the combination of RMI and HighPoint midstream assets. Additionally, in 2019, the Company installed a new oil gathering line to Riverside Terminal (on the Grand Mesa Pipeline), which resulted in a corresponding $1.25 to $1.50 per barrel reduction to our oil differentials for barrels transported on such gathering line. The Company completed an additional oil interconnect in September 2021, thus providing additional outlets that provide flow assurance and minimize differentials. The total value of reduced oil differentials during the years ended December 31, 2021 and 2020 was approximately $5.0 million and $6.2 million, respectively

As a result of the Crestone Peak Merger, the Company acquired a gas gathering system that serves the Company's southern acreage position and an oil gathering system that serves a portion of the Company's western acreage. The gas gathering system ensures reliable, low-pressure service at the wellhead. The capacity of this system is in the process of being expanded with the addition of another compressor station. The oil gathering system gathers, treats, and stores oil and water from multiple nearby producing pads and subsequently delivers each to downstream outlets.

The following table summarizes our estimated proved reserves as of December 31, 2021:

Estimated Proved Reserves	**Crude Oil (MBbls)**	**Natural Gas (MMcf)**	**Natural Gas Liquids (MBbls)**	**Total Proved (MBoe)**
Developed	104,078	748,762	88,967	317,839
Undeveloped	39,501	139,737	17,061	79,851
Total Proved	143,579	888,499	106,028	397,690

Total proved reserves as of December 31, 2021 increased by approximately 236% over the comparable period in 2020.

The following table summarizes our PV-10 reserve value, sales volumes, projected capital spend, and proved undeveloped drilling locations as of December 31, 2021:

Estimated Proved Reserves at December 31, 2021(1)			**Average Net Daily Sales Volumes for the Year Ended December 31, 2021**	**Projected Drilling & Completion 2022 Capital Expenditures**	**Gross Proved Undeveloped Drilling Locations as of December 31, 2021(3)**
Total Proved (MBoe)	**% Proved Developed**	**PV-10 ($ in MM)(2)**	**(Boe/d)**	**($ in millions)**	
397,690	80 %	$ 5,327.2	56,015	$ 825.0 - 950.0	234

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(1) Proved reserves and related future net revenue and PV-10 were calculated using prices equal to the twelve-month unweighted arithmetic average of the first-day-of-the-month commodity prices for each of the preceding twelve months, which were $66.56 per Bbl WTI and $3.60 per MMBtu HH. Adjustments were then made for location, grade, transportation, gravity, and Btu content, which resulted in a decrease of $4.96 per Bbl for crude oil and a decrease of $1.24 per MMBtu for natural gas assuming an average Btu factor of 1.1 MMBtu/Mcf.

(2) We believe that PV-10 provides useful and relevant information to investors as it is widely used by professional analysts and sophisticated investors when evaluating oil and gas companies (specifically, the relative monetary significance of our reserves). Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable in evaluating the Company and our reserves. PV-10 is not intended to represent the current market value of our estimated reserves. PV-10 differs from Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") because it does not include the effect of future income taxes. Please refer to the *Reconciliation of PV-10 to Standardized Measure* presented in the "Reserves" subsection of Item 1 below.

(3) The Company's gross proved undeveloped drilling locations as of December 31, 2021 have an average lateral length of 2 miles.

Our Operations

Our operations are located in the Rocky Mountain region, primarily in the Wattenberg Field of the DJ Basin of Colorado, and target the Niobrara and Codell formations. As of December 31, 2021, our total position consisted of approximately 769,900 gross (536,700 net) acres, and our estimated proved reserves were 397,690 MBoe and contributed 56.0 MBoe per day of sales volumes during 2021. We believe our position allows us to control the pace, costs, and completion techniques used in the development of our reserves.

As of December 31, 2021, we had interests in a total of 3,918 gross producing wells, of which 3,351 were horizontal and 508 were net revenue only interests. Our working and net revenue interest for all wells in which we had a working interest averaged approximately 67% and 54%, respectively. Our sales volumes for the fourth quarter of 2021 were 116.2 MBoe per day.

We drilled and participated in drilling 49 gross (43.0 net) wells in 2021 in the Wattenberg Field. As of December 31, 2021, we have an identified drilling inventory of approximately 234 gross (178.0 net) proved undeveloped drilling locations on our acreage.

Reserves

Estimated Proved Reserves

The summary data with respect to our estimated proved reserves presented below has been prepared in accordance with rules and regulations of the Securities and Exchange Commission (the “SEC”) applicable to companies involved in oil and natural gas producing activities. Our reserve estimates do not include probable or possible reserves. Our estimated proved reserves for the years ended December 31, 2021, 2020, and 2019 were determined using the preceding twelve month unweighted arithmetic average of the first-day-of-the-month prices. For a definition of proved reserves under the SEC rules, please see the *Glossary of Oil and Natural Gas Terms* included in the beginning of this report.

Reserve estimates are inherently imprecise and estimates for undeveloped properties are more imprecise than reserve estimates for producing oil and gas properties. Accordingly, all of these estimates are expected to change as new information becomes available. Neither prices nor costs have been escalated. The actual quantities and present values of our estimated proved reserves may vary from what we have estimated.

The table below sets forth information regarding our estimated proved reserves, nearly all of which is located in the Wattenberg Field in the Rocky Mountain region, as of December 31, 2021, 2020, and 2019. The proved reserve estimates were prepared by third-party independent reserve engineers Ryder Scott Company, LP. ("Ryder Scott") as of December 31, 2021 and 2020 and by Netherland, Sewell & Associates, Inc. ("NSAI") as of December 31, 2019. For more information regarding our independent reserve engineers, please see *Independent Reserve Engineers* below. The information in the following table is not intended to represent the current market value of our proved reserves nor does it give any effect to or reflect our commodity price derivatives or current commodity prices.

	As of December 31,		
	2021	**2020**	**2019**
Reserve Data[(1)]:			
Estimated proved reserves:			
Oil (MMBbls)	143.6	52.8	64.4
Natural gas (Bcf)	888.5	235.7	212.2
Natural gas liquids (MMBbls)	106.0	26.1	22.2
Total estimated proved reserves (MMBoe)[(2)]	397.7	118.2	121.9
Percent oil and liquids	63 %	67 %	71 %
Estimated proved developed reserves:			
Oil (MMBbls)	104.1	24.3	25.4
Natural gas (Bcf)	748.8	123.2	105.8
Natural gas liquids (MMBbls)	89.0	14.3	11.6
Total estimated proved developed reserves (MMBoe)[(2)]	317.8	59.2	54.6
Percent oil and liquids	61 %	65 %	68 %
Estimated proved undeveloped reserves:			
Oil (MMBbls)	39.5	28.5	39.0
Natural gas (Bcf)	139.7	112.5	106.4
Natural gas liquids (MMBbls)	17.1	11.8	10.6
Total estimated proved undeveloped reserves (MMBoe)[(2)]	79.9	59.0	67.3
Percent oil and liquids	71 %	68 %	74 %

(1) Proved reserves were calculated using the preceding twelve-month unweighted arithmetic average of the first-day-of-the-month prices, which were $66.56 per Bbl WTI and $3.60 per MMBtu HH, $39.57 per Bbl WTI and $1.99 per MMBtu HH, and $55.85 per Bbl WTI and $2.58 per MMBtu HH for the years ended December 31, 2021, 2020, and 2019, respectively. Adjustments were made for location and grade.
(2) Determined using the ratio of 6 Mcf of natural gas to one Bbl of crude oil.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion. Proved undeveloped reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic productivity at greater distances.

Proved undeveloped locations in our December 31, 2021 reserve report are included in our development plan and are scheduled to be drilled within five years from the year they were initially recorded. Annually, management creates a capital expenditure plan based on our best available data at the time the plan is developed. The development plan is based upon management's evaluation of a number of qualitative and quantitative factors including estimated risk-based returns, estimated well density, commodity prices and cost forecasts, recent drilling results and well performance, and anticipated availability of services, equipment, supplies and personnel. Currently, all PUDs in our reserve report are planned to be developed within the next two and one-half years, well within the allotted five-year window. Generally, the Company books proved undeveloped locations within one development spacing area from developed producing locations. For the instances where a proved undeveloped location is beyond one spacing area from a developed producing location, the Company utilized reliable geologic and engineering technology inclusive of, but not limited to, pressure performance, geologic mapping, offset productivity, electric logs, seismic, and production data.

As of December 31, 2021, we had 234 gross proved undeveloped locations compared to 216 gross for the comparable period in 2020. Of the total gross proved undeveloped locations at December 31, 2021, approximately 78% and 22% are scheduled to be drilled at 4 to 8 wells per section and 9 to 16 wells per section, respectively. Wells per section are estimated based on equivalent spacing between wells for a 640-acre section.

Total estimated proved reserves at December 31, 2021 increased 279.5 MMBoe, or 236%, to 397.7 MMBoe when compared to December 31, 2020. A summary of the Company's changes in quantities of proved reserves for the year ended December 31, 2021 is as follows:

	Net Reserves (MBoe)
Beginning of year	118,192
Extensions and discoveries	36
Production	(8,595)
Removed from capital program	(24,054)
Purchases of minerals in place[(1)]	332,093
Revisions to previous estimates	(19,982)
End of year	397,690

(1) Includes all changes made to acquired reserves since the closing date of the Extraction and Crestone Peak mergers.

The 24.1 MMBoe of PUD demotions is due to those locations being removed from the five-year drilling program as we high-graded our drilling program and refined our PUD booking philosophy. The 332.1 MMBoe of purchases of minerals in place is comprised of 42.5 MMBoe, 166.8 MMBoe, and 122.8 MMBoe from the HighPoint, Extraction, and Crestone Peak mergers, respectively. The negative revision to previous estimates of 20.0 MMBoe is the result of removing 13.1 MMBoe of reserves due to converting the variable well operating expense cost model to a fixed cost model which shortened economic well lives, removing 6.9 MMBoe due to engineering revisions, removing 7.1 MMBoe for changes in other items including fuel gas, interests, shrink, yield, and differentials, offset by a positive pricing revision of 7.1 MMBoe resulting from an increase in average commodity price from $39.57 per Bbl WTI and $1.99 per MMBtu HH for the year ended December 31, 2020 to $66.56 per Bbl WTI and $3.60 per MMBtu HH for the year ended December 31, 2021.

Reconciliation of Proved Reserves PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure. Neither our PV-10 measure nor the Standardized Measure purports to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to Standardized Measure at December 31, 2021, 2020, and 2019 (in millions):

	December 31,		
	2021	2020	2019
PV-10	$ 5,327.2	$ 437.1	$ 858.1
Present value of future income taxes discounted at 10%[(1)]	(915.1)	—	—
Standardized Measure	$ 4,412.1	$ 437.1	$ 858.1

(1) The tax basis of our oil and gas properties as of December 31, 2021, 2020, and 2019 provides more tax deduction than income generated from our oil and gas properties when the reserve estimates were prepared using $66.56 per Bbl WTI and $3.60 per MMBtu HH, $39.57 per Bbl WTI and $1.99 per MMBtu HH, and $55.85 per Bbl WTI and $2.58 per MMBtu HH, respectively.

Proved Undeveloped Reserves

	Net Reserves (MBoe) As of December 31, 2021
Beginning of year	59,020
Converted to proved developed	(14,151)
Additions from capital program	36
Removed from capital program	(24,054)
Acquisitions, net[(1)]	62,963
Revisions	(3,963)
End of year	79,851

(1) Includes all changes made to acquired reserves since the closing date of the Extraction and Crestone Peak mergers.

As of December 31, 2021, our proved undeveloped reserves were 79.9 MMBoe, all of which are scheduled to be drilled within five years from the year they were initially recorded. During 2021, the Company converted 24% of its proved undeveloped reserves, which is comprised of 58 gross wells representing net reserves of 14.2 MMBoe, at a cost of $111.2 million. The net decrease of 24.1 MMBoe in PUD demotions is the result of removing 91 PUD locations as they were no longer part of our five-year drilling program. The acquisition of 63.0 MMBoe in net PUD volumes is the result of adding 22.6 MMBoe and 40.4 MMBoe net reserves due to the Extraction and Crestone Peak mergers, respectively. No PUD volumes were added as a result of the HighPoint Merger. Negative revisions of 4.0 MMBoe were due to a combination of reductions related to the revised well operating cost model and adjustments to the accounting of fuel gas, shrink, and yields, partially offset by an increase in commodity pricing of 4.2 MMBoe.

Internal controls over reserves estimation process

Our policies regarding internal controls over the recording of reserves estimates require reserves to be in compliance with SEC definitions and guidance and prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. The Company’s Audit Committee reviews significant reserve changes on an annual basis, and our third-party independent reserve engineers are engaged by and have direct access to the Audit Committee. The reserves estimates shown herein have been independently prepared by Ryder Scott for the years ended December 31, 2021 and 2020 and by NSAI for the year ended December 31, 2019. These reserve estimates are reviewed by our in-house petroleum engineer who oversees and controls preparation of the reserve report data by working with our third-party independent reserve engineers to ensure the integrity, accuracy, and timeliness of data furnished for their evaluation process. The Company's technical person who was primarily responsible for overseeing the preparation of our reserve estimates was our Senior Manager, Reserves Engineering, who has 34 years of experience in the oil and gas industry, including 5 years in her role at the Company. Her professional qualifications include a bachelor's degree in Mathematics from the Colorado School of Mines.

Independent Reserve Engineers

The reserves estimates shown herein for December 31, 2021 and 2020 have been prepared by Ryder Scott, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. Ryder Scott was founded in 1937 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-1580. Within Ryder Scott, the technical person primarily responsible for preparing the estimates set forth in the Ryder Scott reserves report incorporated herein is Scott Wilson. Scott Wilson, a Licensed Professional Engineer in the State of Colorado (No. 36112), has been practicing consulting petroleum engineering at Ryder Scott since 2000 and has over 35 years of industry experience. He graduated from Colorado School of Mines in 1983 with a Bachelor of Science in Petroleum Engineering and from the University of Colorado in 1985 with a Master's of Business Administration. The responsible party 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 and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

The reserves estimates shown herein for December 31, 2019 were prepared by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein were Mr. Benjamin W. Johnson and Mr. John G. Hattner. Mr. Johnson, a Licensed Professional Engineer in the State of Texas (No. 124738), had been practicing consulting petroleum engineering at NSAI since 2007 and had over 2 years of prior industry experience. He graduated from Texas Tech University in 2005 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Hattner, a Licensed Professional Geoscientist in the State of Texas, Geophysics (No. 559), had been practicing consulting petroleum geoscience at NSAI since 1991, and had over 11 years of prior industry experience. He graduated from the University of Miami, Florida, in 1976 with a Bachelor of Science Degree in Geology; from Florida State University in 1980 with a Master of Science Degree in Geological Oceanography; and from Saint Mary's College of California in 1989 with a Master of Business Administration Degree. Both technical principals met or exceeded 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; both were proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Production, Revenues and Price History

Oil and natural gas prices fluctuated significantly during 2020 and 2021. Oil prices are impacted by production levels, inventory levels, real or perceived geopolitical risks in oil producing regions, the relative strength of the U.S. dollar, weather, and global demand. We reevaluate our development plan based on oil and natural gas prices, however, generally speaking, the Company strategy is focused on maintaining production broadly flat, growing primarily through consolidation.

Sensitivity Analysis

If oil and natural gas SEC prices declined by 10%, our proved reserve volumes would decrease by 1% and our PV-10 value as of December 31, 2021 would decrease by approximately 16% or $859.7 million. If oil and natural gas SEC prices increased by 10%, our proved reserve volumes would increase by 1% and our PV-10 value as of December 31, 2021 would increase by approximately 16% or $865.4 million.

Production

The following table sets forth information regarding oil, natural gas, and natural gas liquids production, sales prices, and production costs in the Wattenberg Field (our sole operating location) for the periods indicated. For additional information on price calculations, please see information set forth in *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations*.

	For the Year Ended December 31,		
	2021	2020	2019
Oil:			
Production (MBbls)	9,384.6	5,019.4	5,135.9
Average sales price (per Bbl), including derivatives(3)	$ 42.49	$ 44.41	$ 52.12
Average sales price (per Bbl), excluding derivatives(3)	$ 65.41	$ 34.42	$ 51.89
Natural Gas:			
Production (MMcf)	36,763.4	14,165.7	11,966.8
Average sales price (per Mcf), including derivatives(4)	$ 2.43	$ 1.40	$ 2.10
Average sales price (per Mcf), excluding derivatives(4)	$ 3.84	$ 1.45	$ 2.06
Natural Gas Liquids:			
Production (MBbls)	4,933.6	1,858.2	1,431.1
Average sales price (per Bbl), including derivatives	$ 32.84	$ 10.39	$ 11.22
Average sales price (per Bbl), excluding derivatives	$ 34.68	$ 10.39	$ 11.22
Oil Equivalents:			
Production (MBoe)	20,445.4	9,238.6	8,561.5
Average Daily Production (Boe/d)	56,015	25,242	23,456
Average Production Costs (per Boe)(1)(2)	$ 3.41	$ 4.00	$ 4.35

(1) Excludes ad valorem and severance taxes.
(2) Represents lease operating expense and midstream operating expense per Boe using total production volumes.
(3) Crude oil sales excludes \$1.0 million, \$1.7 million, and \$2.4 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2021, 2020, and 2019, respectively.
(4) Natural gas sales excludes \$3.6 million, \$3.7 million, and \$3.7 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2021, 2020, and 2019, respectively.

Customers

We believe the loss of any one customer would not have a material effect on our financial position or results of operations because there are numerous potential customers for our product.

Delivery Commitments

The Company is party to a number of purchase agreements to deliver fixed determinable quantities of crude oil, gas, and NGLs. These agreements include defined volume commitments over terms ending in 2023 and 2029. Under the terms of these agreements, the Company is required to make periodic deficiency payments for any shortfalls in delivering minimum gross volume commitments, which are set in six-month to one-year periods. Please refer to *Part II, Item 8, Note 6 - Commitments and Contingencies* for additional discussion.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells in which we owned a working interest at December 31, 2021.

	Oil		Natural Gas		Total		Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain	3,374	2,245.7	36	25.5	3,410	2,271.2	2,838	2,221.6

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2021, along with the PV-10 value. Acreage related to royalty, overriding royalty, and other similar interests is excluded from this summary.

	Developed Acres(1)		Undeveloped Acres(2)		Total Acres		PV-10
	Gross	Net	Gross	Net	Gross	Net	(in millions)
DJ Basin	495,100	387,200	139,700	94,300	634,800	481,500	
Other Rocky Mountain	109,800	37,000	25,300	18,200	135,100	55,200	
Total	604,900	424,200	165,000	112,500	769,900	536,700	$ 5,327.2

(1) Developed acreage is acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease.
(2) Undeveloped acreage 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.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. We intend to extend our strategic leases to the extent possible, and decisions to let leasehold expire generally relate to areas outside of our core area of development or when the expirations do not pose material impacts to development plans or reserves. The following table sets forth the undeveloped acreage, as of December 31, 2021, that will expire in the years indicated unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

	Expiring 2022		Expiring 2023		Expiring 2024		Expiring 2025 and Beyond	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain	39,500	26,900	24,000	12,200	3,200	2,700	31,900	25,500

Drilling Activity

The following table sets forth the exploratory and development wells completed (operated and non-operated) during the years ended December 31, 2021, 2020, and 2019.

	Year Ended December 31,					
	2021		2020		2019	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive Wells	—	—	—	—	—	—
Dry Wells	—	—	—	—	—	—
Total Exploratory	—	—	—	—	—	—
Development						
Productive Wells	100	86.2	9	8.5	45	34.1
Dry Wells	—	—	—	—	—	—
Total Development	100	86.2	9	8.5	45	34.1
Total	100	86.2	9	8.5	45	34.1

The following table describes the present operated drilling activities as of December 31, 2021.

	As of December 31, 2021	
	Gross	Net
Exploratory	—	—
Development	15	12.8
Total	15	12.8

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Derivative Activity

In addition to supply and demand, oil, natural gas, and NGL prices are affected by seasonal, economic, local, and geo-political factors that we can neither control nor predict. We attempt to mitigate a portion of our exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows through the use of derivative contracts. As of December 31, 2021, the Company had entered into the following commodity price derivative contracts:

	Crude Oil (NYMEX WTI)		Natural Gas (NYMEX Henry Hub)		Natural Gas (CIG)		Natural Gas Liquids (OPIS)	
	Bbls/day	Weighted Avg. Price per Bbl	MMBtu/day	Weighted Avg. Price per MMBtu	MMBtu/day	Weighted Avg. Price per MMBtu	Bbls/day	Weighted Avg. Price per Bbl
1Q22								
Collar	15,700	$43.83/$59.77	—	—	20,000	$2.15/$2.75	—	—
Swap	15,371	$47.39	125,170	$2.90	10,000	$2.13	4,000	$20.22
Oil roll swap(1)	2,000	$0.22	—	—	—	—	—	—
2Q22								
Collar	8,800	$38.09/$67.48	60,375	$2.50/$3.50	20,000	$2.15/$2.75	—	—
Swap	10,139	$49.84	53,300	$2.77	10,000	$2.13	4,000	$20.22
Oil roll swap(1)	2,000	$0.22	—	—	—	—	—	—
3Q22								
Collar	7,681	$40.35/$69.99	78,420	$2.59/$3.68	—	—	—	—
Swap	9,359	$46.88	53,300	$2.77	10,000	$2.13	4,000	$20.22
Oil roll swap(1)	2,000	$0.22	—	—	—	—	—	—
4Q22								
Collar	6,938	$40.75/$70.99	76,929	$2.60/$3.69	—	—	—	—
Swap	8,686	$46.77	53,300	$2.77	10,000	$2.13	4,000	$20.22
Oil roll swap(1)	2,000	$0.22	—	—	—	—	—	—
2023								
Collar	260	$40.00/$72.70	2,184	$2.00/$3.25	—	—	—	—
Swap	200	$46.05	43,600	$2.51	—	—	—	—
2024								
Swap	—	—	22,309	$2.57	—	—	—	—

(1) The weighted average differential represents the amount of reduction to NYMEX WTI prices for the notional volumes covered by the swap contracts.

The Company did not enter into any commodity price derivative contracts subsequent to December 31, 2021 through the filing of this report other than those novated from Bison as described in *Part II, Item 8, Note 14 - Subsequent Events.*

Title to Properties

Our properties are subject to customary royalty interests, overriding royalty interests, obligations incident to operating and joint venture agreements, liens for current taxes, other industry-related constraints, and certain other leasehold restrictions. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business. We believe that we have satisfactory title to all of our producing properties. Although title to our properties is subject to complex interpretation of multiple conveyances, deeds, reservations, and other instruments that serve to affect mineral title, we believe that none of these risks will materially detract from the value of our properties or from our interest therein or otherwise materially interfere with the operation of our business.

Competition

The oil and natural gas industry is highly competitive, and we compete with a substantial number of other companies that often have greater resources. Many of these companies explore for, produce, and market oil and natural gas, carry on refining operations, and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, attracting and retaining qualified personnel, and obtaining transportation for the oil and natural gas we produce. There is also competition between producers of oil and natural gas and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by federal, state, and local governments; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing, or producing oil and natural gas and may prevent or delay the commencement or continuation of certain operations. The effect and potential impacts of these risks are difficult to accurately predict.

Further, oil and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because approximately 63% of our estimated proved reserves as of December 31, 2021 were oil and natural gas liquids reserves, our financial results are more sensitive to movements in oil prices. During the year ended December 31, 2021, the daily NYMEX WTI oil spot price ranged from a high of $85.64 per Bbl to a low of $47.47 per Bbl, and the NYMEX natural gas HH spot price ranged from a high of $23.86 per MMBtu to a low of $2.43 per MMBtu.

Insurance Matters

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business, either because such insurance is not available or customary, or because premium costs are considered cost-prohibitive. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations, or cash flows.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state, and local laws and regulations. In particular, oil and natural gas production and related operations are, or have been, subject to price controls, taxes, and numerous other laws and regulations. The jurisdictions in which we own and operate properties or assets for oil and natural gas production have statutory provisions regulating the exploration for and production of oil and natural gas, including, among other things, provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the production and operation of wells and other facilities, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the proper abandonment of wells and pipelines. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area and size of associated facilities, and the unitization or pooling of oil and natural gas wells, and regulations that generally prohibit the venting or flaring of natural gas and that impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties and the suspension or cessation of operations. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations. The regulatory burden on the industry can increase the cost of doing business and negatively affect profitability. Because such laws and regulations are frequently revised and amended through various legislative actions and rulemakings, it is difficult to predict the future costs or impact of compliance. Additional rulemakings that affect the oil and natural gas industry are regularly considered at the federal, state, and various local government levels, including statutorily and through powers granted to various agencies that regulate our industry, and various court actions. We cannot predict when or whether any such rulemakings may become effective or if the outcomes will negatively affect our operations.

We believe that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows, or results of operations. However, it is difficult to estimate the potential impact on our business from existing regulations adopted by the Colorado Oil and Gas Conservation Commission ("COGCC") in November 2020 pursuant to Colorado Senate Bill 19-181, discussed herein, as well as ongoing rulemaking, which impose a number of new and amended requirements on our operations. These requirements could make it more difficult and costly to develop new oil and natural gas wells and to continue to produce existing wells, increase our costs of compliance and doing business, and delay or prevent development in certain areas or under certain conditions. The COGCC's rulemaking efforts are still ongoing, and thus we cannot assure that the existing rules, as implemented, or the pending rulemaking, will not have a material and adverse impact on our financial position, cash flows, or results of operations. In addition, the current regulatory requirements may change, currently unforeseen incidents may occur, or past noncompliance with laws or regulations may be discovered, any of which could likewise have a material adverse effect on our financial position, cash flows, or results of operations.

Regulation of production

The production of oil and natural gas is subject to regulation under a wide range of local, state, and federal statutes, rules, orders, and regulations. Federal, state, and local statutes and regulations require, among other things, permits for drilling operations, drilling bonds, and reports concerning operations. Colorado, the state in which we own and operate the vast majority of our properties, has regulations governing conservation matters, including provisions for the spacing and unitization or pooling of oil and natural gas properties, the regulation of well spacing and well density, and procedures for proper plugging and abandonment of wells and associated facilities. These regulations effectively identify well densities by geologic formation and the appropriate spacing and pooling unit size to effectively drain the resources. Operators can apply for exceptions to such regulations, including applications to increase well densities to more effectively recover the oil and gas resources. Moreover, Colorado imposes a production or severance tax with respect to the production and sale of oil, natural gas, and natural gas liquids within its jurisdiction.

We own interests in properties located onshore in primarily one U.S. state, Colorado. This state regulates drilling and operating activities by requiring, among other things, permits for the drilling of wells, best management practices and/or conditions of approval for operating wells, maintaining bonding requirements in order to drill or operate wells, regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. Colorado laws also govern a number of environmental matters, including setbacks from buildings, schools, and other occupied areas, sensitive habitats and/or disproportionately impacted communities, consideration of alternative locations for new wells, the handling and disposal of waste materials, prevention of venting and flaring, mitigation of noise, lighting, visual, odor, and dust impacts, air pollutant emissions permitting, protection of certain wildlife habitat, protection of public health, safety, welfare, and environment, and evaluation of cumulative impacts.

Regulation of transportation of oil

Our sales of crude oil are affected by the availability, terms, and cost of transportation. Interstate transportation of oil by pipeline is regulated by FERC pursuant to the Interstate Commerce Act ("ICA"), the Energy Policy Act of 1992, and the rules and regulations promulgated under those laws. The ICA and its implementing regulations require that tariff rates for interstate service on oil pipelines, including interstate pipelines that transport crude oil and refined products (collectively referred to as "petroleum pipelines"), be just and reasonable and non-discriminatory and that such rates and terms and conditions of service be filed with FERC.

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 way that is materially different from how it affects operations of our competitors who are similarly situated.

Regulation of transportation and sales of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act ("NGPA") and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act ("NGA"), and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

FERC issued a series of orders in 1996 and 1997 to implement its open access policies. As a result, the interstate pipelines' traditional role as wholesalers of natural gas has been greatly reduced and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

The Domenici Barton Energy Policy Act of 2005 ("EP Act of 2005") is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC. The EP Act of 2005 provides FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increases FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of the EP Act of 2005, and subsequently denied rehearing. The rules make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation more accessible to natural gas services subject to the jurisdiction of FERC, for any entity, directly or indirectly, (1) to use or employ any device, scheme, or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases, or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point-of-sale locations. State regulation of natural gas gathering facilities generally includes various safety, environmental, and, in some circumstances, nondiscriminatory-take requirements. Although nondiscriminatory-take regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts, or Congress.

Our sales of natural gas are also subject to requirements under the Commodity Exchange Act ("CEA"), and regulations promulgated thereunder by the Commodity Futures Trading Commission ("CFTC"). The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in the state in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is materially different from how it affects operations of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action FERC will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers, and marketers with which we compete.

Regulation of derivatives

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") was passed by Congress and signed into law in July 2010. The Dodd-Frank Act is designed to provide a comprehensive framework for the regulation of the over-the-counter derivatives market with the intent to provide greater transparency and reduction of risk between counterparties. The Dodd-Frank Act subjects swap dealers and major swap participants to capital and margin requirements and requires many derivative transactions to be cleared on exchanges. The Dodd-Frank Act provides for a potential exemption from these clearing and cash collateral requirements for commercial end-users.

Environmental, Health and Safety Regulation

Our natural gas and oil exploration and production operations are subject to numerous stringent federal, state, and local laws and regulations governing safety and health, the discharge of hazardous materials into the environment, or otherwise relating to protection of the environment or natural resources, noncompliance with which can result in substantial administrative, civil, and criminal penalties and other sanctions, including suspension or cessation of operations. These laws and regulations may, among other things, require the acquisition of permits and other approvals before drilling or other regulated activity commences; restrict the types, quantities, and concentrations of various substances that can be released into the environment; require the assessment and mitigation of potential surface impacts; govern the sourcing and disposal of water used in the drilling and completion process; limit or prohibit drilling activities that have certain impacts or that occur in certain areas; require some form of investigation or remedial action to prevent or mitigate pollution from former and ongoing legacy operations such as plugging low-producing wells or closing earthen pits; establish specific safety and health criteria addressing worker, public health, and natural resource protection and impose substantial liabilities or curtail operations for unpermitted pollutant emissions or failure to comply with regulatory filing obligations. Cumulatively, these laws and regulations may impact our operations.

The following is a summary of the more significant existing environmental and health and safety laws and regulations to which we are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations, or financial position.

Air emissions

The Clean Air Act ("CAA") and comparable state and local laws and regulations restrict the emission of air pollutants from many sources, including oil and gas operations, and impose various monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification and operation of certain projects or facilities expected to produce or significantly increase air emissions, obtain and comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining required air permits can significantly delay the development of certain oil and natural gas projects. Over the next several years, we may be required to incur certain expenditures for air pollution control equipment or other air emissions-related issues.

Federal Air Regulation

In May 2016, the U.S. Environmental Protection Agency (the "EPA") issued additional New Source Performance Standards ("NSPS") rules, known as Subpart OOOOa, focused on achieving additional methane and volatile organic compound reductions from oil and natural gas operations. Among other things, these revisions imposed new requirements for leak detection and repair, control requirements for oil well completions, and additional control requirements for gathering, boosting, and compressor stations. On September 14, 2020, the EPA finalized the Review Rule rescinding certain prior source category determinations for the transmission and storage segments and parts of the 2016 rules regulating methane emissions for the oil and gas industry. Separately, on September 14, 2020, the EPA finalized the Reconsideration Rule that made policy and technical amendments to the NSPS rules that were raised in administrative petitions that include proposed changes to, among other things, the frequency for monitoring fugitive emissions at well sites and compressor stations. On January 20, 2021, President Biden issued an Executive Order directing the EPA to rescind the Reconsideration Rule by September 2021. Both Rules are subject to ongoing litigation, and therefore, future obligations continue to remain uncertain under the Clean Air Act. On November 2, 2021, the Environmental Protection Agency ("EPA") proposed a suite of NSPS program rules, known as Subparts OOOOb and OOOOc that, if adopted, will have a further impact on the upstream and midstream oil and gas sectors. As proposed, Subparts OOOOb and OOOOc will impact new, modified, existing and/or reconstructed sources in the oil and natural gas sector. The proposed regulations include additional inspections, emission control requirements, and additional financial assurance for plugged and abandoned wells. The proposed rules for new and modified facilities are estimated to be finalized by the end of 2022, while any standards finalized for existing facilities will require further state rulemaking actions over the next several years before they become applicable and effective.

In October 2015, the EPA finalized its rule lowering the earlier 75 part per billion ("ppb") national ambient air quality standards ("2008 NAAQS") for ozone under the CAA to 70 ppb ("2015 NAAQS"). The state of Colorado's Denver Metro and North Front Range ("DM/NFR") air quality control region has been unable to attain the 2008 and 2015 ozone NAAQS since their adoption, and received a bump-up in its existing non-attainment status for the 2008 NAAQS from "moderate" to "serious" in 2019. Oil and natural gas operations in "serious" ozone non-attainment areas, including in the DM/NFR area, are subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements for new and modified facilities, and increased permitting delays and costs. Additionally, The DM/NFR's non-attainment boundary for the 2015 NAAQS was successfully challenged by environmental groups and local governments seeking to expand the boundary to include all of northern Weld County in the case of *Clean Wisconsin v. EPA*, No. 18-1203, in which the D.C. Circuit remanded the boundary determination to the EPA for further support or re-designation. In response, the EPA chose to re-designate the boundary for the 2015 ozone NAAQS to include all of Weld County, which action became effective on December 30, 2021. Weld County has challenged the EPA's action upon remand in the D.C. Circuit, and the case is pending briefing on the merits and is not likely to be decided until late 2022 or early 2023. *Bd. of County Comm. of Weld County v. EPA*, No. 21-1263. Finally, a "severe" non-attainment status designation for the DM/NFR by the EPA appears likely for the 2008 NAAQS in early 2022 due to violations at area monitors during the 2020 ozone season. A "severe" classification would trigger significant additional obligations under the CAA and state statute and will result in new and more stringent air quality control requirements applicable to our operations and significant operating costs and delays in obtaining necessary permits for new and modified production facilities. Among other requirements, a "severe" classification for the 2008 NAAQS may require additional permitting in the nonattainment area for any source with the potential to emit more than 25 tons per year of volatile organic compounds or nitrogen oxides.

In May 2016, the EPA also finalized a rule regarding source determination, including defining the term "adjacent" under the CAA, which affects how major sources are defined, particularly 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 major sources, thereby triggering more stringent air permitting requirements. These EPA rulemakings will have nominal effect on our operations, because the rule clarified our existing presumption on "adjacent" and presents no conflict with the state of Colorado definitions.

The EPA also published Control Technique Guidelines ("CTGs") in October 2016 aimed at providing states with guidance and setting a presumptive floor for Reasonably Achievable Control Technology ("RACT") for the oil and gas industry in areas of ozone non-attainment, including the DM/NFR area. In November 2017, as required following issuance of the CTGs, the Colorado Air Quality Control Commission AQCC adopted additional RACT and other air quality regulations that increased emissions control, monitoring, recordkeeping, and reporting requirements on oil and gas operators in the DM/NFR area, and to some extent state-wide.

State Air Regulation

In February 2014, the Colorado Department of Public Health and Environment's Air Quality Control Commission ("AQCC") adopted new and revised air quality regulations that imposed stringent new requirements to control emissions from both existing and new or modified oil and gas facilities in Colorado. The regulations included new emissions control, monitoring, recordkeeping, and reporting requirements, as well as a Leak Detection and Repair ("LDAR") program for well production facilities and compressor stations. The LDAR program primarily targets hydrocarbon (i.e., methane) emissions from the oil and gas sector in Colorado and represents a significant new use of state authority regarding these emissions.

In December 2019, the AQCC adopted new and revised air quality regulations that extended the controls adopted in 2014 to many lower producing and emitting facilities statewide, and added storage tank loadout controls to those requirements, among other changes. The new rules also increased the frequency of LDAR monitoring to semi-annual for lower producing facilities previously subject to a one-time monitoring requirement, as well as monthly LDAR monitoring for facilities within 1,000 ft. of occupied areas, and imposed a new emission inventory and reporting of greenhouse gases ("GHGs"), among other requirements. Some of these new requirements became effective as early as January 30, 2020, with others requiring compliance by May 1, 2020, or May 1, 2021. Colorado's Air Quality Control Commission also revised rules specific to the oil and gas sector in September 2020, and again in December 2020. The September 2020 rules revisions included emission control requirements for natural gas fired engines typically in compression service, for pre-production tanks used in flowback, and also established a preproduction air monitoring plan requirement for operators for the first time. The December 2020 regulatory changes also included further revisions to LDAR monitoring requirements within 1,000 ft. of occupied areas.

In February 2021, the AQCC also adopted regulations requiring the use of non-emitting pneumatic controllers at both new and existing facilities. This requirement is based on a company-wide percentage of pneumatic controllers being non-emitting. Additionally, in December 2021, the AQCC adopted still further air emissions control requirements specific to the oil and natural gas industry including increased LDAR monitoring frequencies, additional pneumatic controller emissions reduction and elimination requirements, enclosed combustion device testing requirements, and company-wide GHG intensity reductions, among other things. These updated regulations are aimed in substantial part at achieving GHG and conventional pollutant emission reductions from Colorado's oil and gas industry in response to legislative directives, including Colorado House Bill 19-1261, which set ambitious GHG emission targets, and House Bill 21-1266, which modified those targets, among other things.

Each of the above AQCC rulemakings are intended to further Colorado's legislative directive to reduce GHG emissions to attain climate action goals. AQCC is expected to undertake several rulemaking efforts to further reduce emissions in the next several years.

In November 2020, the COGCC adopted new regulations that generally prohibit the venting or flaring of natural gas during drilling, completion, and production operations, with limited exceptions, using its expanded oil and gas conservation and environmental protection authority under Colorado Senate Bill 19-181, discussed herein. Among other things, these regulations require that operators proposing new oil and gas wells either commit to connecting to a gathering system when production commences or submit a gas capture plan.

Compliance with these and other air pollution control, gas capture and permitting requirements has the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could be significant.

Hydraulic fracturing

Regulations relating to hydraulic fracturing. We are subject to extensive federal, state, and local laws and regulations concerning health, safety, and environmental protection. Government authorities frequently add to those requirements, and both oil and gas development generally and hydraulic fracturing specifically are receiving increasing regulatory attention. Our operations utilize hydraulic fracturing, an important and commonly used process in the completion of oil and natural gas wells in low-permeability formations. Hydraulic fracturing involves the injection of water, proppant, and chemicals under pressure into rock formations to stimulate hydrocarbon production.

States have historically regulated oil and gas exploration and production activity, including hydraulic fracturing. The state government where we operate has adopted or is considering adopting additional requirements relating to hydraulic fracturing that could restrict its use in certain circumstances or make it more costly to utilize. Such measures may address any risk to drinking water, the potential for hydrocarbon migration, the disclosure of the chemicals used in fracturing, or other matters. Colorado, for example, requires operators to reduce hydrocarbon emissions associated with hydraulic fracturing, prepare and report significant data regarding oil and gas impacts, compile and report additional information regarding wellbore integrity, publicly disclose the chemical ingredients used in hydraulic fracturing, maintain minimum distance between occupied structures and oil and gas wells, undertake additional mitigation for nearby residents, and implement additional groundwater testing. Any enforcement actions or requirements of additional studies or investigations by governmental authorities where we operate could increase our operating costs and cause delays or interruptions to our operations.

The federal Safe Drinking Water Act ("SDWA") and comparable state statutes may restrict the disposal, treatment, or release of water produced or used during oil and gas development. Subsurface emplacement of fluids, primarily via disposal wells or enhanced oil recovery ("EOR") wells, is governed by federal or state regulatory authorities that, in some cases, include the state oil and gas regulatory or the state's environmental authority. The federal Energy Policy Act of 2005 amended the Underground Injection Control provisions of the SDWA to expressly exclude certain hydraulic fracturing from the definition of "underground injection," but disposal of hydraulic fracturing fluids and produced water or their injection for EOR is not excluded.

Federal agencies have periodically considered additional regulation of hydraulic fracturing. The EPA has published guidance for issuing underground injection permits that would regulate hydraulic fracturing using diesel fuel. This guidance eventually could encourage other regulatory authorities to adopt permitting and other restrictions on the use of hydraulic fracturing. As noted above, in June 2016, the EPA finalized regulations that address discharges of wastewater pollutants from onshore unconventional extraction facilities to publicly-owned treatment works, and after a legal challenge by environmental groups, in July 2019, the EPA declined to revise the rules. The EPA also published a study of the impact of hydraulic fracturing on drinking water resources in December 2016, which concluded that drinking water resources can be affected by hydraulic fracturing under specific circumstances. The results of this study could result in additional regulations, which could lead to operational burdens similar to those described above. The United States Department of the Interior also finalized a rule regulating hydraulic fracturing activities on federal lands, including requirements for disclosure, wellbore integrity, and handling of flowback water; however, on December 29, 2017, the Bureau of Land Management ("BLM") issued a rescission of the hydraulic fracturing rule. This rescission and the rule as promulgated are subject to ongoing litigation. Additionally, in early 2016, the BLM proposed rules related to further controlling the venting and flaring of natural gas on BLM land. Following the adoption of these rules in late 2016, a group led by the states of Wyoming and Montana, later joined by North Dakota and Texas, challenged the rules in the United States District Court for the District of Wyoming. On September 28, 2018, the BLM published a final rule that revised the 2016 rules. The new rule, among other things, rescinded the 2016 rule requirements related to waste-minimization plans, gas-capture percentages, well drilling, well completion and related operations, pneumatic controllers, pneumatic diaphragm pumps, storage vessels, and leak detection and repair. The new rule also revised provisions related to venting and flaring. Environmental groups and the states of California and New Mexico filed challenges to the 2018 rule in the United States District Court for the Northern District of California. In July of 2020, the California court vacated the 2018 revisions but stayed its vacatur of the rules for 90 days. On October 8, 2020, before the 90-day stay of the California court's vacatur expired, the Wyoming court struck down the 2016 rules on the grounds that the BLM exceeded its statutory authority by adopting rules to protect air quality, a role delegated to the EPA. The federal government appealed the decision from California and the citizen groups, New Mexico, and California appealed the decision from Wyoming. The Spring 2021 Unified Agenda of Regulatory and Deregulatory Actions, published by the Office of Management and Budget's Office of Information and Regulatory Affairs, identified a potential proposal by the BLM to update its existing rules governing the venting and flaring of natural gas from onshore Federal and Indian oil and gas leases. The BLM has not yet published such a proposed rule. Future litigation regarding the 2016 and 2018 rules and any alternative future rule therefore creates some uncertainty as to how BLM's regulation of venting and flaring will impact our business.

Apart from these ongoing federal and state initiatives, some state and local governments have adopted their own new requirements on hydraulic fracturing and other oil and gas operations. At the state level, voters in Colorado have proposed or advanced initiatives restricting or banning oil and gas development in Colorado, but these initiatives have failed to date. Further, Colorado Senate Bill 19-181 amended state law to give municipalities and counties greater local control over siting and permitting of oil and gas locations, and some municipalities within the state have implemented regulations within their jurisdictions. Any successful bans or moratoriums where we operate, whether at the state or local level, could increase the costs of our operations, impact our profitability, and even prevent us from drilling in certain locations which could threaten our production targets. In addition, in light of concerns about seismic activity being triggered by the injection of produced waters into underground wells, certain regulators have adopted or are considering additional requirements related to seismic safety for hydraulic fracturing activities or the underground injection of fluid wastes. For example, the regulations that the COGCC adopted in November 2020 impose various new requirements on the underground injection of fluid wastes to further seismic safety and protect the environment. Any regulation that restricts our ability to dispose of produced waters or increases the cost of doing business could have a material adverse effect on our business.

At this time, it is not possible to estimate the potential impact on our business of recent state and local actions or the enactment of additional federal or state legislation or regulations affecting hydraulic fracturing. The adoption of future federal, state, or local laws or implementing regulations imposing new environmental obligations on, or otherwise limiting, our operations could make it more difficult and more expensive to complete oil and natural gas wells, increase our costs of compliance and doing business, delay or prevent the development of certain resources (including especially shale formations that are not commercial without the use of hydraulic fracturing), or alter the demand for and consumption of our products. We cannot assure that any such outcome would not be material, and any such outcome could have a material and adverse impact on our cash flows and results of operations.

Our use of hydraulic fracturing. We use hydraulic fracturing as a means to maximize production of oil and gas from formations having low permeability such that natural flow is restricted. Fracture stimulation has been used for decades in the Rocky Mountain region.

Typical hydraulic fracturing treatments are made up of water, chemical additives, and sand. We utilize major hydraulic fracturing service companies who track and report additive chemicals that are used in fracturing as required by the appropriate government agencies, including FracFocus, the national hydraulic fracturing chemical registry managed by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission. Each of the service companies we use fracture stimulate a multitude of wells for the industry each year.

We periodically review our plans and policies regarding oil and gas operations, including hydraulic fracturing, in order to minimize any potential environmental impact. Our operations are subject to close supervision by state and federal regulators (including the BLM with respect to federal acreage), who frequently inspect our fracturing operations.

Other State Laws

Our properties located in Colorado are subject to the authority of the COGCC, as well as other state agencies. The COGCC finalized new flowline rules in February 2018. The new rules include increased registration requirements, flowline design requirements, integrity management requirements, leak detection programs, and requirements for abandonment of flowlines. In November 2019, the COGCC further amended its flowline rules to impose additional requirements regarding flowline mapping, operational status, certification, and abandonment, among other things. Over the past several years, the COGCC has also approved new rules regarding various other matters, including wellbore integrity, hydraulic fracturing, well control, waste management, spill reporting, spacing of wells and pooling of mineral interests, and an increase in potential sanctions for COGCC rule violations.

In 2016, the Colorado Supreme Court ruled that the cities of Fort Collins and Longmont do not have authority to ban oil and gas operations within their jurisdictional limits. In January 2019, in *Martinez v. COGCC*, the Colorado Supreme Court rejected an argument that Colorado’s oil and gas statute contained a requirement that COGCC condition new oil and gas development on a finding of no cumulative adverse impacts to public health and the environment. In April 2019, Colorado Senate Bill 19-181 (SB 181) became effective, which substantially changes the state’s regulation of oil and gas exploration and production activities and was enacted in partial response to the Fort Collins/Longmont and *Martinez* decisions. SB 181 changes the COGCC's mission from “fostering” responsible and balanced development “consistent with protection” of public health and the environment to “regulating” development “to protect” public health and the environment. SB 181 also instituted several state-wide regulatory changes, namely (i) changed the composition of the COGCC to remove two seats for industry experts and add experts on wildlife/environmental protection and public health, and changed the Commissioners’ employment from volunteer to full-time positions, (ii) changed Colorado’s statutory pooling provisions to require that an applicant own, or obtain the consent of, more than 45% of the applicable working or mineral interest, whereas previously the consent of only one mineral interest owner was required, (iii) changed state pre-emption law such to afford local governments greater control over oil and gas siting, and (iv) initiated a comprehensive rulemaking to amend COGCC's rules consistent with the agency's revised mission.

Among the most significant changes under SB 181 was the aforementioned provision giving local governments greater control over facility siting and surface impacts associated with oil and gas development. Whether an applicable local government determines to implement regulatory changes is optional, but if changes are adopted, the resulting regulations may be stricter than state requirements. Further, local governments may now inspect oil and gas operations and impose fines for leaks, spills, and emissions. Regulation in the municipalities and areas where we operate could result in increased costs, delays in securing permits and other approvals related to our operations, and otherwise materially bear on our ability to operate and drill new wells in the areas where we hold oil and gas interests. At this time, it impossible to estimate the potential impact on our business of future local actions on our ability to operate and/or drill oil and gas wells in these areas.

The COGCC has adopted significant additional regulations to implement SB 181 as part of its historic "mission change" rulemaking. The legislation mandated COGCC rulemaking on environmental protection, facility siting, cumulative impacts, flowlines, wells that are inactive, temporarily abandoned, or shut-in, financial assurance, wellbore integrity, and application fees. The COGCC completed rulemaking on flowlines and wells that are inactive, temporarily abandoned, or shut-in in November 2019, completed rulemaking on wellbore integrity in June 2020, and completed a major rulemaking on the COGCC's "mission change" in November 2020. The mission change rulemaking was intended to align the regulations to the COGCC's new mission. It addressed a wide range of topics including facility siting, cumulative impacts, development approvals, asset transfers, pollution standards, hearings and variances, groundwater monitoring, underground injection control and enhanced recovery wells, venting and flaring restrictions, spill reporting, cleanup responsibility, and wildlife protection. The mission change rules took effect on January 15, 2021, and they apply to permit applications pending on or submitted after that date and generally to operations occurring on or after that date. The agency is currently in the process of issuing written guidance on many of the issues addressed to provide direction on regulatory interpretation and compliance. The COGCC has undertaken rulemaking on financial assurance, application fees, and high priority habitat during 2021 that is expected to conclude in early 2022. It is expected a result of the financial assurance rulemaking will be to increase the amounts that operators are required to provide as a surety bond for assurance that wells will be properly plugged and abandoned at the end of their lifecycle. Depending on how these and any other new rules are applied and enforced, they could add substantial increases in well costs for our Colorado operations. The rules could also impact our ability to operate and extend the time necessary to obtain drilling permits, which would create substantial uncertainty about our ability to meet future drilling plans and thus production and capital expenditure targets.

SB 181 also required the state's AQCC to undertake rulemaking efforts to minimize methane emissions and emissions of other hydrocarbons, volatile organic compounds and nitrogen oxides associated with certain oil and gas facilities. The AQCC adopted more stringent standards for leak detection and repair inspection frequency, pipeline and compressor station inspection and maintenance frequencies, and for reducing emissions from pneumatic devices, and expanded storage tank control and loadout control requirements applicable statewide in December 2019, as noted above. The legislation also grants the AQCC regulatory authority over a broad range of oil and gas facilities during pre-production activities, drilling and completion.

Hazardous substances and waste handling

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that transported, disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these potentially responsible parties may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies, and 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. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as or contain CERCLA hazardous substances but we are not aware of any liabilities for which we may be held responsible that would materially or adversely affect us.

The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal, and cleanup of hazardous wastes, and distinguishes between hazardous and non-hazardous or solid wastes. With the approval of the EPA, the individual states can administer some or all of the provisions of RCRA, and some states have adopted their own, more stringent hazardous waste requirements, while all states regulate solid waste. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development, and production of natural gas and oil are currently regulated under RCRA's non-hazardous waste provisions and state solid waste laws. However, legislation has been proposed from time to time and various environmental groups have filed lawsuits that, if successful, could result in the reclassification of certain oil and natural gas exploration and production wastes as "hazardous wastes," which would make such wastes subject to much more stringent and costly handling, disposal, and clean-up requirements. For example, in May 2016, several environmental groups filed a lawsuit in the U.S. District Court for the District of Columbia that sought to compel the EPA to review and, if necessary, revise its regulations regarding existing exemptions for exploration and production related wastes. On December 28, 2016, the EPA entered into a consent decree with those environmental groups to settle the lawsuit, which required the EPA by March 15, 2019 to either propose new regulations regarding exploration and production related wastes or sign a determination that revision of such regulations is not necessary. Pursuant to the consent decree, the EPA determined in April 2019 that revision of the regulations is unnecessary. The EPA indicated that it will continue to work with states and other organizations to identify areas for continued improvement and to address emerging issues to ensure that exploration, development, and production wastes continue to be managed in a manner that protects human health and the environment. Environmental groups, however, expressed dissatisfaction with the EPA's decision and will likely continue to press the issue at the federal and state levels, especially under the new Biden Administration.

In 2018, the Colorado State legislature passed Senate Bill 245 that gave the Colorado Department of Public Health & Environment ("CDPHE") the authority to promulgate rules for the safe management of Technologically Enhanced Naturally Occurring Radioactive Material ("TENORM"). TENORM is naturally occurring radioactive material whose radionuclide concentrations are increased through human activity, such as through generation of water treatment residuals, scales and sediments from oil and gas production, and other processes. The bill required the Department to review TENORM residual management and regulatory limits from other states as well as prepare a report that considers background radiation levels in the state, waste stream identification and quantification, use and disposal practices, current engineering practices, appropriate test methods, economic impacts, and data gaps. This work was completed by CDPHE in 2019. During 2020, CDPHE promulgated new rules governing TENORM waste, which were adopted in November 2020 and became effective January 14, 2021, but are not enforceable until July 14, 2022, to provide operators time to come into compliance. During drilling, completion, and production, numerous waste streams that may contain TENORM are created that are hauled for disposal at permitted disposal facilities. CDPHE is developing three guidance documents and holding stakeholder meetings to help impacted facility operators characterize existing materials, make a TENORM determination and prepare for compliance with the new rules in 2022. Depending on the final waste streams chosen for characterization and regulatory levels set for disposal, costs for characterization, storage, and disposal of waste could significantly increase.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore for and produce oil and natural gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, exploration and production fluids and gases may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons and wastes were not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA, and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including groundwater contaminated by prior owners or operators), to pay for damages for the loss or impairment of natural resources, and to take measures to prevent future contamination from our operations.

In addition, other laws require the reporting on use of hazardous and toxic chemicals. For example, in October 2015, the EPA granted, in part, a petition filed by several national environmental advocacy groups to add the oil and gas extraction industry to the list of industries required to report releases of certain "toxic chemicals" under the Toxic Release Inventory ("TRI") program under the Emergency Planning and Community Right-to-Know Act. The EPA determined that natural gas processing facilities may be appropriate for addition to TRI applicable facilities and in January 2017, the EPA issued a proposed rule to include natural gas processing facilities in the TRI program. In November 2021, the EPA added natural gas processing facilities to the scope of the industrial sectors covered by the TRI Program. This rule expands coverage to include all natural gas processing facilities that receive and refine natural gas, not just those operated primarily to recover sulfur, which were already included.

Pipeline safety and maintenance

Pipelines, gathering systems, and terminal operations are subject to increasingly strict safety laws and regulations. Both the transportation and storage of refined products and crude oil involve a risk that hazardous liquids may be released into the environment, potentially causing harm to the public or the environment. In turn, such incidents may result in substantial expenditures for response actions, significant penalties, liability for natural resources damages, and significant business interruption. The U.S. Department of Transportation has adopted safety regulations with respect to the design, construction, operation, maintenance, inspection, and management of our pipeline and storage facilities. These regulations contain requirements for the development and implementation of pipeline integrity management programs, which include the inspection and testing of pipelines and the correction of anomalies. These regulations also require that pipeline operation and maintenance personnel meet certain qualifications and that pipeline operators develop comprehensive spill response plans.

There have been recent initiatives to strengthen and expand pipeline safety regulations and to increase penalties for violations. The Pipeline Safety, Regulatory Certainty, and Job Creation Act was signed into law in early 2012. In addition, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") has issued new rules to strengthen federal pipeline safety enforcement programs. In 2015, PHMSA proposed to expand its regulations in a number of ways, including through the increased regulation of gathering lines, even in rural areas. In 2016, PHMSA increased its regulations to require crude oil sampling and reporting as an "offeror" (as defined under the PHMSA) and increased its civil penalty structure. In November 2021, PHMSA issued its final rule extending reporting requirements to all onshore gas gathering operators and applying a set of minimum safety requirements to certain onshore gas gathering pipelines with large diameters and high operating pressures.

In Colorado, the Public Utilities Commission ("PUC") adopted amended Rules Regulating Pipeline Operators and Gas Pipeline Safety for intrastate pipelines on December 16, 2020. Following public and stakeholder comment, an Administrative Law Judge for the PUC issued a Recommended Decision on November 4, 2020, recommending that the PUC formally adopt proposed revisions. On March 17, 2021, Regulation 11 rules Regulating Pipeline Operators and Gas Pipeline Safety were adopted by the Public Utilities Commission. These regulations apply to all gas public utilities, all municipal or quasi-municipal corporations transporting natural gas or providing natural gas services, all operators of master meter systems, and all operators of pipelines transporting gas in intrastate commerce including gas gathering system operators (certain provisions are tailored to the location and size of the gathering systems involved). The rules require all filed reports to be publicly available and all Notices of Proposed Violation, Notices of Action, pleadings and decisions to be filed publicly. The rules also provide a revised methodology for calculating civil penalties in an effort to provide clarity to both operators and the public.

Climate change

Based on EPA findings that emissions of carbon dioxide, methane, and other GHGs present an endangerment to public health and the environment, the EPA adopted regulations under the CAA that, among other things, established Prevention of Significant Deterioration ("PSD"), construction, and Title V operating permit reviews for GHG emissions from certain large stationary sources that are already major sources of emissions of regulated air pollutants. In a subsequent ruling, the U.S. Supreme Court upheld a portion of the EPA's GHG stationary source program, but also invalidated a portion of it, holding that stationary sources already subject to the PSD or Title V program for non-GHG criteria pollutants remained subject to GHG BACT requirements, but that sources subject to the PSD or Title V program only for GHGs could not be forced to comply with the EPA's GHG Best Available Control Technology ("BACT") requirements. Upon remand, the D.C. Circuit issued an amended judgment, which, among other things, vacated the PSD and Title V regulations under review in that case to the extent they require a stationary source to obtain a PSD or Title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. In October 2016, the EPA issued a proposed rule to further revise its PSD and Title V regulations applicable to GHGs in accordance with these court rulings, including a proposed de minimis level of GHG emissions below which BACT is not required. This rulemaking process was not finalized. If the EPA promulgates new rules under the Biden Administration, it is possible that any regulatory or permitting obligation that limits emissions of GHGs could extend to smaller stationary sources and require us to incur costs to reduce and monitor emissions of GHGs associated with our operations, and may also adversely affect demand for the oil and natural gas that we produce.

In addition, the EPA has adopted rules requiring the monitoring and reporting of GHGs from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the EPA's GHG emissions reporting rule and Colorado's GHG emissions inventory and reporting rules more recently adopted.

In August of 2015, the EPA finalized rules to further reduce GHG emissions, primarily from coal-fired power plants, under its Clean Power Plan ("CPP"). On March 28, 2017, President Trump signed an Executive Order directing the EPA to review the CPP regulations. Following the Executive Order, on April 4, 2017, the EPA announced that it was formally reviewing the CPP. On October 9, 2017, the EPA published a proposed rule to repeal the Clean Power Plan and on July 8, 2019, the EPA finalized the Affordable Clean Energy ("ACE") rule, which established emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants. The ACE rule replaced the CPP and provided states with new emission guidelines that informed their development of standards of performance to reduce carbon dioxide (CO2) emissions from existing coal-fired power plants. Long-pending legal challenges to the CPP rule filed by states, industry and environmental groups were dismissed as moot by the D.C. Circuit Court of Appeals on September 17, 2019, given the issuance of a final replacement ACE rule. On January 19, 2021, the D.C. Circuit struck down the ACE Rule and remanded it to the EPA, which has stated power sector regulation of GHGs is a high priority, but has not indicated when a replacement rule might be forthcoming.

On October 29, 2021, the U.S. Supreme Court agreed to review the D.C. Circuit's decision striking down the ACE rule in four distinct petitions. In its review of these cases, the Supreme Court will examine the scope of the EPA's authority to regulate GHGs under Section 111(d) of the Clean Air Act. While the Supreme Court's ruling in these cases will be specific to the power sector, it could also have legal implications for other existing sources of GHGs, like those in the oil and natural gas exploration sector.

Congress has, from time to time, considered but not yet passed legislation to reduce emissions of GHGs. In addition, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs.

Additional GHG regulation may also result from the December 2015 agreement that the United States reached during the December 2015 United Nations climate change conference in Paris, France (the "Paris Agreement"). Within the Paris Agreement, the United States agreed to reduce its GHG emissions by 26-28% by the year 2025 as compared with 2005 levels, and provide periodic updates on its progress. On June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement. Although former President Trump's announced withdrawal finally took effect on November 4, 2020, among President Biden's first actions was the issuance of an executive order and the provision of 30-day advance notice to the United Nations of the United States' return to the Paris Agreement. The U.S. returned to participation in the U.N. Framework Convention on Climate Change 26th Conference of the Parties held in Glasgow, Scotland in November 2021, advancing a Global Methane Pledge along with the European Union, which over 100 countries representing almost 70% of global GDP have signed, among other initiatives, pledges and agreements.

On May 30, 2019, Colorado also passed GHG inventory legislation and climate action legislation. House Bill 19-1261 concerns the reduction of greenhouse gas pollution and established statewide greenhouse gas pollution reduction goals. Senate Bill 19-096 concerns the collection of greenhouse gas emissions data to facilitate measures to cost-effectively meet the states GHG emissions reduction goals established in HB 19-1261. Regulations implementing the GHG inventory requirements of these statutes were promulgated by the Colorado Air Quality Control Commission in May of 2020 and became effective on July 15, 2020. Additionally, on September 30, 2020, the Colorado Energy Office and Colorado Department of Public Health and Environment released a draft Greenhouse Gas Pollution Reduction Roadmap for public comment and finalized the document on January 14, 2021. The GHG Roadmap lays out a pathway to meet the state's climate action targets established in HB 19-1261, as amended by HB 21-1266.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting, emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Severe limitations on GHG emissions could adversely affect our production operations and/or demand for the oil and natural gas we produce. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could also reduce demand for the oil and natural gas we produce. In addition, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds, and other sources of capital restricting or eliminating their investment in oil and natural gas activities. As well, as an oil and gas producer there are potential reputational risks and negative perceptions associated with our operations and the growing concern around GHG emissions and climate change.

Water discharges

The Federal Water Pollution Control Act or the Clean Water Act ("CWA") and analogous state laws impose restrictions and controls regarding the discharge of pollutants into certain surface waters of the U.S., including spills and leaks of hydrocarbons and produced water. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control, and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil. As properties are acquired, we determine the need for new or updated SPCC plans and, where necessary, will develop or update such plans to implement physical and operation controls, the costs of which are not expected to be material. In June 2015, the EPA and the U.S. Army Corps of Engineers (the "Corps") adopted a new regulatory definition of jurisdictional "waters of the U.S." ("WOTUS"), which was repealed by the EPA on October 22, 2019, restoring the 1986 regulatory definition of "Waters of the United States," – step one of a two-step process. Then in January 2020, the EPA and the Corps released the Navigable Waters Protection Rule which updated the federal definition for a WOTUS – the second step in the two-step process to repeal and replace the 2015 rule – and published the final rule on April 21, 2020. The Navigable Waters Protection Rule went into effect on June 22, 2020, but numerous environmental, agricultural and business groups and state governments challenged the rule in various courts, and the rule was vacated by two separate federal district courts in late 2021. On November 18, 2021, the EPA and the Corps issued a pre-publication version of another WOTUS rule largely reinstating the previous 1986 WOTUS rule and guidance "with certain amendments" to reflect "consideration of the agencies' statutory authority under the CWA and relevant Supreme Court decisions" (the "2021 Proposed Rule"). The 2021 Proposed Rule was published in the Federal Register on December 7, 2021.

In addition to the 2021 Proposed Rule, the EPA and the Corps plan to develop yet another amendment to the WOTUS regulations, which will build upon the regulatory foundation in the 2021 Proposed Rule with the benefit of additional stakeholder engagement and public input. It is unknown at this time when the 2021 Proposed Rule will take effect; when the next forthcoming proposed amendments are expected; and/or whether either new rule will be challenged and withstand any challenges in federal court.

In May 2020, a federal court in Montana enjoined the use of nationwide permit ("NWP") 12 to construct new oil and gas-related pipelines, on the basis that the Corps had not properly consulted with the U.S. Fish and Wildlife Service when that permit was renewed in 2017 (the court later amended its ruling to allow use of NWP 12 for non-oil and gas transmission projects). The U.S. Supreme Court in July 2020 significantly narrowed the Montana court's injunction to cover only the challenged XL Pipeline. On August 11, 2021, the Ninth Circuit granted partial vacatur of the Corps' appeal of the Montana district court's opinion, holding the claim before it (the interlocutory appeals and underlying claim relative to the pipeline, which has been halted) was moot, but left to the district court the question of whether the case was moot in its entirety.

In the meantime, in September 2020 and again in January 2021, the Corps issued proposals to revise and reissue all 52 current NWPs, including No. 12, to, among other things, lessen the burden on the energy industry and address the flaws alleged in the Montana lawsuit. Although there are small differences in the September 2020 and January 2021 proposals, they do not impact the changes described below, particularly with NWP 12. The new NWPs became effective in March 2021.

Among other things, under the new NWPs, existing NWP 12 was broken up into three new separate NWPs, with the new NWP 12 being limited solely to construction and maintenance of oil and gas pipelines, with other utility-related structures covered by the two new NWPs (i.e., NWP 57 for electric utility line and telecommunications activities and NWP 58 for utility line activities for water and other substances). The new 2021 version of NWP 12 has again been challenged in the District of Montana, by the same plaintiffs on the same grounds, which case is still pending. If the 2021 version of NWP 12 ultimately is invalidated or stayed by the courts, it could increase the costs and delays for oil and gas operators to construct or maintain pipelines that cross jurisdictional WOTUS.

Finally, in January 2022, the United States Supreme Court granted review of *Sackett vs. EPA*, which involves issues related to CWA scope and jurisdiction and could impact the current rulemaking process. Although the outcome of the 2021 Proposed Rule and additional forthcoming amendments to the WOTUS regulations are unknown, the regulations under the Biden Administration will undoubtedly be more stringent in terms of the scope of WOTUS, which could ultimately change the scope of the CWA's jurisdiction and result in increased costs and delays with respect to obtaining permits for discharges of pollutants or dredge and fill activities in waters of the U.S., including regulated wetland areas.

Endangered Species Act and Migratory Bird Treaty Act

The federal Endangered Species Act ("ESA") restricts activities that may affect endangered and threatened species or their habitats. In August 2019, the U.S. Fish and Wildlife Service (the "FWS") and National Marine Fisheries Service issued three rules amending implementation of the ESA regulations revising, among other things, the process for listing species and designating critical habitat. A coalition of states and environmental groups have challenged the three rules and the litigation remains pending. In addition, on December 18, 2020, the FWS amended its regulations governing critical habitat designations. We anticipate the rule will be subject to litigation. A final rule amending how critical habitat and suitable habitat areas are designated was finalized by the U.S. Fish and Wildlife Service in 2016. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act ("MBTA"), which makes it illegal to, among other things, hunt, capture, kill, possess, sell, or purchase migratory birds, nests, or eggs without a permit. This prohibition covers most bird species in the U.S. On January 7, 2021, the Department of the Interior finalized a rule limiting application of the MBTA, however the Department of the Interior under President Biden delayed the effective date of the rule and opened a public comment period for further review. Based on that review, the Department of Interior published a final rule on October 4, 2021, revoking the January 7, 2021, regulations that limited the scope of the MBTA. With this revocation of the January 7, 2021 rule, the U.S. Fish and Wildlife Service returns to implementing the MBTA as prohibiting incidental take and applying enforcement discretion, consistent with long-standing agency practice prior to 2017. This final rule went into effect on December 3, 2021. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. The designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Employee health and safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act ("OSHA"), and comparable state statutes, the purpose of which are to protect the health and safety of workers. In 2016, there were substantial revisions to the regulations under OSHA that may impact our operations. These changes include among other items: record keeping and reporting, a revised crystalline silica standard (which requires the oil and gas industry to implement engineering controls and work practices to limit exposures below the new limits by June 23, 2021), naming oil and gas as a high hazard industry, and requirements for a safety and health management system. In addition, OSHA's hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations, and that this information be provided to employees, state and local government authorities, and citizens. In November 2021, OSHA issued a Temporary Emergency Standard ("TES") with respect to COVID-19 vaccination or masking and testing. The TES was withdrawn as an enforceable temporary emergency standard on January 26, 2022; however, OSHA has not withdrawn the TES as a proposed rule and is focused on finalizing a permanent COVID-19 standard for General Industry.

National Environmental Policy Act

Natural gas and oil exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major federal actions having the potential to significantly impact the human environment. In the course of such evaluations, an agency will evaluate the potential direct, indirect, and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a detailed environmental impact statement that is made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. The vast majority of our exploration and production activities are not on federal lands. This environmental review process has the potential to delay or limit, or increase the cost of, the development of natural gas and oil projects on federal lands. Authorizations under NEPA also are subject to protest, appeal, or litigation, which can delay or halt projects. On July 16, 2020, the Council on Environmental Quality ("CEQ") revised NEPA's implementing regulations to make the NEPA process more efficient, effective, and timely. The final rule requires federal agencies to develop procedures consistent with the new rule within one year of the rule's effective date. The new regulations are subject to ongoing litigation in several federal district courts, and on October 7, 2021, CEQ issued a notice of proposed rulemaking to amend the NEPA regulatory changes adopted in 2020 in two phases. Where Phase I of the CEQ's proposed rulemaking process would generally restore provisions that were in effect prior to 2020, it is anticipated that Phase II of the proposed rulemaking would propose further revisions to ensure the NEPA process "provides for efficient and effective environmental reviews," and meets environmental, environmental justice, and climate change objectives. The CEQ's proposed changes could result in increased NEPA review timelines for projects involving agency action regarding federal lands, federal money, or federal permits or approvals.

Oil Pollution Act

The Oil Pollution Act of 1990 ("OPA") establishes strict liability for owners and operators of facilities that release oil into waters of the U.S. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the U.S. The OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction, or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA. The OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

Human Capital

As of December 31, 2021, the Company had 322 employees, of which 19 were transition employees and 59 were dedicated to the operation of our midstream assets. The Company's diverse team of talented employees possess a vast array of skills including engineering, geology, research and development, midstream operations, production, logistics and administrative support, such as accounting, information technology, legal, human resources and finance. Certain of the Company's employees have highly specialized skills and subject-matter expertise in their respective fields, which helps enable the Company to deliver industry leading innovation and results.

The Company attracts and maintains talent by offering market rate competitive salaries for the locations in which it operates, and by engaging employees with rewarding opportunities to contribute to the success of the Company. The Company is committed to supporting and developing its employees through learning and development programs. These programs are designed to build and strengthen employees' skills, including leadership and professional competencies. Such efforts also include routine and consistent compliance training, covering a wide-range of relevant subjects. The Company has consistently re-invested in necessary resources to effectively staff and efficiently support its business.

Employee health and safety in the workplace is one of the Company's core values. Safety efforts are led by the Environmental, Health, and Safety & Regulatory Compliance ("EHS&RC") team and supported by individuals at the local site level. Hazards in the workplace are timely identified, and management actively tracks incidents so remedial actions may be implemented to improve workplace safety. The Company also provides an injury case management program that provides medical management services tailored to any injured employee to best meet their recovery needs. Additionally, all field employees attend training provided by the COGCC or by the EHS&RC department to proactively ensure compliance and adherence related to recently issued rules and regulations. In response to the COVID-19 pandemic, the Company has taken actions aligned with the World Health Organization and the Centers for Disease Control and Prevention to protect its workforce so they can more safely and effectively perform their work. In so doing, the Company has prioritized the initiation of comprehensive health and safety protocols, further ensuring strict adherence to responsive measures for mitigating the spread of COVID-19.

The Nominating and Corporate Governance Committee of the Board (the "Governance Committee") considers diversity as a criteria evaluated as part of the attributes and qualifications that a Board candidate possesses. The Governance Committee construes the notion of diversity broadly, considering differences in viewpoint, professional experience, education, skills and other individual qualities, in addition to race, gender, age, ethnicity and cultural backgrounds as elements that contribute to a diverse Board. The Company is committed to efforts to increase diversity and foster an inclusive work environment that supports the Company's workforce.

We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages.

Offices

As of December 31, 2021, we leased office space in Denver, Colorado at 555 17th Street where our principal offices are located. Additionally, we own and lease various field offices in Colorado.

Available Information

We are required to file annual, quarterly, and current reports, proxy statements and other information with the SEC. Our filings with the SEC are available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange under the symbol “CIVI.” Our reports, proxy statements, and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website at http://civitasresources.com all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website is not incorporated by reference into this Annual Report on Form 10-K.

Item 1A. *Risk Factors.*

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, financial condition, or results of operations could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect us.

Summary of the Risk Factors We Face:

- Declines in oil, natural gas, and NGL prices will adversely affect our business, financial condition or results of operations, and our ability to meet our capital expenditure obligations or targets and financial commitments.
- Our production is not fully hedged, and we intend to hedge a lower percentage of our production than we have in the past. We are therefore exposed to fluctuations in the price of oil, natural gas, and NGLs and will be affected by continuing and prolonged declines in such prices.
- Our derivative activities could result in financial losses or could reduce our income.
- The full extent to which COVID-19 pandemic impacts our business, results of operations, and financial condition will depend on future developments, which cannot be predicted.
- The agreements governing our debt have restrictive covenants that could limit our growth and our ability to finance our operations, fund capital needs, respond to changing conditions, and engage in other business activities that may be in our best interests.
- Borrowings under the Credit Facility are limited by our borrowing base, which is subject to periodic redetermination.
- Our exploration, development, exploitation, and production projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of our leases or a decline in our oil and natural gas reserves or anticipated production volumes.
- Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition, or results of operations.
- Our estimated proved reserves and our ultimate number of prospective well development locations are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
- We intend to pursue the further development of our properties in the DJ Basin and Wattenberg Field through horizontal drilling and completion, which can be more operationally challenging and costly relative to our historic vertical drilling operations.
- We may be unable to make attractive acquisitions, and any inability to do so may disrupt our business and hinder our ability to grow.
- We may not realize anticipated benefits from acquisitions, including the Extraction Merger, the Crestone Peak Merger, and the Bison Acquisition.
- Concentration of our operations in one core area may increase our risk of production loss.
- As a Colorado-only oil and gas operator, we face disproportionate risk associated with the long-term trend toward increased activism against oil and gas exploration and development activities in Colorado.
- The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.
- Drilling locations that we decide to drill may not yield oil or natural gas in commercially viable quantities.
- Certain of our undeveloped leasehold acreage is subject to leases that will expire over next several years unless production is established on units containing the acreage or leases are extended through additional payments.

- Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition, and results of operations.
- We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks, including those related to our hydraulic fracturing operations.
- We are subject to health, safety, and environmental laws and regulations that may expose us to significant costs and liabilities.
- Evolving environmental legislation or regulatory initiatives, including those related to hydraulic fracturing, could result in increased costs and additional operating restrictions or delays.
- Climate change laws and regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas that we produce, while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.
- The negative shift in investor sentiment of the oil and gas industry could have adverse effects on our ability to raise debt and equity capital and on our operations.
- We are exposed to credit risks of our hedging counterparties, third parties participating in our wells, and our customers.
- Current or proposed financial legislation and rulemaking could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate, and other risks associated with our business.
- We may be involved in legal cases that may result in substantial liabilities.
- We are subject to federal, state, and local taxes and may become subject to new taxes, and certain federal income tax deductions and state income tax deductions and exemptions currently available with respect to oil and gas exploration and development may be eliminated or reduced as a result of future legislation.
- The Extraction Merger and the Crestone Peak Merger triggered a limitation on the utilization of our historic U.S. net operating loss carryforwards ("NOLs"), Extraction's NOLs and Crestone Peak's NOLs.
- The Extraction Merger and the Crestone Peak Merger has caused increased exposure to risks regarding urban encroachment, increased activism against oil and gas exploration, urban and suburban density, and residential expansion in the areas in which we operate.
- We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption, or financial loss.
- The market price for our common stock following the Extraction Merger and the Crestone Peak Merger may be affected by factors different from those that historically have affected or currently affect our common stock.
- We have experienced recent volatility in market price and trading volume of our common stock and may continue to do so in the future.
- Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, even if such acquisition or merger may be in our stockholders' best interests
- Our certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, or other employees.

Risks Related to Our Business

Declines in oil, natural gas, and NGL prices will adversely affect our business, financial condition or results of operations, and our ability to meet our capital expenditure obligations or targets and financial commitments.

The price we receive for our oil, natural gas, and natural gas liquids (“NGLs”), heavily influences our revenue, profitability, cash flows, liquidity, access to capital, present value and quality of our reserves, the nature and scale of our operations, and future rate of growth. 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. In recent years, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Because approximately 63% of our estimated proved reserves as of December 31, 2021 were oil and NGLs, our financial results are more sensitive to movements in oil and NGL prices.

During times of suppressed oil prices, we have historically experienced significant decreases in crude oil revenues and recorded unproved property asset impairment charges. Any prolonged period of low market prices for oil, natural gas, and NGLs or further declines in the market prices for oil and natural gas, could result in future capital expenditures being further reduced and will necessarily adversely affect our business, financial condition, and liquidity and our ability to meet obligations, targets, or financial commitments. During the year ended December 31, 2021, the daily NYMEX WTI oil spot price ranged from a high of $85.64 per Bbl to a low of negative $47.47 per Bbl, and the NYMEX natural gas HH spot price ranged from a high of $23.86 per MMBtu to a low of $2.43 per MMBtu. As of March 4, 2021, the daily NYMEX WTI oil spot price and NYMEX natural gas HH spot price was $115.68 per Bbl and $5.02 per MMBtu, respectively.

The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- worldwide and regional, and local economic conditions impacting the global supply and demand for oil and natural gas;
- the actions from members of the Organization of Petroleum Exporting Countries and other oil producing nations;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and involving Russia and Ukraine and conditions in South America;
- the level of domestic and global oil and natural gas exploration and production;
- the level of domestic and global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions and natural disasters;
- local, domestic and foreign governmental regulations;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- the price and availability of competitors’ supplies of oil and natural gas;
- technological advances affecting energy consumption;
- variability in subsurface reservoir characteristics, particularly in areas with immature development history, even within areas in close proximity within the same basin or field;
- the availability of pipeline capacity and infrastructure; and
- the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under contracts at market-based prices. Declines in commodity prices may have the following effects on our business:

- reduction of our revenues, profit margins, operating income and cash flows;

- reduction in the amount of crude oil, natural gas, and NGLs that we can produce economically, and reduction in our liquidity and inability to pay our liabilities as they come due;
- certain properties in our portfolio becoming economically unviable;
- delay or postponement of some of our capital projects;
- significant reductions in future capital programs, resulting in a reduced ability to develop our reserves;
- limitations on our financial condition, liquidity, and/or ability to finance planned capital expenditures and operations;
- reduction to the borrowing base under our Credit Facility or limitations in our access to sources of capital, such as equity or debt;
- declines in our stock price;
- reduction in industry demand for crude oil;
- reduction in storage availability for crude oil;
- reduction in pipeline and processing industry demand and capacity for natural gas;
- reduction in the ability of our vendors, suppliers, and customers to continue operations due to the prevailing adverse market conditions; and
- asset impairment charges resulting from reductions in the carrying values of our crude oil and natural gas properties at the date of assessment.

Imbalances between the supply and demand for oil and natural gas could result in transportation and storage constraints, reductions of our planned production, and related shut-in of our wells, which could adversely affect our business, financial condition, and results of operations.

Beginning in March 2020, the uncertainty regarding the impact of COVID-19 and various governmental actions taken to mitigate the impact of COVID-19 resulted in an unprecedented decline in demand for oil and natural gas. This resulted in excess supply that led to transportation and storage capacity constraints in the United States, including in the DJ Basin where we operate. While the threats caused to our business by COVID-19 have since been substantially mitigated, the pandemic has been and continues to be volatile and unpredictable. A worsening of the COVID-19 pandemic, or the occurrence of other events that negatively impact demand for oil and natural gas, could result in excess supply for a sustained period.

Any future excess supply of oil and natural gas could impact our ability to sell our production because of transportation or storage constraints, causing us to shut-in or curtail production or flare our natural gas. Any such prolonged shut-in of our wells may result in decreased well productivity once we are able to resume operations, and any cessation of drilling and development of our acreage could result in the expiration, in whole or in part, of our leases. The occurrence of any of these risks may, in the future, adversely affect our business, financial condition, and results of operations.

Terrorist attacks and armed conflict could have a material adverse effect on our business, financial condition, or results of operations.

Terrorist attacks and armed conflict may significantly affect the energy industry, including our operations and those of our current and potential customers, as well as general economic conditions, consumer confidence and spending, and market liquidity. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other targets in the United States. Our insurance may not protect against such occurrences. Furthermore, commodity markets are currently also subject to heightened levels of uncertainty related to the Russian military incursion into Ukraine, which could give rise to regional instability and result in heightened economic sanctions by the U.S. and the international community that, in turn, could increase uncertainty with respect to global financial markets and production output from the Organization of Petroleum Exporting Countries and other oil producing nations. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition, and results of operations.

Our production is not fully hedged, and we intend to hedge a lower percentage of our production than we have in the past. We are therefore exposed to fluctuations in the price of oil, natural gas, and NGLs and will be affected by continuing and prolonged declines in such prices.

Oil, natural gas, and NGL prices are volatile. It is common within the industry to hedge a portion of oil and natural gas production to reduce a company's exposure to adverse fluctuations in these prices. Within our company, we have stated limitations as prescribed in our reserve-based Credit Facility, as the borrower, with JPMorgan Chase Bank, N.A., as the administrative agent, and a syndicate of financial institutions as lenders (the "Credit Facility") as to the percentage of our production that can be hedged. The limitations range from 85% to 100% of our projected production from our proved developed properties and 65% to 85% of our projected production from our total proved properties, dependent on the duration of the hedge. The Credit Facility also contains a minimum hedging covenant; however, the Credit Facility was amended on December 21, 2021 to provide that the minimum hedging covenant will no longer apply so long as the Company maintains its leverage ratio below 1.0:1. Due to the Credit Facility's restrictions and/or management's decision to hedge less than 100% of our projected production, some of our future production will be sold at market prices, exposing us to fluctuations in the price of crude oil and natural gas. Currently, we have hedged approximately 20,600 Bbls per day in 2022, representing approximately 30% of the mid-point of our oil sales volume guidance for 2022, and our hedging for 2023 oil production is even more limited. We intend to continue to hedge our production, but we may not be able to do so at favorable prices. Accordingly, our revenues and cash flows are subject to increased volatility and may be subject to significant reduction in prices, which would have a material negative impact on our results of operations. See the *Derivative Activity* section in Part I, Item I of this Annual Report on Form 10-K for a summary of our hedging activity.

Our derivative activities could result in financial losses or could reduce our income.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we have, and may in the future enter into additional, derivative arrangements for a portion of our oil, natural gas, and NGL production, including swaps, collars, and other instruments. We have not in the past designated any of our derivative instruments as hedges for accounting purposes and have recorded all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received.

In addition, these types of derivative arrangements may limit the benefit we would receive from increases in the prices for oil and natural gas and may expose us to cash margin requirements.

The extent to which the COVID-19 pandemic impacts our business, results of operations, and financial condition will depend on future developments, which cannot be predicted.

Beginning in March 2020, the outbreak of COVID-19 spread across the globe and impacted worldwide economic activity, including the global demand for oil and natural gas. To date, commodity prices for oil, natural gas, and natural gas liquids have rebounded to median historic levels. However, any COVID-19 variant-driven or unrelated public health pandemic or epidemic poses the risk that we or our employees, vendors, suppliers, customers, and other business partners may be prevented from conducting business activities for an indefinite period of time due to the potential spread of the disease within these groups or due to restrictions that may be requested or mandated by governmental authorities, including quarantines of certain geographic areas, restrictions on travel, and other restrictions that prohibit employees from going to work. The COVID-19 outbreak surfaced in all regions around the world and severely impacted the global economy, disrupted consumer spending, interrupted global supply chains, and created significant volatility and disruption of financial markets. While the emergence of vaccines and lessening of restrictions have occurred, there remains uncertainty around the ultimate severity, scope and duration of the pandemic, vaccine administration rates and efficacy, potential resurgences of COVID-19 cases and the emergence of new more contagious or vaccine-resistant virus variants.

The COVID-19 pandemic caused us to modify our business practices (including employee travel, employee work locations, and cancellation of physical participation in meetings, events, and conferences), and we may take further actions as may be required by government authorities or that we determine are in the best interests of our employees, vendors, suppliers, customers, and other business partners in response to any re-emergence or other similar threat from any other variant of COVID-19 or other worldwide biopandemic. There is no certainty that any such measures will be sufficient to mitigate the risks posed by any such pandemic or otherwise be satisfactory to government authorities.

The full extent to which COVID-19 may impact our business, results of operations, and financial condition will depend on future developments, which are uncertain and cannot be predicted, including, but not limited to, the duration and spread of the outbreak, its severity, the emergence of COVID-19 variants, the actions to contain the virus or any such variants and treat its impact, and how quickly and to what extent normal economic and operating conditions can resume. If COVID-19 or any variant continues to spread, re-emerges, or future responses to contain COVID-19 or its potential variants are unsuccessful, we could experience a material adverse effect on our business, financial condition, and results of operations. Even after the coronavirus outbreak has subsided, we may continue to experience materially adverse impacts to our business as a result of its global economic impact, including any recession that has occurred or may occur in the future.

The agreements covering our debt have restrictive covenants that could limit our growth and our ability to finance our operations, fund capital needs, respond to changing conditions, and engage in other business activities that may be in our best interests.

The agreements governing our debt, including the Credit Facility and the indentures governing our senior notes, contain restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under the Credit Facility is subject to compliance with certain financial covenants, including the maintenance of certain financial ratios, including a minimum current ratio and a maximum leverage ratio. In addition, our debt agreements contain covenants that, among other things, limit our ability to:

- incur or guarantee additional indebtedness;
- issue preferred stock;
- sell or transfer assets;
- pay dividends on, redeem, or repurchase capital stock;
- repurchase or redeem subordinated debt;
- make certain acquisitions and investments;
- create or incur liens;
- engage in transactions with affiliates;
- enter into agreements that restrict distributions or other payments from restricted subsidiaries to us;
- consolidate, merge, or transfer all or substantially all of our assets; and
- engage in certain other business activities.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our indebtedness. We may not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness. As of the date of this Annual Report on Form 10-K, we are in compliance with all financial and non-financial covenants.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants contained in our debt documents. In addition, our ability to comply with the financial ratios and financial condition tests under the Credit Facility may be affected by events beyond our control and, as a result, we may be unable to meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a continued downturn in commodity prices, our business, or the economy in general, or otherwise conduct necessary corporate activities.

Borrowings under the Credit Facility are limited by our borrowing base, which is subject to periodic redetermination.

The borrowing base under the Credit Facility is redetermined at least semiannually and up to two additional times per year between scheduled determinations upon request of us or lenders holding more than 50% of the aggregate commitments. Redeterminations are based upon a number of factors, including commodity prices and reserve levels. In addition, our lenders have substantial flexibility to reduce our borrowing base due to subjective factors.

In our fall 2021 redetermination, which was completed in connection with Amended & Restated Credit Agreement (defined below), the borrowing base under the Credit Facility was set at $1.0 billion with an elected committed amount of $800 million.

Upon a redetermination, we could be required to repay a portion of our bank debt to the extent our outstanding borrowings at such time exceed the redetermined borrowing base. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the facility and an acceleration of the loans thereunder requiring us to negotiate renewals, arrange new financing, or sell significant assets, all of which could have a material adverse effect on our business and financial results.

Our exploration, development, exploitation, and production projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of our leases or a decline in our oil and natural gas reserves or anticipated production volumes.

Our exploration, development, exploitation, and production activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production, and acquisition of oil and natural gas reserves. At this time, we intend to finance future capital expenditures primarily through cash flows provided by operating activities and borrowings under the Credit Facility. Declines in commodity prices coupled with our financing needs may require us to alter or increase our capitalization substantially through the issuance of additional equity securities or debt securities or the strategic sale of assets. The issuance of additional debt may require that a portion of our cash flows provided by operating activities be used for the payment of principal and interest on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures, and acquisitions. In addition, upon the issuance of certain debt securities (other than on a borrowing base redetermination date), our borrowing base under the Credit Facility would be reduced. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

Our cash flows provided by operating activities and access to capital are subject to a number of variables, including:

- our proved reserves;
- the amount of oil and natural gas we are able to produce from new and existing wells;
- the prices at which our oil and natural gas are sold;
- the costs of developing and producing our oil and natural gas;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of our banks to lend; and
- our ability to access the equity and debt capital markets.

If the borrowing base under the Credit Facility decreases or if our revenues decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves, or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations. If additional capital is needed, we may not be able to obtain debt or equity financing on favorable terms, or at all. If cash generated by operations or cash available under the Credit Facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our drilling locations, which in turn could lead to a possible expiration of our undeveloped leases and a decline in our oil and natural gas reserves, and an adverse effect on our business, financial condition, and results of operations.

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

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development, and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, lease, explore, develop, or otherwise exploit drilling locations or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data, and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see *Our estimated proved reserves and our ultimate number of prospective well development locations are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves* below. Our cost of drilling, completing, and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors, including, but not limited to, the following, may result in substantial losses, including personal injury or loss of life, penalties, damage or destruction of property and equipment, and curtailments, delays, or cancellations of our scheduled drilling, completion, and infrastructure projects:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions;
- unexpected operational events;
- unanticipated environmental liabilities;
- pressure or irregularities in geological formations;
- adverse weather conditions, such as extreme cold temperatures, blizzards, ice storms, tornadoes, floods, and fires;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements, such as permitting delays;
- proximity to and capacity of transportation facilities;
- title issues or inaccuracies;
- safety and/or environmental events; and
- limitations in the market for oil and natural gas.

Our estimated proved reserves and our ultimate number of prospective well development locations are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves and the production possible from our oil and gas wells is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K. See *Estimated Proved Reserves* under Part I, Item 1 of this Annual Report on Form 10-K for information about our estimated oil and natural gas reserves and the PV-10 (a non-GAAP financial measure) as of December 31, 2021, 2020, and 2019.

In order to prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production, and engineering data. The extent, quality, and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes, and availability of funds, and given the current volatility in pricing, such assumptions are difficult to make. Although the reserves information contained herein is reviewed by independent reserves engineers, estimates of oil and natural gas reserves are inherently imprecise, particularly as they relate to state-of-the-art technologies being employed, such as the combination of hydraulic fracturing and horizontal drilling.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses, and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K and cause potential impairment charges. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices, and other factors, many of which are beyond our control.

The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements for the years ended December 31, 2021, 2020, and 2019, we based the estimated discounted future net revenues from our proved reserves on the unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding twelve months (after adjustment for location and quality differentials), without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas and hedging instruments;
- actual cost of development and production activities;
- the amount and timing of actual production;
- the amount and timing of future development costs;
- wellbore productivity realizations above or below type curve forecast models;
- the supply and demand of oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor (the factor required by the SEC) used when calculating discounted future net revenues 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 oil and natural gas industry in general.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we may be required to take write-downs of the carrying values of our properties.

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics, and other factors, from time to time, we may be required to write-down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. Given the historical price volatility in the oil and natural gas markets, prices may decline or other events may arise that would require us to record further impairments of the book values associated with oil and natural gas properties. Accordingly, we may incur significant impairment charges in the future which could have a material adverse effect on our results of operations and could reduce our earnings and stockholders’ equity for the periods in which such charges are taken.

We intend to pursue the further development of our properties in the DJ Basin through horizontal drilling and completion. Horizontal development operations can be more operationally challenging and costly relative to our historic vertical drilling operations.

Horizontal drilling is generally more complex and more expensive on a per well basis than vertical drilling. As a result, there is greater risk associated with a horizontal well program. Risks associated with our horizontal drilling program include, but are not limited to, the following, any of which could materially and adversely impact the success of our horizontal drilling program and, thus, our cash flows and results of operations:

- successfully drilling and maintaining the wellbore to planned total depth;
- landing our wellbore in the desired hydrocarbon reservoir;
- effectively controlling the level of pressure flowing from particular wells;
- staying in the desired hydrocarbon reservoir while drilling horizontally through the formation;
- running our casing through the entire length of the wellbore;

- running tools and other equipment consistently through the horizontal wellbore;
- successful design and execution of the fracture stimulation process;
- preventing downhole communications with other wells, or, in the alternative, disruption from non-simultaneous operations;
- successfully cleaning out the wellbore after completion of the final fracture stimulation stage; and
- designing and maintaining efficient forms of artificial lift throughout the life of the well.

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 drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, limited takeaway capacity, or depressed natural gas and oil prices, the return on our investment in these areas may not be as attractive as anticipated. Further, as a result of any of these developments, we could incur material impairments of our oil and gas properties and the value of our undeveloped acreage could decline in the future.

We may be unable to make attractive acquisitions, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of producing properties or businesses that complement or expand our current business. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil, natural gas and NGL prices and their applicable differentials;
- operating costs;
- location inventory; 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. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is, “where is” basis. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms or for other reasons stated herein.

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. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. In addition, our Credit Facility and the indentures governing our senior notes impose certain limitations on our ability to enter into mergers or combination transactions and also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions.

We may not realize anticipated benefits from acquisitions, including the Extraction Merger, the Crestone Peak Merger, and the Bison Acquisition.

We seek to complete acquisitions in order to strengthen our position and to create the opportunity to realize certain benefits, including, among other things, potential cost savings and potential production multiples. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as being able to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations. Acquisitions could also result in difficulties in being able to hire, train or retain qualified personnel to manage and operate such properties.

With respect to the Extraction Merger, the Crestone Peak Merger, and the Bison Acquisition, we believe that the mergers and acquisition will complement our strategy by providing operational and financial scale, increasing free cash flow, and enhancing our corporate rate of return. However, achieving these goals requires, among other things, realization of the targeted cost synergies expected from the transactions, and there can be no assurance that we will be able to successfully integrate Extraction’s, Crestone Peak’s, and Bison's assets or otherwise realize the expected benefits of the transactions. This growth and the anticipated benefits of the mergers may not be realized fully or at all or may take longer to realize than expected. Difficulties in integrating Extraction and Crestone Peak, and Bison's assets, may result in the combined company performing differently than expected, or in operational challenges or failures to realize anticipated efficiencies. Potential difficulties in realizing the anticipated benefits of the mergers include:

- disruptions of relationships with customers, distributors, suppliers, vendors, landlords, joint venture partners and other business partners as a result of uncertainty associated with the Extraction Merger, the Crestone Peak Merger, and the Bison Acquisition;
- difficulties integrating our business with the businesses of Extraction, Crestone Peak, and Bison in a manner that permits us to achieve the full revenue and cost savings anticipated from the transaction;
- complexities associated with managing a larger and more complex business, including difficulty addressing possible inconsistencies in, standards, controls or operational philosophies and the challenge of integrating complex systems, technology, networks and other assets of each of the companies in a seamless manner that minimizes any adverse impact on customers, suppliers, employees and other constituencies;
- difficulties realizing anticipated operating synergies;
- difficulties integrating personnel, vendors and business partners;
- loss of key employees who are critical to our future operations due to uncertainty about their roles within our company following the recent mergers or other concerns regarding the mergers;
- potential unknown inherited liabilities and unforeseen expenses;
- performance shortfalls at the companies as a result of the diversion of management’s attention to integration efforts; and
- disruption of, or the loss of momentum in, each company’s ongoing business.

We have also incurred, and expect to continue to incur, a number of costs associated with combining the businesses of Extraction, Crestone Peak, and the Company. The elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the three companies, may not initially offset integration-related costs or achieve a net benefit in the near term, or at all.

Our future success will depend, in part, on our ability to manage our expanded business by, among other things, integrating the assets, operations or personnel of Extraction, Crestone Peak, Bison, and the Company in an efficient and timely manner; consolidating systems and management controls; and successfully integrating relationships with customers, vendors and business partners. Failure to successfully manage the combined company may have an adverse effect on our business, reputation, financial condition and results of operations.

Concentration of our operations in one core area may increase our risk of production loss.

Our assets and operations are currently concentrated in one core area: the DJ Basin and Wattenberg Field in Colorado. The core area currently provides 100% of our current sales volumes and development projects.

Because our operations are not as diversified geographically as some of our competitors, the success of our operations and our profitability may be disproportionately exposed to the effect of any regional events, including: fluctuations in prices of crude oil, natural gas, and NGLs produced from wells in the area, geologic and engineering developments associated with this area, accidents or natural disasters, restrictive governmental regulations, including ozone non-attainment, climate-action or other legislation and/or regulation within Colorado, activist anti-industry litigation, curtailment of production, interruption in the availability of gathering, processing, or transportation infrastructure and services, and any resulting delays or interruptions of production from existing or planned new wells. Similarly, the concentration of our assets within a single producing formation exposes us to risks, such as changes in field-wide rules or local regulations, which could adversely affect development activities or production relating to the formation. In addition, in areas where exploration and production activities are increasing, as has been the case in recent years in the Wattenberg Field, we are subject to increasing competition for drilling rigs, pressure pumping fleets, oilfield equipment, services, supplies, and qualified personnel, which may lead to periodic shortages or delays. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Further, the areas in which we operate are experiencing increasing urban and suburban expansion, which impacts the number of available drilling locations, increases governmental reach such as annexation and taxation, and increased costs and expenses due to limited locations, opposition, and other factors.

We do not maintain business interruption (loss of production) insurance for our oil and gas producing properties. Loss of production or limited access to reserves in our core operating area could have a significant negative impact on our cash flows and profitability.

As a Colorado-only oil and gas operator, we face disproportionate risk associated with the long-term trend toward increased activism against oil and gas exploration and development activities in Colorado.

Opposition toward oil and gas drilling and development activity has been growing globally. Companies in the oil and gas industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, environmental compliance, and business practices. Anti-development activists are working to, among other things, reduce access to fee, federal and state government lands and delay or cancel certain projects such as the development of oil or gas shale plays. For example, environmental activists continue to advocate for increased regulations or bans on shale drilling in the United States, even in jurisdictions that are among the most stringent in their regulation of the industry. Further efforts could result in the following:

- delay or denial of drilling permits;
- increased local government rulemaking and/or changes to current local government rules that result in increased costs and delay or prevention of oil and gas development;
- increased demands for additional best management practices (“BMPs”) beyond what is currently required in certain operating agreements or by the COGCC;
- revocation or modification of drilling permits, operating agreements or other necessary authorizations;
- disputes focused on the validity of active leases and record title ownership to prevent development;
- disputes focused on proximity of operations to urban and suburban communities;
- restrictions on installation or operation of production, gathering, or processing facilities;
- mandatory and excessive setbacks between drilling locations and structures and building units and/or bodies of water, disproportionately impacted communities, or other protected areas;
- restrictions on the use of certain operating practices, such as hydraulic fracturing, or the disposal of related waste materials, such as hydraulic fracturing fluids and produced water;
- increased severance and/or other taxes;
- cyber-attacks;
- legal challenges or lawsuits;
- negative publicity about us or the oil and gas industry in general;
- increased costs of operations and development;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

Specifically in Colorado, anti-development activity has both increased and become more effective in recent years. In April 2019, new legislation became effective in Colorado, which substantially changed the state’s regulation of oil and gas exploration and production activities. The new law changed the mission of the COGCC from “fostering” responsible and balanced development “consistent with protection” of public health and the environment to “regulating” oil and natural gas development “to protect” public health and the environment. SB 181 also instituted several state-wide regulatory changes, namely (i) changed the composition of the COGCC to remove two seats for industry experts and add experts on wildlife/environmental protection and public health, and changed the Commissioners’ employment from volunteer to full-time positions, (ii) changed Colorado's statutory pooling provisions to require that an applicant own, or obtain the consent of, more than 45% of the applicable working or mineral interest, whereas previously the consent of only one mineral interest owner was required, (iii) changed state pre-emption law such to afford local governments greater control over oil and gas siting, and (iv) initiated a comprehensive rulemaking to amend COGCC's rules consistent with the agency's revised mission.

Among the most significant changes under the legislation was the aforementioned provision giving local governments greater control over facility siting and surface impacts associated with oil and gas development. Whether an applicable local government determines to implement regulatory changes is optional, but if changes are adopted, the resulting regulations may be stricter than state requirements. Further, local governments may now inspect oil and gas operations and impose fines for leaks, spills, and emissions. Regulation in the municipalities and areas where we operate could result in increased costs, delays in securing permits and other approvals related to our operations, and otherwise materially bear on our ability to operate and drill new wells in the areas where we hold oil and gas interests. At this time, it impossible to estimate the potential impact on our business of future local actions on our ability to operate and/or drill oil and gas wells in these areas.

The legislation mandated the COGCC conduct rulemaking on environmental protection, facility siting, cumulative impacts, flowlines, wells that are inactive, temporarily abandoned, or shut-in, financial assurance, wellbore integrity, and application fees. The COGCC completed rulemaking on flowlines and wells that are inactive, temporarily abandoned, or shut-in in November 2019, completed rulemaking on wellbore integrity in June 2020, and completed rulemaking on the agency's "mission change" in November 2020. The mission change rulemaking addressed a wide range of topics including facility siting, cumulative impacts, development approvals, asset transfers, pollution standards, hearings and variances, groundwater monitoring, underground injection control and enhanced recovery wells, venting and flaring restrictions, spill reporting, cleanup responsibility, and wildlife protection.

The mission change rules took effect on January 15, 2021, and the agency has issued written guidance on many of the issues addressed to provide direction on regulatory interpretation and compliance. Among other things, the amended rules adopt an increased required setback of 2,000 feet between an oil and gas location and a residential or high occupancy building unit unless one or more conditions are satisfied to allow for a lesser setback that the COGCC determines is acceptable under the rules. In addition, as part of wildlife protections, the COGCC adopted a setback of 500 feet between oil and gas locations and/or certain operations thereon and the ordinary high water mark for certain high priority aquatic habitats, though the Colorado Parks and Wildlife Division may waive this setback beyond 300 feet.

Permitting delays that result from the new COGCC rules and regulations could substantially curtail the Company's near-term pace of new oil and gas development. We have observed a marked decline in the pace at which permit applications are being granted, and if this trend continues, it could have a material adverse effect on our business, financial condition, production targets, and results of operations.

Additionally, the new legislation requires the state's AQCC to undertake rulemaking efforts to minimize methane emissions and emissions of other hydrocarbons, volatile organic compounds, and nitrogen oxides associated with oil and gas facilities. The AQCC has more recently adopted more stringent standards for leak detection and repair inspection frequency, pipeline and compressor station inspection and maintenance frequencies, the development of pre-production air monitoring plans at certain oil and gas facilities, enclosed combustion device testing, a company-wide methane intensity reduction requirement and additional measures for reducing and eliminating emissions from pneumatic devices. The legislation also granted the AQCC regulatory authority over a broad range of oil and gas facilities during pre-production activities, drilling, and completion.

Rules adopted by the COGCC and AQCC pursuant to the new legislation may significantly increase the Company's operating costs and have a material adverse effect on our business, financial condition, and results of operations.

Additionally, anti-development activists succeeded in adding a measure to the November 6, 2018 ballot in Colorado, which sought to require a minimum 2,500 foot setback from occupied structures and vulnerable areas for all new oil and gas development on non-federal land. While this initiative was ultimately unsuccessful, had it been successful, it may have resulted in dramatically reducing the area of future oil and gas development in Colorado. Similar ballot measures were submitted for the 2020 election by anti-development activist groups. In addition, there have been several citizen/activist lawsuits filed against industry and state and local regulators associated with air quality, siting, environmental justice, and climate change. Such anti-development efforts are likely to continue in the future, which could result in dramatically reducing the area of future oil and gas development in Colorado or outright banning oil and gas development in Colorado. These efforts could have a material adverse effect on our business, financial condition, and results of operations.

SB 181's requirement that we own or control more than 45% of the working or mineral interest in order to statutorily pool our applicable interest may make it much more difficult for us to develop such interests, which could have a material adverse effect on our business, financial condition, and results of operations.

In some cases, we do not own more than 45% working interest or mineral interest in a prospective area of development, which is now required to statutorily pool our applicable working or mineral interests. In such cases, unless we can obtain the consent of more than 45% of all applicable working or mineral interest owners (who can be located through reasonable diligence) to pursue statutory pooling, or achieve a voluntary pooling agreement with 100% of the applicable interest owners, we may be prohibited from developing the resources in that area or having them be developed by other operators.

We have limited control over activities on properties in which we own an interest but we do not operate, which could reduce our production and revenues.

We do not operate all of the properties in which we have an interest. We own significant non-operated working interest area within the Greater Wattenberg Area and DJ Basin which is not currently within our operated development plan. As a result, we may have a limited ability to exercise influence over normal operating procedures, expenditures, timing or future development of underlying properties and their associated costs. For all of the properties that are operated by others, we are dependent on their decision-making with respect to day-to-day operations over which we have little control. The failure of an operator of wells in which we have an interest to adequately perform operations, or an operator's breach of applicable agreements, could reduce production and revenues we receive from that well. The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including the timing and amount of capital expenditures, the available expertise and financial resources, the inclusion of other participants, and the use of technology. Our lack of control over non-operated properties also makes it more difficult for us to forecast capital expenditures, revenues, production, liability, and other related matters.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 20% of our total proved reserves were classified as proved undeveloped as of December 31, 2021. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate or that may be available to us. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

Our management has identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These potential drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including uncertainty in the level of reserves, the availability of capital to us and other participants, seasonal conditions, regulatory approvals, activist intervention, oil, natural gas and NGL prices, availability of permits, costs, and well performance. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking, and we may therefore be required to downgrade to probable or possible categories any proved undeveloped reserves that are not developed within this five-year time frame. These limitations may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

Drilling locations that we decide to drill may not yield oil or natural gas in commercially viable quantities.

We describe some of our drilling locations and our plans to explore those drilling locations in this Annual Report on Form 10-K. Our drilling locations are in various stages of evaluation, ranging from a location that is ready to drill to a location that will require substantial additional evaluation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. Prior to drilling, the use of 2-D and 3-D seismic technologies, various other technologies, and the study of producing fields in the same area will still not enable us to know conclusively whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. In addition, the use of 2-D and 3-D seismic data and other technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur greater drilling and testing expenses as a result of such expenditures which may result in a reduction in our returns or increase our losses. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. If we drill any dry holes in our current and future drilling locations, our profitability and the value of our properties will likely be reduced. We cannot assure you that the analogies we draw 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 other operators may not be indicative of future or long-term production rates. In sum, the cost of drilling, completing, and operating any well is often uncertain, and new wells may not be productive.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

The terms of our oil and gas leases often stipulate that the lease will terminate if not held by production, rentals, or otherwise some form of an extension payment to extend the term of the lease. As of December 31, 2021, approximately 67,300 net acres of our properties were not held by production. For these properties, if production in paying quantities is not established on units containing leases during the next year, then approximately 26,900 net acres will expire in 2022, approximately 12,200 net acres will expire in 2023, and approximately 28,200 net acres will expire in 2024 and thereafter. While some expiring leases may contain predetermined extension payments, other expiring leases will require us to negotiate new leases at the time of lease expiration. Further, existing leases which are currently held by production may unexpectedly encounter operational, political, regulatory, or litigation challenges which could result in their termination. It is possible that market conditions at the time of negotiation could require us to agree to new leases on less favorable terms to us than the terms of the expired leases or cause us to lose the leases entirely. If our leases expire, we will lose our right to develop the related properties.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition, and results of operations.

In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our current proved reserves will decline as reserves are produced and, therefore, our level of production and cash flows will be affected adversely unless we conduct successful exploration and development activities or acquire properties containing proved reserves. Thus, our future oil and natural gas production and, therefore, our cash flow and income are highly dependent upon our level of success in finding, acquiring, and/or developing additional reserves. However, we cannot assure you that our future acquisition, development, and exploration activities will result in any specific amount of additional proved reserves or that we will be able to drill productive wells at acceptable costs.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks, including those related to our hydraulic fracturing operations.

Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including, but not limited to, the possibility of:

- environmental hazards, such as spills, uncontrollable flows of oil, natural gas, brine, well fluids, natural gas, hazardous air pollutants, or other pollution into the environment, including soil, surface water, groundwater, and shoreline contamination;
- unpermitted releases of natural gas and hazardous air pollutants or other substances into the atmosphere at our oil and gas facilities;
- hazards resulting from the presence of hydrogen sulfide (H_2S) or other contaminants in natural gas and oil we produce;
- abnormally pressured formations resulting in well blowouts, fires, or explosions;
- mechanical difficulties, such as stuck down-hole tools or casing collapse;
- cratering (catastrophic failure);
- downhole communication leading to migration of contaminants;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources, and equipment;
- pollution and other environmental and natural resource damages;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

The presence of H_2S, a toxic, flammable, and colorless gas, is a common risk in the oil and gas industry and may be present in small amounts for brief periods from time to time at our well and facility locations. In addition, our operations in Colorado are susceptible to damage from natural disasters, such as flooding, wildfires, tornadoes, and other natural phenomena and weather conditions, including extreme temperatures, which involve increased risks of personal injury, property damage, and marketing interruptions. The occurrence of one of these operating hazards may result in injury, loss of life, suspension of operations, environmental damage and remediation liability, and/or governmental investigations and penalties. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration and development, or could result in a loss of our properties.

As is customary in the oil and gas industry, we maintain insurance against some, but not all, of these potential risks and losses. Although we believe the coverage and amounts of insurance that we carry are consistent with industry practice, we do not have insurance protection against all risks that we face, because we choose not to insure certain risks, insurance is not available at a level that balances the costs of insurance and our desired rates of return, or actual losses exceed coverage limits. Insurance costs will likely continue to increase, which could result in our determination to decrease coverage and retain more risk to mitigate those cost increases. In addition, pollution and environmental risks generally are not fully insurable. If we incur substantial liability, and the damages are not covered by insurance or are in excess of policy limits, then our business, results of operations, and financial condition may be materially adversely affected.

Because hydraulic fracturing activities are integral to our operations, they are covered by our insurance against claims made for bodily injury, property damage, and clean-up costs stemming from a sudden and accidental pollution event. However, we may not have coverage if the operator is unaware of the pollution event and unable to report the “occurrence” to the insurance company within the required time frame. We also do not have coverage for gradual, long-term pollution events, including climate change.

Under certain circumstances, we have agreed to indemnify third parties against losses resulting from our operations. Pursuant to our surface leases, we typically indemnify the surface owner for clean-up and remediation of the site. As owner and operator of oil and gas wells and associated gathering systems and pipelines, we typically indemnify the drilling contractor for pollution emanating from the well, while the contractor indemnifies us against pollution emanating from its equipment.

We are subject to health, safety, and environmental laws and regulations that may expose us to significant costs and liabilities.

We are subject to stringent and complex federal, state, and local laws and regulations governing health and safety aspects of our operations, the discharge of materials into the environment, noise emittance, light emittance, and the general protection of public health, safety, welfare, the environment, and wildlife. These laws and regulations may impose on our operations numerous requirements, including the obligation to obtain a permit before conducting drilling or underground injection activities; restrictions on the types, quantities, and concentration of materials that may be released into the environment; limitations or prohibitions of drilling or completion activities; the application of specific health and safety criteria to protect the public or workers; and the responsibility for cleaning up pollution resulting from operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties; the imposition of investigatory or remedial obligations; the issuance of injunctions limiting or preventing some or all of our operations; delays in granting permits; or even the cancellation of leases and/or permits.

There is an inherent risk of incurring significant environmental costs and liabilities in our operations, some of which may be material, due to our handling of petroleum hydrocarbons and wastes, our emissions into air, water and the environment, the underground injection or other disposal of our wastes, the use and disposition of hydraulic fracturing fluids, and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we may be liable for the full cost of removing or remediating contamination, regardless of whether we were at fault, and even when multiple parties contributed to the release and the contaminants were released in compliance with all applicable laws then in effect. In addition, accidental spills or releases on or off our properties may expose us to significant liabilities that could have a material adverse effect on our financial condition or results of operations. Aside from government agencies, the owners of properties where our wells are located, the owners or operators of facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal or otherwise come to be located, and other private parties may be able to sue us to enforce compliance with environmental laws and regulations, collect penalties for violations, or obtain damages for any related personal injury, or damage and property damage, and certain trustees may seek natural resource damages. Some sites we operate are located near current or former third-party oil and natural gas operations or facilities, and there is a risk that historic contamination has migrated from those sites to ours. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly requirements could require us to make significant expenditures to attain and maintain compliance or may otherwise have a material adverse effect on our own results of operations, competitive position, or financial condition. We may not be able to recover some or any of these costs from insurance.

Evolving environmental legislation or regulatory initiatives, including those related to hydraulic fracturing, could result in increased costs and additional operating restrictions or delays.

We are subject to extensive federal, state, and local laws and regulations concerning health, safety, and environmental protection. Governmental authorities frequently add to those requirements, and both oil and gas development generally, and hydraulic fracturing specifically, are receiving increasing legislative and regulatory attention. For example, during 2020, the COGCC revised its regulations on a range of topics including facility siting, development approvals, cumulative impacts, asset transfers, pollution standards, hearings and variances, groundwater monitoring, underground injection control and enhanced recovery wells, venting and flaring restrictions, spill reporting, cleanup responsibility, and wildlife protection. And legislation passed in 2019 requires the COGCC to assess and potentially revise its financial assurance requirements for oil and gas development. Financial assurance rulemaking will be completed in early 2022, which will impact fees required for surety bonding and include comprehensive language that will address the transfer of wells and plugging and abandonment obligations. Our operations utilize hydraulic fracturing, an important and commonly used process in the completion of oil and natural gas wells in low-permeability formations. Hydraulic fracturing involves the injection of water, proppant, and chemicals under pressure into rock formations to stimulate hydrocarbon production.

Some activists have attempted to link hydraulic fracturing to various environmental problems, including potential adverse effects on drinking water supplies, migration of methane and other hydrocarbons into groundwater, increased seismic activity, nuisance claims, and human health effects. The federal government has periodically studied the environmental risks associated with hydraulic fracturing and evaluated whether to adopt, and in some cases has adopted, additional regulatory requirements.

In some instances, certain state and local governments are adopting new requirements on hydraulic fracturing and other oil and gas operations. Some counties in Colorado, for instance, have amended their land use regulations to impose new siting and other requirements on oil and gas development, while other local governments have entered memoranda of agreement with oil and gas producers to accomplish the same or similar objectives. Under current Colorado law, local governments can regulate both facility siting and the surface impacts associated with oil and gas development, and local government regulations may be more protective or stricter than State requirements. In addition, voters in Colorado have proposed or advanced ballot initiatives restricting or banning oil and gas development in Colorado. Because our operations and reserves are solely located in Colorado, the risks we face with respect to such ballot initiatives are greater than other companies with more geographically diverse operations.

The adoption of future federal, state, or local laws or implementing regulations imposing new environmental, operational, and/or financial assurance obligations on, or otherwise limiting, our operations could make it more difficult, more expensive, and/or impossible to complete oil and natural gas wells, increase our costs of compliance operations, delay or prevent the development of certain resources (including especially shale formations that are not commercial without the use of hydraulic fracturing), or alter the demand for and consumption of our products. We cannot assure that any such outcome would not be material, and any such outcome could have a material adverse impact on our cash flows and results of operations.

Climate change laws and regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas that we produce, while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

There is a broad consensus of scientific opinion that human-caused (anthropogenic) emissions of greenhouse gases ("GHGs") are linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and the demand for and consumption of our products (due to potential changes in both costs and weather patterns).

The EPA also adopted regulations requiring the reporting of GHG emissions from specific categories of higher GHG emitting sources in the United States, including certain oil and natural gas production facilities, which include certain of our operations. Information in such reporting may form the basis for further GHG regulation. Further, the EPA has continued with its comprehensive strategy for further reducing methane emissions from oil and gas operations, with a final rule being issued in May 2016 as part of the Subpart OOOOa NSPS rules discussed above. The EPA's GHG rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities.

In the meantime, many states already have taken such measures, which have included renewable energy standards, development of GHG emission inventories or cap and trade programs, and the adoption of ambitious climate action targets in Colorado under HB 19-1261. Cap and trade programs typically work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of available allowances reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. Such a program has been proposed by an environmental group to the Colorado AQCC in a petition filed on December 23, 2020. The AQCC will consider action on that petition later in 2021.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions and vapor control systems, to acquire emissions allowances, or to comply with new regulatory or reporting requirements. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition, and results of operations. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for the oil and natural gas we produce. In addition, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds, and other sources of capital restricting or eliminating their investment in oil and natural gas activities.

The negative shift in investor sentiment of the oil and gas industry could have adverse effects on our ability to raise debt and equity capital and on our operations.

Certain segments of the investor community have developed negative sentiment towards investing in our industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. In addition, some investors, including investment advisors and certain sovereign wealth funds, pension funds, university endowments and family foundations, have stated policies to disinvest in the oil and gas sector based on their social and environmental considerations. Certain other stakeholders have also pressured commercial and investment banks to stop financing oil and gas production and related infrastructure projects. Such developments, including environmental activism and initiatives aimed at limiting climate change and reducing air pollution, could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding for potential development projects, impacting our future financial results.

Additionally, negative public perception regarding us and/or our industry may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Additionally, environmental groups, landowners, local groups and other advocates may oppose our operations through organized protests, attempts to block or sabotage our operations or those of our midstream transportation providers, intervene in regulatory or administrative proceedings involving our assets or those of our midstream transportation providers, or file lawsuits or other actions designed to prevent, disrupt or delay the development or operation of our assets and business or those of our midstream transportation providers. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we require to conduct our operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct our business. Recently, activists concerned about the potential effects of climate change have directed their attention towards sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in energy-related activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities.

We are exposed to credit risks of our hedging counterparties, third parties participating in our wells, and our customers.

Our principal exposures to credit risk are through receivables resulting from commodity price derivatives instruments, joint interest billings, and other components of $69.8 million at December 31, 2021, and the sale of our oil, natural gas, and NGLs production of $362.3 million in receivables at December 31, 2021, which we market to energy marketing companies, refineries, and affiliates.

Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We can do very little to choose who participates in our wells.

We are also subject to credit risk due to concentration of our oil, natural gas, and NGLs receivables with significant customers. This concentration of customers may impact our overall credit risk since these entities may be similarly affected by changes in economic, political, and other conditions.

We are exposed to credit risk in the event of default of our counterparty, principally with respect to hedging agreements, but also with respect to insurance contracts and bank lending commitments. We do not require most of our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us.

Current or proposed financial legislation and rulemaking could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate, and other risks associated with our business.

The Dodd-Frank Act establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act also establishes margin requirements and certain transaction clearing and trade execution requirements. The Dodd-Frank Act may require us to comply with margin requirements in our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivative as a result of the Dodd-Frank Act and regulations, our results of operations may be more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

We may be involved in legal cases that may result in substantial liabilities.

Like many oil and gas companies, we are involved in various legal and other cases, such as title, royalty or contractual disputes, regulatory compliance matters, and personal injury or property damage matters, in the ordinary course of our business. Such legal cases are inherently uncertain, and their results cannot be predicted. Regardless of the outcome, such cases could have an adverse impact on us because of legal costs, diversion of management and other personnel, and other factors. In addition, it is possible that a resolution of one or more such cases could result in liability, penalties, or sanctions, as well as judgments, consent decrees, or orders requiring a change in our business practices, which could materially and adversely affect our business, operating results, and financial condition. Accruals for such liability, penalties, or sanctions may be insufficient. Judgments and estimates to determine accruals or range of losses related to legal and other cases could change from one period to the next, and such changes could be material.

We are subject to federal, state, and local taxes and may become subject to new taxes, and certain federal income tax deductions and state income tax deductions and exemptions currently available with respect to oil and gas exploration and development may be eliminated or reduced as a result of future legislation.

The federal, state, and local governments in the areas in which we operate (i) impose taxes on the oil and natural gas products we sell, and (ii) for many of our wells, impose sales and use taxes on significant portions of our drilling and operating costs. Many states have raised state taxes on energy sources or state taxes associated with the extraction of hydrocarbons, and additional increases, unexpectedly may occur. In addition, there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals.

There have been proposals for legislative changes that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. Any such changes in U.S. federal income tax law could eliminate or defer certain tax deductions within the industry that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition, results of operations, and cash flow.

In Colorado, there may be proposals for legislative changes that, if enacted into law, could substantially increase our severance tax and ad valorem tax effective rates. Such changes may include, but are not limited to, (i) the reduction or elimination of the credit against severance tax based on the property tax we pay; (ii) the reduction or elimination of certain exemptions impacting severance tax liability; and (iii) increased severance tax rates. Any such changes to Colorado’s ad valorem and severance tax laws could negatively affect our financial condition, results of operations, and cash flow.

Changes to federal tax deductions, as well as any changes to or the imposition of new state or local taxes (including production, severance, or similar taxes) could negatively affect our financial condition, results of operations, and cash flow.

The HighPoint, Extraction, and Crestone Peak Mergers triggered a limitation on the utilization of our historic U.S. net operating loss carryforwards (“NOLs”), HighPoint's NOLs, Extraction’s NOLs, and Crestone Peak’s NOLs.

Our ability to utilize NOLs (including NOLs of HighPoint, Extraction, and Crestone Peak) to reduce future taxable income following the HighPoint, Extraction, and Crestone Peak Mergers depends on many factors, including our future income, which cannot be assured. Section 382 of the Code generally imposes an annual limitation upon the occurrence of an “ownership change” resulting from issuances of a company’s stock or the sale or exchange of such company’s stock by certain stockholders if, as a result, there is an aggregate change of more than 50% in the beneficial ownership of such company’s stock by such stockholders within a rolling three-year period. The limitation with respect to such loss carryforwards generally would be equal to (i) the fair market value of the company’s equity immediately prior to the ownership change multiplied by (ii) a percentage approximately equivalent to the yield on long-term tax-exempt bonds during the month in which the ownership change occurs. Based on the information currently available, we believe that the transactions in connection with the HighPoint, Extraction, and Crestone Peak Mergers, will result in an ownership change with respect to us, HighPoint, Extraction, and Crestone Peak, which would trigger a limitation (calculated as described above) on our ability to utilize any historic NOLs following the HighPoint, Extraction, and Crestone Peak Mergers. Extractions’ NOLs are already limited under Section 382 of the Code as a result of an ownership change that occurred in connection with Extraction’s Chapter 11 cases.

The Extraction Merger and the Crestone Peak Merger has caused increased exposure to risks regarding urban encroachment, increased activism against oil and gas exploration, urban and suburban density, and residential expansion in the areas in which we operate.

The merger of our company with Extraction and Crestone Peak has resulted in the Company holding a greater asset base within an urban and suburban corridor within Colorado. As a result, the Company faces increased risk to urban encroachment, evolving environmental legislation or regulatory initiatives, health, safety, and environmental regulation, political activism against oil and gas exploration, climate change laws, litigation, taxes, enforcement, and siting issues that are identified within these risk factors. As a result of this increased risk, the Company may face difficulties securing permits, executing on our production target, meeting operations benchmarks, and other general risks to the Company that are identified herein.

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

The oil and gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, processing, and distribution activities. For example, we depend on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, conduct reservoir modeling and reserves estimation, and process and record financial and operating data. Pipelines, refineries, power stations, and distribution points for both fuels and electricity are becoming more interconnected by computer systems. We also depend on digital technology, including information systems and related infrastructure, as well as cloud applications and services, to process and record financial and operating data, communicate with our employees and business parties, analyze seismic and drilling information, estimate quantities of oil and gas reserves, as well as other activities related to our business. We also collect and store sensitive data in the ordinary course of our business, including personally identifiable information of our employees as well as our proprietary business information and that of our customers, suppliers, investors and other stakeholders. Our business partners, including vendors, service providers, purchasers of our production, and financial institutions, are also dependent on digital technology. The secure processing, maintenance and transmission of information is critical to our operations, and we monitor our key information technology systems in an effort to detect and prevent cyber-attacks, security breaches or unauthorized access. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased and are becoming increasingly sophisticated. Despite our security measures, our technologies, systems, networks, and those of our vendors, suppliers, and other business partners may become the target of cyber-attacks 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, weaknesses in the cyber security of our vendors, suppliers, and other business partners could facilitate an attack on our technologies, systems, and networks. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Given the politically sensitive nature of hydraulic fracturing and the controversy generated by its opponents, our technologies, systems, and networks may be of particular interest to certain groups with political agendas, which may seek to launch cyber-attacks as a method of promoting their message. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient.

As cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber-attacks. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our personnel, information, facilities and infrastructure may result in increased capital and operating costs. A cyber-attack or security breach could result in liability under data privacy laws, regulatory penalties, damage to our reputation or loss of confidence in us, or additional costs for remediation and modification or enhancement of our information systems to prevent future occurrences, all of which could have a material and adverse effect on our business, financial condition or results of operations. To date we have not experienced any material losses relating to cyber-attacks; however, there can be no assurance that we will not suffer such losses in the future. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

Risks Related to our Common Stock

The market price for our common stock following the Extraction Merger and the Crestone Peak Merger may be affected by factors different from those that historically have affected or currently affect our common stock.

Our financial position following the Extraction Merger and the Crestone Peak Merger is different from our financial position before the Extraction Merger and the Crestone Peak Merger, and the results of operations of the combined company may be affected by factors that are different from those currently affecting the results of our operations. Accordingly, the market price and performance of our common stock is likely to be different from the performance of our common stock in the absence of the Extraction Merger and the Crestone Peak Merger.

The Kimmeridge Fund and CPPIB Crestone Peak Resources Canada Inc., a Canadian corporation (the "Crestone Peak Stockholder") became significant holders of our Common Stock following completion of the Extraction Merger and the Crestone Peak Merger.

Upon completion of the Extraction Merger and the Crestone Peak Merger, a private investment fund managed by Kimmeridge Energy Management Company, LLC, which owns shares through a subsidiary, Kimmeridge Chelsea, LLC, (the "Kimmeridge Fund") owns approximately 14% of our Common Stock, representing approximately 14% of our combined voting power, and the Crestone Peak Stockholder owns approximately 25% of our Common Stock, representing approximately 25% of our combined voting power. In addition, upon completion of the Extraction Merger, Mr. Benjamin Dell, independent chairman of the Extraction board and a Manager of the Kimmeridge Fund, became chairman of the Board of Directors of the

Company; and, effective January 31, 2022, he became the Interim Chief Executive Officer. As a result, we believe that the Kimmeridge Fund and the Crestone Peak Stockholder may or will have some ability to influence our management and affairs. Further, the existence of a new significant stockholder may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may view as being in their best interests or in our best interests.

In the event that the Kimmeridge Fund or the Crestone Peak Stockholder continue to be the owner of a significant amount of our Common Stock, the prospect that they may be able to influence matters requiring stockholder approval may continue. In any of these matters, the interests of the Kimmeridge Fund or the Crestone Peak Stockholder and of our other stockholders may differ or conflict. Moreover, in the event that the Kimmeridge Fund or the Crestone Peak Stockholder continue to be the owner of a significant concentration of our Common Stock, such an ownership stake may also adversely affect the trading price of our Common Stock to the extent investors perceive a disadvantage in owning stock of a company with a significant stockholder.

We have experienced recent volatility in the market price and trading volume of our common stock and may continue to do so in the future.

The trading price of shares of our common stock has fluctuated widely and in the future may be subject to similar fluctuations. As an example, during the 2021 calendar year, the sales price of our common stock ranged from a low of $19.39 per share to a high of $59.65 per share. The trading price of our common stock may be affected by a number of factors, including the volatility of oil, natural gas, and NGL prices, our operating results, changes in our earnings estimates, additions or departures of key personnel, our financial condition and liquidity, drilling activities, legislative and regulatory changes, general conditions in the oil and natural gas exploration and development industry, general economic conditions, and general conditions in the securities markets. In particular, a significant or extended decline in oil, natural gas, and NGL prices could have a material adverse effect our sales price of our common stock. Other risks described in this annual report could also materially and adversely affect our share price.

Although our common stock is listed on the New York Stock Exchange, we cannot assure you that an active public market will continue for our common stock or that we will be able to continue to meet the listing requirements of the NYSE. If an active public market for our common stock does not continue, the trading price and liquidity of our common stock will be materially and adversely affected. If there is a thin trading market or "float" for our stock, the market price for our common stock may fluctuate significantly more than the stock market as a whole. Without a large float, our common stock would be less liquid than the stock of companies with broader public ownership and, as a result, the trading prices of our common stock may be more volatile. In addition, in the absence of an active public trading market, investors may be unable to liquidate their investment in us.

Our ability to pay dividends to our stockholders is restricted by applicable laws and regulations and requirements under certain of our debt agreements, including the Credit Facility and the indentures governing our senior notes.

Holders of our common stock are only entitled to receive such cash dividends as our Board, in its sole discretion, may declare out of funds legally available for such payments. In May 2021, we announced the initiation of an annual cash dividend and, in March 2022, the Board approved the initiation of a quarterly variable cash dividend, assuming pro forma compliance with certain leverage targets. The decision to pay any future dividends is solely within the discretion of, and subject to approval by, our Board. Our Board's determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon, among other things, our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law and other factors that our Board deems relevant at the time of such determination. We cannot assure you, however, that we will pay dividends in the future in the current amounts or at all. Our Board may change the timing and amount of any future dividend payments or eliminate the payment of future dividends to our common stockholders at its discretion, without notice to our stockholders. Our ability to declare and pay dividends to our stockholders is subject to certain laws, regulations, and policies, including minimum capital requirements and, as a Delaware corporation, we are subject to certain restrictions on dividends under the Delaware General Corporation Law (the "DGCL"). Under the DGCL, our Board may not authorize payment of a dividend unless it is either paid out of our surplus, as calculated in accordance with the DGCL, or if we do not have a surplus, it is paid out of our net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. In addition, our ability to pay cash dividends to our stockholders may be limited by covenants in any debt agreements that we are currently a party to, including the Credit Facility and the indentures governing our senior notes, or may enter into in the future. As a consequence of these various limitations and restrictions, we may not be able to make, or may have to reduce or eliminate at any time, the payment of dividends on our common stock. If as a result, we are unable to pay dividends, investors may be forced to rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Any change in the level of our dividends or the suspension of the payment thereof could have a material adverse effect on the market price of our common stock.

Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, even if such acquisition or merger may be in our stockholders' best interests.

Our certificate of incorporation authorizes our Board of Directors to issue preferred stock without stockholder approval. If our Board elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- advance notice provisions for stockholder proposals and nominations for elections to the Board to be acted upon at meetings of stockholders; and
- limitations on the ability of our stockholders to call special meetings or act by written consent.

Delaware law prohibits us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our Board.

Our certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, or other employees.

Our certificate of incorporation provides that, unless we consent in writing to the selection of an alternative forum, the sole and exclusive forum shall be the Court of Chancery of the State of Delaware for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any director, officer, employee or agent of ours to us or to our stockholders, (iii) any action asserting a claim against us arising pursuant to any provision of the DGCL, our certificate of incorporation or our bylaws (or any action to interpret, apply or enforce any provision thereof), or (iv) any action asserting a claim against us governed by the internal affairs doctrine, in each such case subject to said court of chancery having personal jurisdiction over the indispensable parties named as defendants therein.

Our exclusive forum provision is not intended to apply to claims arising under the Securities Act or the Exchange Act. To the extent the provision could be construed to apply to such claims, there is uncertainty as to whether a court would enforce the forum selection provision with respect to such claims, and in any event, our stockholders would not be deemed to have waived our compliance with federal securities laws and the rules and regulations thereunder. Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock is deemed to have received notice of and consented to the foregoing forum selection provision. This provision may limit our stockholders' ability to bring a claim in a judicial forum that they find favorable for disputes with us or our directors, officers, or other employees, which may discourage such lawsuits. Alternatively, if a court were to find this choice of forum provision 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, prospects, or results of operations.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

The information required by Item 2. is contained in Item 1. *Business* and is incorporated herein by reference.

Item 3. ***Legal Proceedings.***

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of business. Like other gas and oil producers and marketers, our operations are subject to extensive and rapidly changing federal and state environmental, health, and safety and other laws and regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. As of the date of this filing, there is active and ongoing litigation between Boulder County and Extraction which could prevent oil and gas operations for the development minerals contained within Boulder County, Colorado.

Boulder County initiated suit in District Court for Boulder County, Colorado in case no. 2018CV030925 on September 25, 2018, Extraction prevailed before the district court on all issues in an order dated August 29, 2019. The district court's order was appealed, has been fully briefed on appeal, and was argued before the Colorado Court of Appeals on December 14, 2021 - *Board of County Commissioners of Boulder County v. 8 North and Extraction Oil & Gas*, Case No. 2019CA001896 *(Colorado Court of Appeals)*. On March 3, 2022, the Colorado Court of Appeals issued a unanimous opinion rejecting Boulder County's claims. We await whether Boulder will petition the Colorado Supreme Court for certiorari.

This action is primarily a contract case, where the relevant contracts are the conservation easement ("CE") over the Blue Paintbrush location, Extraction's Surface Use Agreement ("SUA") for the Blue Paintbrush location, and the leases that Boulder owns within the Blue Paintbrush drilling and spacing unit. Boulder seeks invalidation of these leases in the litigation.

Boulder argues that the lease underlying the CE only authorizes the extraction of minerals underneath the CE Property. Boulder takes issue with the planned 32 wells for the location and argues that only the number of wells necessary to extract the minerals underlying the CE property should be allowed. Boulder also argues that Extraction induced a breach of the CE by contracting with the CE property owner for the SUA. Boulder argues that the terms of the SUA violate the CE because the SUA allows for development in excess of that allowed under the underlying lease. Boulder's argument is based on its assertion that the lease underlying the CE property only allows for the extraction of minerals underneath the CE property and ignores that the lease underlying the CE property explicitly allows for pooling and unitization.

Boulder's remaining claims assert that Extraction breached the terms of leases Boulder owns in the drilling and spacing unit by establishing the Blue Paintbrush drilling and spacing unit. Specifically, Boulder's leases within the Blue Paintbrush drilling and spacing unit have a clause that states that a unit must be the "minimum size tract on which a well may be drilled under the laws, rules, or regulations in force at the time of such pooling or unitization." Boulder argues that no drilling and spacing unit including acreage covered by these leases can be greater than 80 acres because COGCC Order 407 established 80-acre drilling and spacing units for the Codell and COGCC Order 407-87 established 80-acre drilling and spacing unit for the Niobrara. In making this argument, Boulder fails to acknowledge that COGCC Rule 318A.l., provides that "…this rule supersedes all prior Commission drilling and spacing orders affecting well location and density requirements of GWA wells. Where the Commission has issued a specific order limiting the number of horizontal wells in a drilling and spacing unit, the well density in such units shall be governed by that order."

An outcome adverse to Extraction, could lead to expiration of our leases in the Blue Paint Brush drilling and spacing unit and impact future, planned locations that include Boulder minerals, result in a decline of our oil and natural gas reserves, or anticipated production volumes.

Item 4. ***Mine Safety Disclosures.***

Not applicable.

PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.***

Market for Registrant's Common Equity. Our common stock is listed on the NYSE under the symbol "CIVI".

Holders. As of March 4, 2022, there were approximately 143 registered holders of our common stock.

Dividend Policy. On May 3, 2021, we announced the initiation of an annual cash dividend in the amount of $1.40 per share of our common stock payable quarterly, which began on July 14, 2021. Beginning with the fourth quarter of 2021, the annual cash dividend was increased to $1.85 per share of our common stock, and, in March 2022, the Board approved the initiation of a quarterly variable cash dividend, assuming pro forma compliance with certain leverage targets. The decision to pay any future dividends is solely within the discretion of, and subject to approval by, our board of directors. Our board of directors' determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law and other factors that the board deems relevant at the time of such determination. Additionally, covenants contained in our Credit Facility and the indentures governing our senior notes restrict the payment of cash dividends on our common stock, as discussed further in *Part II, Item 7, Liquidity and Capital Resources*.

Issuer Purchases of Equity Securities. The following table contains information about our acquisition of equity securities during the three months ended December 31, 2021.

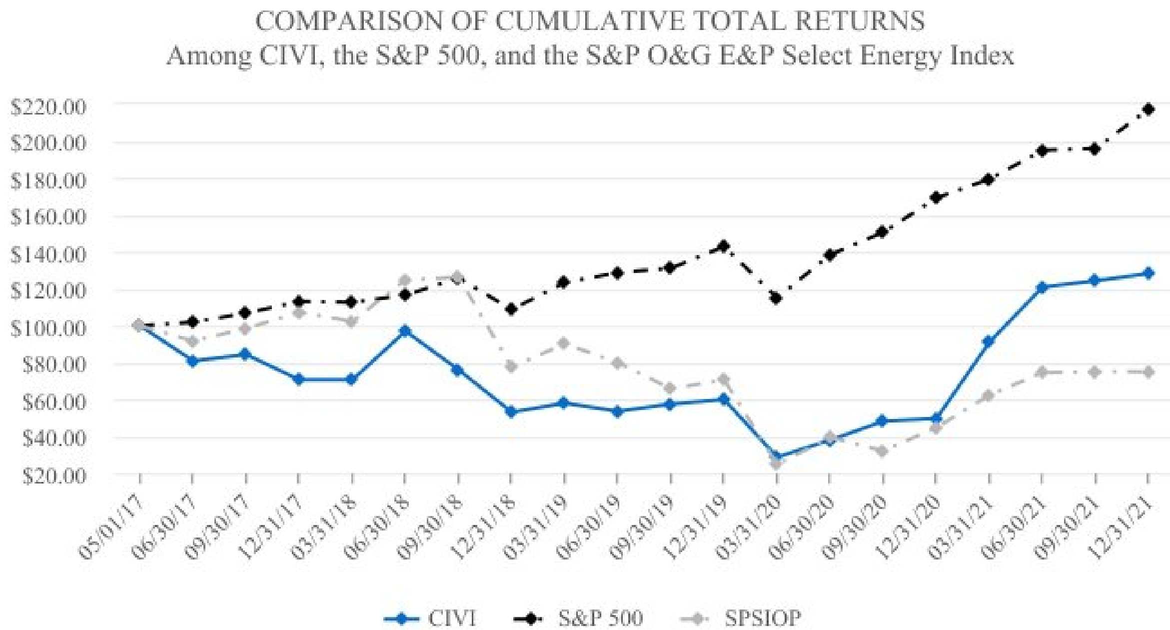
	Total Number of Shares Purchased[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Be Purchased Under Plans or Programs
October 1, 2021 - October 31, 2021	157	$ 51.85	—	—
November 1, 2021 - November 30, 2021	5,227	$ 56.17	—	—
December 1, 2021 - December 31, 2021	48,263	$ 54.47	—	—
Total	53,647	$ 54.99	—	—

(1) Represent shares that employees surrendered back to us that equaled in value the amount of taxes needed for payroll tax withholding obligations upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced plan or program to repurchase shares of our common stock, nor do we have a publicly announced plan or program to repurchase shares of our common stock.

Sale of Unregistered Securities. We had no sales of unregistered securities during the year ended December 31, 2021.

Stock Performance Graph. The following performance graph shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to liabilities under that section and shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

The following graph compares the cumulative total stockholder return for the Company's common stock, the Standard and Poor's 500 Stock Index (the "S&P 500 Index") and the Standard and Poor's 500 Oil & Gas Exploration & Production Index ("S&P O&G E&P Index"). The measurement points in the graph below are May 1, 2017 (the first trading day of our common stock on the NYSE upon emergence from bankruptcy) and each fiscal quarter thereafter through December 31, 2021. The graph assumes that $100 was invested on May 1, 2017 in each of the common stock of the Company, the S&P 500 Index, and the S&P O&G E&P Index and assumes reinvestment of any dividends. The stock price performance on the following graph is not necessarily indicative of future stock price performance.



Item 6. *[Reserved].*

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

The following discussion and analysis contains forward-looking statements, including, without limitation, statements relating to our plans, strategies, objectives, expectations, intentions, and resources. Such forward-looking statements should be read in conjunction with our disclosures under "Item 1A. Risk Factors" of this Form 10-K.

This section of this Form 10-K generally discusses 2021 and 2020 results and year-to-year comparisons between 2021 and 2020. Discussions of 2019 items and year-to-year comparisons between 2020 and 2019 that are not included in this Form 10-K can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of Civitas' Annual Report on Form 10-K for the fiscal year ended December 31, 2020.

Executive Summary

We are an independent Denver-based exploration and production company focused on the acquisition, development, and production of oil and associated liquids-rich natural gas in the Rocky Mountain region, primarily in the Wattenberg Field of the DJ Basin of Colorado. We believe our acreage in the DJ Basin has been significantly delineated by our own drilling success and by the success of offset operators, providing confidence that our inventory is repeatable and will continue to generate economic returns. The majority of our revenues are generated through the sale of oil, natural gas, and natural gas liquids production.

The Company's primary objective is to maximize shareholder returns by responsibly developing our oil and natural gas resources. Key aspects of our strategy include multi-well pad development across our leasehold, continuous safety improvement, strict adherence to health and safety regulations, environmental stewardship, disciplined approach to acquisitions and divestitures and capital allocation, and prudent risk management.

Financial and Operating Results

Our 2021 financial and operational results include:

- Crude oil equivalent sales volumes increased 121% for the year ended December 31, 2021 when compared to the same period during 2020 primarily due to the HighPoint, Extraction, and Crestone Peak mergers;
- General and administrative expense per Boe decreased by 16% for the year ended December 31, 2021 when compared to the same period during 2020;
- Lease operating expense per Boe increased by 8% per Boe for the year ended December 31, 2021 when compared to the same period during 2020;
- Borrowings under our Credit Facility were reduced by $155.0 million to zero during the year ended December 31, 2021 from the $155.0 million borrowed at the closing of the HighPoint Merger to pay down the HighPoint credit facility;
- Total liquidity was $1.0 billion at December 31, 2021, consisting of cash on hand plus funds available under our Credit Facility, after giving effect to an aggregate of $21.7 million of undrawn letters of credit. Please refer to *Liquidity and Capital Resources* below for additional discussion;
- Cash dividends of $60.8 million, or $1.16 per share, declared and paid during the year ended December 31, 2021;
- Cash flows provided by operating activities for the year ended December 31, 2021 were $274.6 million, as compared to cash flows provided by operating activities of $158.8 million during the year ended December 31, 2020. Please refer to *Liquidity and Capital Resources* below for additional discussion;
- Proved reserves of 397.7 MMBoe as of December 31, 2021 increased by 236% when compared to proved reserves as of December 31, 2020; and
- Capital expenditures, inclusive of accruals, were $299.4 million during the year ended December 31, 2021, which was within guidance.

Midstream Assets

The Company's midstream assets provide reliable gathering, treating, and storage for the Company’s operated production while reducing facility site footprints, leading to more cost-efficient operations and reduced emissions and surface disturbance per Boe produced. Additionally, this infrastructure helps ensure that the Company's production is not constrained by any single midstream service provider.

RMI, together with adjacent gathering assets acquired from HighPoint, serves the Company’s eastern acreage position with multiple interconnects to four different natural gas processors. Significant cost and operational synergies have been realized with the combination of RMI and HighPoint midstream assets. Additionally, in 2019, the Company installed a new oil gathering line to Riverside Terminal (on the Grand Mesa Pipeline), which resulted in a corresponding $1.25 to $1.50 per barrel reduction to our oil differentials for barrels transported on such gathering line. The Company completed an additional oil interconnect in September 2021, thus providing additional outlets that provide flow assurance and minimize differentials. The total value of reduced oil differentials during the years ended December 31, 2021 and 2020 was approximately $5.0 million and $6.2 million, respectively

As a result of the Crestone Peak Merger, the Company acquired a gas gathering system that serves the Company's southern acreage position and an oil gathering system that serves a portion of the Company's western acreage. The gas gathering system ensures reliable, low-pressure service at the wellhead. The capacity of this system is in the process of being expanded with the addition of another compressor station. The oil gathering system gathers, treats, and stores oil and water from multiple nearby producing pads and subsequently delivers each to downstream outlets.

The net book value of the Company's midstream assets was $276.1 million as of December 31, 2021.

Current Events and Outlook

The worldwide outbreak of COVID-19, the uncertainty regarding the impact of COVID-19, and various governmental actions taken to mitigate the impact of COVID-19, resulted in an unprecedented decline in demand for oil and natural gas. At the same time, the decision by Saudi Arabia in March 2020 to drastically reduce export prices and increase oil production further increased the excess supply of oil and natural gas throughout 2020. However, during 2021, expectations surrounding the demand for oil and natural gas stimulated a rise in oil and natural gas prices.

The COVID-19 outbreak and its development into a pandemic in March 2020 also required that we take precautionary measures intended to help minimize the risk to our business, employees, customers, suppliers, and the communities in which we operate. Our operational employees are currently still able to work on site. However, we have taken various precautionary measures with respect to our operational employees such as requiring them to verify they have not experienced any symptoms consistent with COVID-19, or been in close contact with someone showing such symptoms, before reporting to the work site, quarantining any operational employees who have shown signs of COVID-19 (regardless of whether such employee has been confirmed to be infected), and imposing social distancing requirements on work sites, all in accordance with the guidelines released by the Centers for Disease Control and Prevention. We have not experienced any material operational disruptions (including disruptions from our suppliers and service providers) as a result of a COVID-19 outbreak.

On April 1, 2021, we completed the previously announced acquisition of HighPoint, and on November 1, 2021, we completed the previously announced mergers with Extraction and Crestone Peak. The Company has successfully integrated the operations, production and accounting databases derived from the HighPoint, Extraction, and Crestone Peak mergers. The go-forward Company will incorporate the best practices and processes from each legacy organization.

On January 31, 2022, we signed definitive agreements to acquire privately held DJ Basin operator Bison Oil & Gas II, LLC (“Bison”) for approximately $346 million of consideration, including the assumption of approximately $176 million in debt and other liabilities. On February 27, 2022, the Company and Bison entered into an amendment to the definitive agreements signed on January 31, 2022 to, among other things, increase the aggregate cash consideration paid to Bison from $45 million to $160 million and eliminate the previously contemplated share consideration. The transaction closed on March 1, 2022 and demonstrates Civitas’ disciplined approach to consolidation with a focus on value creation and accretion.

The Company's 2022 drilling and completion capital budget of $825 million to $950 million contemplates the closing of the Bison acquisition and running an average of 3.5 operated rigs and 3 operated crews that will drill 190 to 210 and complete 165 to 175 gross operated wells. Additionally, we intend to invest approximately $70 million to $90 million in land, midstream, and other capital activity that will support our acreage positions and overall infrastructure.

Results of Operations

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the notes thereto contained in Part II, Item 8 of this Annual Report on Form 10-K. Comparative results of operations for the period indicated are discussed below.

The following table summarizes our product revenues, sales volumes, and average sales prices for the periods indicated:

	Year Ended December 31, 2021	Year Ended December 31, 2020	Change	Percent Change
Revenues (in thousands):				
Crude oil sales[1]	$ 613,804	$ 172,787	$ 441,017	255 %
Natural gas sales[2]	141,090	20,562	120,528	586 %
Natural gas liquids sales	171,095	19,311	151,784	786 %
Product revenue	$ 925,989	$ 212,660	$ 713,329	335 %
Sales Volumes:				
Crude oil (MBbls)	9,384.6	5,019.4	4,365.2	87 %
Natural gas (MMcf)	36,763.4	14,165.7	22,597.7	160 %
Natural gas liquids (MBbls)	4,933.6	1,858.2	3,075.4	166 %
Crude oil equivalent (MBoe)[3]	20,445.4	9,238.6	11,206.8	121 %
Average Sales Prices (before derivatives)[4]:				
Crude oil (per Bbl)	$ 65.41	$ 34.42	$ 30.99	90 %
Natural gas (per Mcf)	$ 3.84	$ 1.45	$ 2.39	165 %
Natural gas liquids (per Bbl)	$ 34.68	$ 10.39	$ 24.29	234 %
Crude oil equivalent (per Boe)[3]	$ 45.29	$ 23.02	$ 22.27	97 %
Average Sales Prices (after derivatives)[4]:				
Crude oil (per Bbl)	$ 42.49	$ 44.41	$ (1.92)	(4)%
Natural gas (per Mcf)	$ 2.43	$ 1.40	$ 1.03	74 %
Natural gas liquids (per Bbl)	$ 32.84	$ 10.39	$ 22.45	216 %
Crude oil equivalent (per Boe)[3]	$ 31.80	$ 28.37	$ 3.43	12 %

(1) Crude oil sales excludes $1.0 million and $1.7 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2021 and 2020, respectively.
(2) Natural gas sales excludes $3.6 million and $3.7 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2021 and 2020, respectively.
(3) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil.
(4) Derivatives economically hedge the price we receive for oil, natural gas, and NGL. For the year ended December 31, 2021, the derivative cash settlement loss for oil, natural gas, and NGLs was $215.1 million, $51.8 million, $9.1 million, respectively. For the year ended December 31, 2020, the derivative cash settlement gain for oil was $50.1 million, and the derivative cash settlement loss for natural gas was $0.7 million. Please refer to *Part II, Item 8, Note 9 - Derivatives* for additional disclosures.

Product revenues increased by 335% to $926.0 million for the year ended December 31, 2021 compared to $212.7 million for the year ended December 31, 2020. The increase was largely due to a 121% increase in sales volumes and a $22.27, or 97%, increase in oil equivalent pricing, excluding the impact of derivatives. The increase in sales volumes is due to the HighPoint Merger that closed on April 1, 2021 and the Extraction and Crestone Peak mergers that closed on November 1, 2021. Additionally, we turned 70 gross wells to sales during the year ending December 31, 2021.

The following table summarizes our operating expenses for the periods indicated (in thousands, except per Boe amounts):

	Year Ended December 31, 2021	Year Ended December 31, 2020	Change	Percent Change
Operating Expenses:				
Lease operating expense	$ 52,391	$ 21,957	$ 30,434	139 %
Midstream operating expense	17,426	14,948	2,478	17 %
Gathering, transportation, and processing	64,507	16,932	47,575	281 %
Severance and ad valorem taxes	65,113	3,787	61,326	1619 %
Exploration	7,937	596	7,341	1232 %
Depreciation, depletion, and amortization	226,931	91,242	135,689	149 %
Abandonment and impairment of unproved properties	57,260	37,343	19,917	53 %
Unused commitments	7,692	—	7,692	100 %
Bad debt expense	607	818	(211)	(26)%
Merger transaction costs	43,555	6,676	36,879	552 %
General and administrative expense	65,132	34,936	30,196	86 %
Operating expenses	$ 608,551	$ 229,235	$ 379,316	165 %
Selected Costs ($ per Boe):				
Lease operating expense	$ 2.56	$ 2.38	$ 0.18	8 %
Midstream operating expense	0.85	1.62	(0.77)	(48)%
Gathering, transportation, and processing	3.16	1.83	1.33	73 %
Severance and ad valorem taxes	3.18	0.41	2.77	676 %
Exploration	0.39	0.06	0.33	550 %
Depreciation, depletion, and amortization	11.10	9.88	1.22	12 %
Abandonment and impairment of unproved properties	2.80	4.04	(1.24)	(31)%
Unused commitments	0.38	—	0.38	100 %
Bad debt expense	0.03	0.09	(0.06)	(67)%
Merger transaction costs	2.13	0.72	1.41	196 %
General and administrative expense	3.19	3.78	(0.59)	(16)%
Operating expenses	$ 29.77	$ 24.81	$ 4.96	20 %
Operating expenses, excluding impairments and abandonments and unused commitments	$ 26.59	$ 20.77	$ 5.82	28 %

Lease operating expense. Our lease operating expense increased $30.4 million, or 139%, to $52.4 million for the year ended December 31, 2021 from $22.0 million for the year ended December 31, 2020, and increased 8% on an equivalent basis per Boe. Lease operating expense on an aggregate basis increased as a result of the HighPoint, Extraction, and Crestone Peak mergers. Additionally, our overall lease operating expense during the year ended December 31, 2020 was at an unprecedented low due to the Company's concerted effort to reduce costs in response to the decline in commodity pricing experienced during 2020. The increase in lease operating expense outpaced the increase in sales volumes causing the per Boe to increase, which is within expectations and guidance on a per Boe basis.

Midstream operating expense. Our midstream operating expense increased $2.5 million, or 17%, to $17.4 million for the year ended December 31, 2021 from $14.9 million for the year ended December 31, 2020, and decreased 48% on an equivalent basis per Boe. The aggregate increase is due to the acquisition of certain midstream assets through the HighPoint and Crestone Peak mergers. Conversely, while certain midstream operating expenses correlate to sales volumes, the majority of the costs, such as compression, are fixed and thereby result in a decrease in midstream operating expense per Boe period over period.

Gathering, transportation, and processing. Gathering, transportation, and processing expense increased $47.6 million, or 281%, to $64.5 million for the year ended December 31, 2021 from $16.9 million for the year ended December 31, 2020, and increased 73% on an equivalent basis per Boe. Natural gas and NGL sales volumes have a direct correlation to gathering, transportation, and processing expense. Natural gas and NGL sales volumes increased 162% during the comparable periods. Additionally, our value-based percentage of proceeds sales contract, which tracks solely with natural gas and NGL pricing, is now our largest sales contract as a result of the mergers completed in 2021. Natural gas and NGL pricing increased at a faster pace than the natural gas and NGL sales volumes associated with said pricing causing gathering, transportation, and processing expense per Boe to increase.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased $61.3 million, or 1,619%, to $65.1 million for the year ended December 31, 2021 from $3.8 million for the year ended December 31, 2020, and increased 676% on an equivalent basis per Boe. Severance and ad valorem taxes primarily correlate to revenues, which increased by 335% for the year ended December 31, 2021 when compared to the same period in 2020. Additionally, during 2020, we refined our tax estimate based on current mill levies, taxing districts, and Company results based on commodity prices, which resulted in a total non-recurring negative adjustment of $16.3 million. Excluding this adjustment, our severance and ad valorem taxes were $20.1 million for the year ended December 31, 2020, which would make the year over year change 224%.

Depreciation, depletion, and amortization. Our depreciation, depletion, and amortization expense increased $135.7 million, or 149%, to $226.9 million for the year ended December 31, 2021 from $91.2 million for the year ended December 31, 2020, and increased 12% on an equivalent basis per Boe. The increase in depreciation, depletion, and amortization expense is the result of (i) a $4.4 billion increase in the depletable property base primarily due to the HighPoint, Extraction, and Crestone Peak mergers and (ii) a 121% increase in production between the comparable periods.

Abandonment and impairment of unproved properties. During the years ended December 31, 2021 and 2020, we incurred $57.3 million and $37.3 million, respectively, in abandonment and impairment of unproved properties. At year-end 2021, the Company did a full assessment of its locations and replaced non-core legacy locations with newly acquired locations. At year-end 2020, the Company did a reassessment of its estimated probable and possible reserve locations based largely upon economic viability and the expiration of non-core leases. Please refer to *Part II, Item 8, Note 1 - Summary of Significant Accounting Policies* for additional discussion on our impairment policy and practices.

Unused commitments. During the years ended December 31, 2021 and 2020, we incurred $7.7 million and zero, respectively, in unused commitments. As part of the HighPoint Merger, we assumed two firm natural gas pipeline transportation contracts to provide a guaranteed outlet for production from properties HighPoint had previously sold. Both firm transportation contracts required the pipeline to provide transportation capacity and required us to pay transportation charges regardless of the amount of pipeline capacity utilized. The agreements expired July 31, 2021.

Merger transaction costs. During the year ended December 31, 2021 and 2020, we incurred $43.6 million and $6.7 million, respectively, in legal, advisor, and other costs associated with the HighPoint, Extraction, and Crestone Peak mergers.

General and administrative expense. Our general and administrative expense increased $30.2 million, or 86%, to $65.1 million for the year ended December 31, 2021 from $34.9 million for the year ended December 31, 2020, and decreased 16% on an equivalent basis per Boe. The primary drivers of the aggregate increase relate to an increase in salaries, benefits, and stock compensation expense due to the aforementioned mergers. Additionally, certain one-time nonrecurring fees were incurred as it relates to these mergers as further discussed in *Note 2 - Acquisitions & Divestitures of Item 8* of this report. General and administrative expense per Boe decreased on a higher percentage basis due to oil equivalent sales volumes being 121% higher during the year ended December 31, 2021 as compared to the same period in 2020.

Derivative gain (loss). Our derivative loss for the year ended December 31, 2021 was $60.5 million as compared to a gain of $53.5 million for year ended December 31, 2020. Our derivative loss is due to settlements and fair market value adjustments caused by market prices being higher than our contracted hedge prices. Please refer to *Part II, Item 8, Note 9 - Derivatives* for additional discussion.

Interest expense. Our interest expense for the years ended December 31, 2021 and 2020 was $9.7 million and $2.0 million, respectively. Average debt outstanding for the years ended December 31, 2021 and 2020 was $217.9 million and $53.2 million, respectively. The components of interest expense for the periods presented are as follows (in thousands):

	Year Ended December 31,	
	2021	2020
Senior Notes	$ 9,903	$ —
Credit Facility	2,019	1,760
Commitment fees on available borrowing base under the Credit Facility	1,859	1,181
Letter of credit fees under the Credit Facility	326	—
Amortization of deferred financing costs	1,890	864
Capitalized interest	(6,297)	(1,760)
Total interest expense, net	$ 9,700	$ 2,045

Liquidity and Capital Resources

The Company's anticipated sources of liquidity include cash from operating activities, borrowings under the Credit Facility, potential proceeds from sales of assets, and potential proceeds from equity and/or debt capital markets transactions. Our cash flows from operating activities are subject to significant volatility due to changes in commodity prices, as well as variations in our production. The prices for these commodities are driven by a number of factors beyond our control, including global and regional product supply and demand, weather, product distribution, refining and processing capacity, regulatory constraints, and other supply chain dynamics, among other factors.

Although we cannot provide any assurance, we believe cash flows from operating activities and availability under our Credit Facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures and commitments for at least the next twelve months and, based on current expectations, for the long term.

As of December 31, 2021, our liquidity was $1.0 billion, consisting of cash on hand of $254.5 million and $778.3 million of available borrowing capacity on our Credit Facility, after giving effect to an aggregate of $21.7 million of undrawn letters of credit. Please refer to *Part II, Item 8, Note 5 - Long-term Debt* for additional discussion.

We anticipate investing between $825 million and $950 million on drilling and completion capital expenditures in 2022, which assumes running an average of 3.5 operated rigs and 3 operated crews that will drill 190 to 210 and complete 165 to 175 gross operated wells. In addition, we anticipate investing between $70 million and $90 million on land, midstream, and other capital expenditures that will support our acreage positions and overall infrastructure.

The following table summarizes our cash flows and other financial measures for the periods indicated (in thousands):

	Year Ended December 31,	
	2021	2020
Net cash provided by operating activities	$ 274,599	$ 158,796
Net cash provided by (used in) investing activities	73,547	(63,799)
Net cash used in financing activities	(118,435)	(81,247)
Cash, cash equivalents, and restricted cash	254,556	24,845
Acquisition of oil and gas properties	(1,250)	(3,210)
Exploration and development of oil and gas properties	(151,500)	(60,149)

Cash flows provided by operating activities

For the years ended December 31, 2021 and 2020, the cash receipts and disbursements were attributable to our normal operating cycle. See *Results of Operations* above for more information on the factors driving these changes.

Cash flows provided by (used in) investing activities

Net cash provided by investing activities for the year ended December 31, 2021 was primarily driven by the $223.7 million of cash acquired through mergers. However, expenditures for development of oil and natural gas properties are the primary use of our capital resources, which partially offset any inflows of the aforementioned cash acquired. The Company spent $151.5 million and $60.1 million on the exploration and development of oil and gas properties during the years ended December 31, 2021 and 2020, respectively. The Company also spent $2.0 million less on acquisitions of oil and gas properties during the year ended December 31, 2021 when compared to the same period in 2020.

Cash flows used in financing activities

Net cash used in financing activities for the year ended December 31, 2021 and 2020 was $118.4 million and $81.2 million, respectively. The change was primarily due to a $354.0 million increase in net payments on revolving credit facility balances during the year ended December 31, 2021, including the payoff of the HighPoint credit facility of $154.0 million and the Crestone Peak credit facility of $280.0 million, offset by net payments during the year ended December 31, 2020 on the Credit Facility of $80.0 million. Additionally, dividends and deferred financing costs paid totaled $60.8 million and $19.3 million, respectively. Offsetting these outflows were the proceeds from the $400.0 million issuance of 5.0% Senior Notes.

Material Commitments

We had the following material commitments as of December 31, 2021 (in thousands):

	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Delivery commitments(1)	$ 250,990	$ 71,348	$ 80,730	$ 44,753	$ 54,159
Operating leases(2)	42,531	20,044	18,227	2,674	1,586
Asset retirement obligations(3)	225,315	24,000	99,474	14,309	87,532
Total	$ 518,836	$ 115,392	$ 198,431	$ 61,736	$ 143,277

(1) The calculation on the delivery commitments is based on the firm transportation or minimum gross volume commitment schedule and applicable differential fees. Please refer to *Part II, Item* 8, *Note 6 - Commitments and Contingencies* for additional discussion on these agreements.
(2) The Company has included the minimum future commitments for its long-term operating leases. Such leases are reflected at undiscounted values. Please refer to *Part II, Item* 8, *Note 3 - Leases*, for additional discussion.
(3) Amounts represent our estimated future retirement obligations on a discounted basis. The discounted obligations are recorded as liabilities on our accompanying balance sheets as of December 31, 2021 and 2020. Because these costs typically extend many years into the future, management prepares estimates and makes judgments that are subject to future revisions based upon numerous factors. Please refer to *Part II, Item* 8, *Note 10 - Asset Retirement Obligation*, for additional discussion.

5.0% Senior Notes

On October 13, 2021, the Company issued $400 million aggregate principal amount of 5.0% Senior Notes due 2026 (the “5.0% Senior Notes”) pursuant to an indenture, dated October 13, 2021 (the “5.0% Indenture”), among Civitas Resources, the guarantors party thereto and Wells Fargo Bank, National Association, as trustee. Following the closing of the Offering, the Company used the net proceeds from the Offering and cash on hand to repay all borrowings under the Credit Facility, all borrowings outstanding under the Crestone Peak credit facility, and for general corporate purposes. Interest accrues at the rate of 5.0% per annum and will be payable semiannually in arrears on April 15 and October 15, commencing on April 15, 2022.

The 5.0% Senior Notes contain covenants that limit, among other things, the Company’s ability and the ability of its subsidiaries to: (i) incur or guarantee additional indebtedness; (ii) create liens securing indebtedness; (iii) pay dividends on or redeem or repurchase stock or subordinated debt; (iv) make specified types of investments and acquisitions; (v) enter into or permit to exist contractual limits on the ability of the Company’s subsidiaries to pay dividends to Civitas Resources; (v) enter into transactions with affiliates; and (vii) sell assets or merge with other companies. These covenants are subject to a number of important limitations and exceptions. In addition, certain of these restrictive covenants will be terminated before the 5.0% Senior Notes mature if at any time no default or event of default exists under the 5.0% Indenture and the 5.0% Senior Notes receive an investment grade rating from at least two ratings agencies. The 5.0% Indenture also contains customary events of default.

At any time prior to October 15, 2023, the Company may redeem the 5.0% Senior Notes, in whole or in part, at a redemption price equal to the sum of (i) the principal amount thereof, plus (ii) the "make-whole" premium at the redemption date, plus (iii) accrued and unpaid interest, if any, to, but excluding, the date of redemption (subject to the right of the noteholders on the relevant record date to receive interest on the relevant interest payment date). On or after October 15, 2023, the Company may redeem all or part of the 5.0% Senior Notes at redemption prices (expressed as percentages of the principal amount redeemed) equal to (i) 102.5% for the twelve-month period beginning on October 15, 2023; (ii) 101.25% for the twelve-month period beginning on October 15, 2024; and (iii) 100.0% for the twelve-month period beginning October 15, 2025 and at any time thereafter, plus accrued and unpaid interest, if any, to, but excluding, the redemption date (subject to the right of the noteholders on the relevant record date to receive interest on the relevant interest payment date).

The Company may redeem up to 35% of the aggregate principal amount of the 5.0% Senior Notes at any time prior to October 15, 2023 with an amount not to exceed the net cash proceeds from certain equity offerings at a redemption price equal to 105.0% of the principal amount of the 5.0% Senior Notes redeemed, plus accrued and unpaid interest, if any, thereon to, but not including, the redemption date, provided, however, that (i) at least 65.0% of the aggregate principal amount of the 5.0% Senior Notes originally issued on the issue date (but excluding 5.0% Senior Notes held by CIVI and its subsidiaries) remains outstanding immediately after the occurrence of such redemption (unless all such 5.0% Senior Notes are redeemed substantially concurrently) and (ii) the redemption occurs within 180 days after the date of the closing of such equity offering.

The 5.0% Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by all of Civitas' existing subsidiaries.

7.5% Senior Notes

In conjunction with the HighPoint Merger, the Company issued $100 million aggregate principal amount of 7.5% Senior Notes due 2026 pursuant to an indenture (the "7.5% Indenture"), dated April 1, 2021, by and among Civitas Resources, U.S. Bank National Association ("US Bank"), as trustee, and the subsidiary guarantors party thereto. Interest accrues at the rate of 7.5% per annum and will be payable semiannually in arrears on April 30 and October 31, commencing on October 31, 2021.

The 7.5% Indenture contains restrictive covenants that, among other things, restrict the ability of Civitas Resources, and each of its restricted subsidiaries to: (i) incur additional indebtedness and issue preferred stock; (ii) pay dividends or make other distributions in respect of the Company's common stock; (iii) make other restricted payments and investments; (iv) create liens; (v) restrict distributions or other payments from Civitas' restricted subsidiaries; (v) sell assets, including capital stock of restricted subsidiaries; (vi) merge or consolidate with other entities; and (vii) enter into transactions with affiliates. These restrictive covenants are subject to a number of important qualifications and limitations. In addition, certain of these restrictive covenants will be suspended before the 7.5% Senior Notes mature if at any time no default or event of default exists under the 7.5% Indenture and the 7.5% Senior Notes receive an investment grade rating from at least two ratings agencies. The 7.5% Indenture also contains customary events of default.

The 7.5% Senior Notes are redeemable at the Company's option (an "Optional Redemption"), in whole or in part, prior to April 30, 2022 at a redemption price equal to 107.5% of the aggregate principal to be redeemed, plus unpaid accrued interest, if any, through the Optional Redemption date. On or after April 30, 2022, the Optional Redemption price will be equal to 100.0% of the aggregate principal amount of the 7.5% Senior Notes to be redeemed, plus unpaid accrued interest, if any, through Optional Redemption date.

The 7.5% Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by all of Civitas' existing subsidiaries.

Credit Facility

In December 2018, the Company entered into a reserve-based revolving facility, as the borrower, with JPMorgan Chase Bank, N.A., ("JPMorgan") as the administrative agent, and a syndicate of financial institutions, as lenders, that matured on December 7, 2023. The November 2021 redetermination as part of the Amended & Restated Credit Agreement (defined below) resulted in a borrowing base of $1.0 billion, with elected commitments set at $800 million. The next scheduled redetermination is set to occur in April 2022.

The Credit Facility contains customary representations and affirmative covenants. The Credit Facility also contains customary negative covenants, which, among other things, and subject to certain exceptions, include restrictions on (i) liens, (ii) indebtedness, guarantees and other obligations, (iii) restrictions in agreements on liens and distributions, (iv) mergers or consolidations, (v) asset sales, (vi) restricted payments, (vii) investments, (viii) affiliate transactions, (ix) change of business, (x) foreign operations or subsidiaries, (xi) name changes, (xii) use of proceeds, letters of credit, (xiii) gas imbalances, (xiv) hedging transactions, (xv) additional subsidiaries, (xvi) changes in fiscal year or fiscal quarter, (xvii) operating leases, (xviii) prepayments of certain debt and other obligations, (xix) sales or discounts of receivables, (xx) dividend payment thresholds, and (xi) cash balances. The Credit Parties are subject to certain financial covenants under the Credit Facility, as tested on the last day of each fiscal quarter, including, without limitation, (i) a maximum ratio of the Company's consolidated indebtedness (subject to certain exclusions) to earnings before interest, income taxes, depreciation, depletion, and amortization, exploration expense, and other non-cash charges (“EBITDAX”) and (ii) a current ratio, as defined in the agreement, inclusive of the unused commitments then available to be borrowed, to not be less than 1.00 to 1.

Under the terms of the Credit Facility, as amended in June 2020 (the “First Amendment”), borrowings bore interest at a per annum rate equal to, at the option of the Company, either (i) a LIBOR, subject to a 0% LIBOR floor plus a margin of 2.00% to 3.00%, based on the utilization of the Credit Facility (the “Eurodollar Rate”) or (ii) a fluctuating interest rate per annum equal to the greatest of (a) the rate of interest publicly announced by JPMorgan Chase Bank, N.A. as its prime rate, (b) the rate of interest published by the Federal Reserve Bank of New York as the federal funds effective rate, (c) the rate of interest published by the Federal Reserve Bank of New York as the overnight bank funding rate, or (d) a LIBOR offered rate for a one-month interest period, subject to a 0% LIBOR floor plus a margin of 1.00% to 2.00%, based on the utilization of the Credit Facility (the “Reference Rate”). Interest on borrowings that bear interest at the Eurodollar Rate shall be payable on the last day of the applicable interest period selected by the Company, which shall be one, two, three, or six months, and interest on borrowings that bear interest at the Reference Rate shall be payable quarterly in arrears.

On April 1, 2021, in conjunction with the HighPoint Merger, the Company, together with certain of its subsidiaries, entered into the Second Amendment (the “Second Amendment”) to the Credit Facility (as amended, restated, supplemented or otherwise modified) to, among other things: (i) increase the aggregate maximum commitment amount from $750.0 million to $1.0 billion; (ii) increase the available borrowing base from $260.0 million to $500.0 million; (iii) increase the Eurodollar Rate margin to 3.00% to 4.00%; (iv) increase the Reference Rate margin to 2.00% to 3.00%; (v) increase (A) the LIBOR floor from 0% to .50% and (B) the alternate base rate floor from 0% to 1.50%; (vi) decrease for any fiscal quarter ending on or after April 1, 2021, the maximum permitted net leverage ratio from 3.50 to 3.0; and (viii) amend certain other covenants and provisions.

On November 1, 2021, in conjunction with the Transactions, the Company, as borrower, JPMorgan, as the administrative agent, and a syndicate of financial institutions, as lenders, entered into an Amended and Restated Credit Agreement, dated as of November 1, 2021 having an Aggregate Maximum Credit Amount (as defined in the Amended and Restated Credit Agreement) of $2.0 billion. The Amended and Restated Credit Agreement, among other things: (i) increases the aggregate elected commitments to from $400.0 million to $800.0 million, (ii) increases the available borrowing base from $500.0 million to $1.0 billion, (iii) extends the maturity date of the Amended and Restated Credit Agreement to November 1, 2025 and (iv) amends the borrowing base adjustment provisions such that, between borrowing base determinations, downward adjustments related to the incurrence of certain permitted indebtedness will only occur (x) until the occurrence of the April 2022 borrowing base determination, if such indebtedness exceeds $500.0 million and, (y) thereafter, if either (A) such indebtedness exceeds $500.0 million and the Company’s pro-forma leverage ratio is less than or equal to 1.50 to 1, or (B) the Company’s pro-forma leverage ratio is greater than 1.50 to 1. Under the Amended and Restated Credit Agreement, the Company’s Credit Facility will be guaranteed by all restricted domestic subsidiaries of the Company including by the Extraction Surviving Corporation, the Crestone Surviving Entity, and all their respective subsidiaries, and will be secured by first priority security interests on substantially all assets, including a mortgage on at least 90% of the total value of the proved oil and gas properties evaluated in the most recently delivered reserve reports prior to the amendment effective date, including any engineering reports relating to the oil and gas properties of the Extraction Surviving Corporation, the Crestone Surviving Entity, their respective subsidiaries, of each of the Company, all restricted domestic subsidiaries of the Company, the Extraction Surviving Corporation and the Crestone Surviving Entity, in each case, subject to customary exceptions.

The Company was in compliance with all covenants as of December 31, 2021 and through the filing date of this report.

Our weighted-average interest rates on borrowings from the Credit Facility were 3.6% and 3.1% for the years ended December 31, 2021 and 2020, respectively. As of December 31, 2021 and as of the date of filing, we had a zero balance on our Credit Facility.

Non-GAAP Financial Measures

Adjusted EBITDAX represents earnings before interest, income taxes, depreciation, depletion, and amortization, exploration expense, and other non-cash and non-recurring charges. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally non-recurring in nature or whose timing and/or amount cannot be reasonably estimated. Adjusted EBITDAX is a non-GAAP measure that we present because we believe it provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to financial covenants under our Credit Facility based on adjusted EBITDAX ratios as further described above in *Liquidity and Capital Resources*. In addition, adjusted EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income, net cash provided by operating activities, or other profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all items that affect net income and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies.

The following table presents a reconciliation of the GAAP financial measure of net income to the non-GAAP financial measure of Adjusted EBITDAX (in thousands):

	Year Ended December 31,	
	2021	2020
Net income	$ 178,921	$ 103,528
Exploration	7,937	596
Depreciation, depletion, and amortization	226,931	91,242
Abandonment and impairment of unproved properties	57,260	37,343
Stock-based Compensation[(1)]	15,558	6,156
Non-recurring general and administrative expense[(1)]	2,609	1,337
Merger transaction costs	43,555	6,676
Unused commitments	7,692	—
(Gain) loss on property transactions, net	(1,932)	1,398
Interest expense, net	9,700	2,045
Severance and ad valorem taxes adjustment[(2)]	—	(16,291)
Derivative (gain) loss	60,510	(53,462)
Derivative cash settlements gain (loss)	(275,914)	49,406
Income tax (benefit) expense	72,858	(60,547)
Adjusted EBITDAX	$ 405,685	$ 169,427

(1) Included as a portion of general and administrative expense in the accompanying consolidated statements of operations and comprehensive income (“statements of operations”).

(2) Included as a portion of severance and ad valorem taxes in the accompanying statements of operations.

Critical Accounting Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP"). The preparation of these statements requires us to make certain assumptions, judgments, and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities and commitments as of the date of our financial statements. We evaluate our estimates and assumptions on an ongoing basis. We analyze and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates. We believe the following discussions of critical accounting estimates address all important accounting areas where the nature of accounting estimates or assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change. Our significant accounting policies are described in *Part II, Item 8, Note 1 - Summary of Significant Accounting Policies*.

Property and Equipment

Proved Properties. The Company accounts for its oil and gas properties under the successful efforts method of accounting. Under this method, the costs of development wells are capitalized to proved properties whether those wells are successful or unsuccessful. Capitalized drilling and completion costs, including lease and well equipment, intangible development costs, and operational support facilities are depleted using the units-of-production method based on estimated proved developed reserves. Proved leasehold costs are also depleted; however, the units-of-production method is based on estimated total proved reserves. The computation of depletion expense takes into consideration restoration, dismantlement, and abandonment costs as well as the anticipated proceeds from salvaging equipment. Because all of our proved properties are currently located in a single field, we apply depletion on a single field basis.

The Company assesses proved properties for impairment whenever events or circumstances indicate that their carrying value may not be recoverable. If carrying values exceed undiscounted future net cash flows, impairment is measured and recorded at fair value. Because there usually is a lack of quoted market prices for proved properties, the Company estimates the fair value using valuation techniques that convert estimated future net cash flows to a single discounted amount. Significant inputs and assumptions to this estimation include, but are not limited to, reserves volumes, future operating and development costs, future commodity prices, inclusive of applicable differentials, and a market-based weighted average cost of capital rate. The expected future cash flows used for impairment reviews include future production volumes associated with proved developed producing reserves and risk-adjusted proved undeveloped reserves, and when needed, probable and possible reserves.

Unproved Properties. Unproved properties consist of the costs to acquire undeveloped leases and are not subject to depletion until they are transferred to proved properties. Leasehold costs are transferred to proved properties on an ongoing basis as the properties to which they relate are evaluated and proved reserves established. Unproved properties are routinely evaluated for continued capitalization or impairment. On a quarterly basis, management assesses undeveloped leasehold costs for impairment by considering, among other things, remaining lease terms, future drilling plans and capital availability to execute such plans, commodity price outlooks, recent operational results, reservoir performance and geology, and estimated acreage value based on prices received for similar, recent acreage transactions by the Company or other market participants. Changes in our assumptions of the estimated nonproductive portion of our undeveloped leases could result in additional impairment expense.

Oil and Natural Gas Reserves. The successful efforts method of accounting outlined above inherently relies on the estimation of proved oil and natural gas reserves. Reserve quantities and the related estimates of future net cash flows are critical inputs in our calculation of units-of-production depletion and our evaluation of proved and unproved properties for impairment. The process of estimating and evaluating crude oil and natural gas reserves is complex, requiring the evaluation of available geological, geophysical, engineering and economic data to estimate underground accumulations of oil and natural gas that cannot be precisely measured. Consequently, the Company engages a third-party petroleum consultant to prepare our estimates of oil and natural gas reserves. Significant inputs and engineering assumptions used in developing the estimates of proved oil and natural gas reserves include reserves volumes, future operating and development costs, historical commodity prices, and the Company’s ability to convert proved undeveloped reserves to producing properties within five years of their initial proved booking.

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, revisions in existing reserve estimates occur. We cannot predict the amounts or timing of such future revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of proved property.

Business Combinations

As part of our business strategy, we regularly pursue the acquisition of oil and natural gas properties. We utilize the acquisition method to account for acquisitions of businesses. Pursuant to this method, we allocate the cost of the acquisition, or purchase price, to assets acquired and liabilities assumed based on fair values as of the acquisition date.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant of these assumptions relate to the estimated fair values assigned to proved and unproved properties. Since sufficient market data was not available regarding the fair values of our acquired proved and unproved oil and gas properties, we engaged a third-party valuation expert to assist in preparing fair value estimates. We utilized a discounted cash flow approach, based on market participant assumptions. Significant judgments and assumptions are inherent in these estimates and include, among other things, reserve quantities and classification, pace of drilling plans, future commodity prices, future development and lease operating costs, and discount rates using a market-based weighted average cost of capital determined at the time of the acquisition. When estimating the fair value of unproved properties, additional risk-weighting adjustments are applied to probable and possible reserves.

Estimated fair values ascribed to assets acquired can have a significant impact on future results of operations presented in the Company's financial statements. For example, a higher fair value ascribed to a proved properties results in higher DD&A expense, which results in lower net income. As discussed above, estimated fair values assigned to proved and unproved properties are dependent on estimates of reserve quantities, future commodity prices, as well as development and operating costs. In the event that reserve quantities or future commodity prices are lower than those used as inputs to determine estimates of acquisition-date fair values, the likelihood increases that certain costs may be determined to not be recoverable.

In addition, we record deferred taxes for any differences between the assigned fair values and tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Effects of Inflation and Pricing

Inflation in the United States averaged 4.7% in 2021, 1.2% in 2020, and 1.8% in 2019. Although inflation increased steadily and significantly in 2021 and was at near 40-year high at 7.0% as of December 31, 2021, inflation did not have a material impact on our results of operations for the period ended December 31, 2021, or for the periods ended December 31, 2020 and 2019.

The Company tends to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations, depletion expense, impairment assessments of oil and gas properties, ARO, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and the rate of return associated with the wells they develop and can hinder their ability to raise capital, borrow money, and retain personnel. With the current increase in commodity prices and drilling activity, we expect that there will be increased costs associated with parts, materials, labor and other necessary drilling and completions related resources, including contracts for drilling and workover rigs and oilfield service companies.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

Oil and Natural Gas Price Risk

Our financial condition, results of operations, and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for oil and natural gas, the global supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels, local and global politics, and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse effect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations, and capital resources. If oil and natural gas SEC prices declined by 10%, our proved reserve volumes would decrease by 1% and our PV-10 value as of December 31, 2021 would decrease by approximately 16% or $859.7 million. If oil and natural gas SEC prices increased by 10%, our proved reserve volumes would increase by 1% and our PV-10 value as of December 31, 2021 would increase by approximately 16% or $865.4 million.

PV-10 is a non-GAAP financial measure. Please refer to *Estimated Proved Reserves* under Part I, Item 1 of this Annual Report on Form 10-K for management's discussion of this non-GAAP financial measure.

Commodity Price Derivative Contracts

Our primary commodity risk management objective is to protect the Company's balance sheet via the reduction in cash flow volatility. We enter into derivative contracts for oil, natural gas, and natural gas liquids using NYMEX futures or over-the-counter derivative financial instruments. The types of derivative instruments that we use include swaps, collars, and puts.

Upon settlement of the contract(s), if the relevant market commodity price exceeds our contracted swap price, or the collar's ceiling strike price, we are required to pay our counterparty the difference for the volume of production associated with the contract. Generally, this payment is made up to 15 business days prior to the receipt of cash payments from our customers. This could have an adverse impact on our cash flows for the period between derivative settlements and payments for revenue earned.

While we may reduce the potential negative impact of lower commodity prices, we may also be prevented from realizing the benefits of favorable price changes in the physical market.

Presently, our derivative contracts have been executed with 10 counterparties, all but one of which are members of our Credit Facility syndicate. We enter into contracts with counterparties whom we believe are well capitalized. However, if our counterparties fail to perform their obligations under the contracts, we could suffer financial loss.

Please refer to the *Derivative Activities* section of Part I, Item 1 of this Annual Report on Form 10-K for summary derivative activity tables.

For the oil, natural gas, and NGL derivatives outstanding at December 31, 2021, a hypothetical upward or downward shift of 10% per Bbl, MMBtu, or Gallon in the forward curve for the related indices as of December 31, 2021 would increase our derivative loss by $82.7 million or decrease it by $79.2 million, respectively.

Interest Rates

At both December 31, 2021 and on the filing date of this report, we had a zero balance on our Credit Facility. Borrowings under our Credit Facility bear interest at a fluctuating rate that is tied to an adjusted Base Rate or LIBOR, at our option. Any increases in these interest rates can have an adverse impact on our results of operations and cash flows. As of December 31, 2021 and through the filing date of this report, the Company was in compliance with all financial and non-financial covenants.

Counterparty and Customer Credit Risk

In connection with our derivatives activity, we have exposure to financial institutions in the form of derivative transactions. Presently, our derivative contracts have been executed with 10 counterparties, all but one of which are members of our Credit Facility syndicate. All counterparties on our derivative instruments currently in place have investment grade credit ratings.

We are also subject to credit risk due to concentration of our oil and natural gas receivables with certain significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. We review the credit rating, payment history, and financial resources of our customers, but we do not require our customers to post collateral.

Marketability of Our Production

The marketability of our production depends in part upon the availability, proximity, and capacity of third-party refineries, access to regional trucking, pipeline and rail infrastructure, natural gas gathering systems, and processing facilities. We deliver crude oil and natural gas produced through trucking services, pipelines, and rail facilities that we do not own. The lack of availability or capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of accidents, weather, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

Currently, there are no pipeline systems that service wells in our French Lake area of the Wattenberg Field. If neither we nor a third-party constructs the required pipeline system, we may not be able to fully test or develop our resources in French Lake.

Item 8. ***Financial Statements and Supplementary Data.***

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Civitas Resources, Inc. (formerly Bonanza Creek Energy, Inc.)

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Civitas Resources, Inc. (formerly Bonanza Creek Energy, Inc.) and subsidiaries (the "Company") as of December 31, 2021 and 2020, and the related consolidated statements of operations and comprehensive income, stockholders' equity, and cash flows, for each of the three years in the period ended December 31, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 8, 2022 expressed an unqualified opinion on the Company's internal control over financial reporting.

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 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. Our audit 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 audit 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 Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate 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 matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Proved Oil and Gas Properties and Depletion — Estimated Proved Reserves — Refer to Note 1 to the consolidated financial statements

Critical Audit Matter Description

The Company’s capitalized costs of proved oil and gas properties are depleted using the units of production method based on estimated proved reserves. The development of the Company’s estimated proved reserve volumes requires management to make significant estimates and assumptions, including the Company’s ability to convert proved undeveloped reserves to producing properties within five years of their initial proved booking. The Company engages an independent reserve engineer to estimate oil and natural gas quantities using these estimates and assumptions and engineering data. Changes in these assumptions could materially affect the estimated quantities of the Company’s reserves. The proved oil and gas properties, net balance was $5,027 million, as of December 31, 2021. Depletion expense was $212.5 million for the year ended December 31, 2021.

Given the significant judgments made by management, performing audit procedures to evaluate the Company's estimated proved reserve quantities, including management's estimates and assumptions related to converting proved undeveloped reserves to producing properties within five years, required a high degree of auditor judgment and an increased extent of effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant judgments and assumptions related to proved reserve quantities and converting proved undeveloped reserves to producing properties within five years included the following, among others:

- We tested the operating effectiveness of controls related to the Company's estimation of proved reserves, including controls relating to the five-year conversion plan.
- We evaluated the Company's estimated proved reserves and reasonableness of management's five-year conversion plan by:
    - Comparing the Company's reserve estimated future production to historical production volumes.
    - Assessing the reasonableness of the production volume decline curves by comparing to historical decline curve estimates.
    - Comparing the forecasts to historical conversions of proved undeveloped oil and gas reserves into proved developed oil and gas reserves.
    - Comparing the forecasts to the Company's drill plan and the availability of capital relative to the drill plan.
    - Reviewing internal communications to management and the Board of Directors.
    - Comparing the forecasts to forecasted information included in Company press releases as well as in analyst and industry reports for the Company and certain of its peer companies.
- We evaluated the experience, qualifications and objectivity of management's expert, an independent reserve engineering firm, including the methodologies used to estimate proved reserve quantities.

Acquisitions and Divestitures — Valuation of Oil and Gas Properties — Refer to Note 1 and Note 2 to the consolidated financial statements

Critical Audit Matter Description

As described in Note 2 to the consolidated financial statements, the Company acquired HighPoint Resources Corporation ("HighPoint"), Extraction Oil & Gas, Inc. ("Extraction"), and CPPIB Crestone Peak Resources America Inc. ("Crestone Peak") in acquisitions accounted for as business combinations, which required assets acquired and liabilities assumed to be measured at their acquisition date fair values, including approximately $4,860 million related to the fair values of acquired oil and gas properties. Management applied significant judgment in estimating the fair value of oil and gas properties acquired, which involved the use of a discounted cash flow model that incorporated oil and natural gas price escalation factors, development and production risk factors and the weighted average cost of capital rate.

The principal considerations for our determination that performing procedures relating to the valuation of oil and gas properties from the acquisitions of HighPoint, Extraction and Crestone Peak is a critical audit matter are (i) the significant judgments made by management, including the use of management's specialists as discussed in the previous Critical Audit Matter, as well the use of an independent accounting firm to estimate oil and natural gas price escalation factors, development and production risk factors and the weighted average cost of capital rate when developing the fair value measurement of acquired oil and gas properties; (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating significant assumptions of the nature discussed in the previous Critical Audit Matter, as well as assumptions used in the discounted cash flow model related to oil and natural gas price escalation factors, development and production risk factors and the weighted average cost of capital rate; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant judgments and assumptions related to oil and natural gas price escalation factors, development and production risk factors and the weighted average cost of capital rate included the following, among others:

- We tested the operating effectiveness of controls related to the Company’s assumptions related to oil and natural gas price escalation factors, development and production risk factors and the weighted average cost of capital rate used within the valuation of acquired oil and gas properties.
- We evaluated the appropriateness of the discounted cash flow model by:
    - Testing the completeness and accuracy of underlying data used in the discounted cash flow model.
    - Evaluating the reasonableness of significant assumptions used by management related to oil and natural gas price escalation factors, development and production risk factors and the weighted average cost of capital rate.
    - Utilizing professionals with specialized skill and knowledge to assist in the evaluation of the discounted cash flow model, including oil and natural gas price escalation factors, development and production risk factors and the weighted average cost of capital rate used.
- We evaluated the experience, qualifications, and objectivity of management’s experts, an independent accounting firm, including the methodologies used to estimate oil and natural gas price escalation factors, development and production risk factors and the weighted average cost of capital rate, as well as an independent reserve engineering firm as discussed in the previous Critical Audit Matter.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 8, 2022

We have served as the Company's auditor since 2019.

CIVITAS RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except per share amounts)

	As of December 31, 2021	As of December 31, 2020
ASSETS		
Current assets:		
Cash and cash equivalents	$ 254,454	$ 24,743
Accounts receivable, net:		
Oil, natural gas, and NGL sales	362,262	32,673
Joint interest and other	66,390	14,748
Prepaid expenses and other	21,052	3,574
Inventory of oilfield equipment	12,386	9,185
Derivative assets	3,393	7,482
Total current assets	719,937	92,405
Property and equipment (successful efforts method):		
Proved properties	5,457,213	1,056,773
Less: accumulated depreciation, depletion, and amortization	(430,201)	(211,432)
Total proved properties, net	5,027,012	845,341
Unproved properties	688,895	98,122
Wells in progress	177,296	50,609
Other property and equipment, net of accumulated depreciation of $4,742 in 2021 and $3,737 in 2020	51,639	3,239
Total property and equipment, net	5,944,842	997,311
Right-of-use assets	39,885	29,705
Deferred income tax assets	22,284	60,520
Other noncurrent assets	14,085	2,871
Total assets	$ 6,741,033	$ 1,182,812
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 246,188	$ 12,093
Production taxes payable	144,408	25,332
Oil and natural gas revenue distribution payable	466,233	18,613
Lease liability	18,873	12,044
Derivative liability	219,804	6,402
Asset retirement obligations	24,000	—
Total current liabilities	1,119,506	74,484
Long-term liabilities:		
Senior notes	491,710	—
Lease liability	21,398	17,978
Ad valorem taxes	232,147	15,069
Derivative liability	19,959	1,330
Asset retirement obligations	201,315	28,699
Total liabilities	2,086,035	137,560
Commitments and contingencies (note 6)		
Stockholders' equity:		
Preferred stock, $.01 par value, 25,000,000 shares authorized, none outstanding	—	—
Common stock, $.01 par value, 225,000,000 shares authorized, 84,572,846 and 20,839,227 issued and outstanding as of December 31, 2021 and 2020, respectively	4,912	4,282
Additional paid-in capital	4,199,108	707,209
Retained earnings	450,978	333,761
Total stockholders' equity	4,654,998	1,045,252
Total liabilities and stockholders' equity	$ 6,741,033	$ 1,182,812

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

CIVITAS RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(in thousands, except per share amounts)

	Year Ended December 31,		
	2021	2020	2019
Operating net revenues:			
Oil, natural gas, and NGL sales	$ 930,614	$ 218,090	$ 313,220
Operating expenses:			
Lease operating expense	52,391	21,957	25,249
Midstream operating expense	17,426	14,948	12,014
Gathering, transportation, and processing	64,507	16,932	16,682
Severance and ad valorem taxes	65,113	3,787	25,598
Exploration	7,937	596	797
Depreciation, depletion, and amortization	226,931	91,242	76,453
Abandonment and impairment of unproved properties	57,260	37,343	11,201
Unused commitments	7,692	—	—
Bad debt expense	607	818	—
Merger transaction costs	43,555	6,676	—
General and administrative expense (including $15,558, $6,156, and $6,886, respectively, of stock-based compensation)	65,132	34,936	39,668
Total operating expenses	608,551	229,235	207,662
Other income (expense):			
Derivative gain (loss)	(60,510)	53,462	(37,145)
Interest expense, net	(9,700)	(2,045)	(2,650)
Gain (loss) on property transactions, net	1,932	(1,398)	1,177
Other income (expense)	(2,006)	4,107	127
Total other income (expense)	(70,284)	54,126	(38,491)
Income from operations before income taxes	251,779	42,981	67,067
Income tax benefit (expense)	(72,858)	60,547	—
Net income	$ 178,921	$ 103,528	$ 67,067
Comprehensive income	$ 178,921	$ 103,528	$ 67,067
Net income per common share:			
Basic	$ 4.82	$ 4.98	$ 3.25
Diluted	$ 4.74	$ 4.95	$ 3.24
Weighted-average common shares outstanding			
Basic	37,155	20,774	20,612
Diluted	37,746	20,912	20,681

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

CIVITAS RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands, except per share amounts)

	Common Stock		Additional Paid-In	Accumulated	
	Shares	Amount	Capital	Earnings	Total
Balances, January 1, 2019	20,543,940	$ 4,286	$ 696,461	$ 163,166	$ 863,913
Restricted common stock issued	146,359	—	—	—	—
Restricted stock used for tax withholdings	(46,561)	(2)	(1,174)	—	(1,176)
Stock-based compensation	—	—	6,886	—	6,886
Net income	—	—	—	67,067	67,067
Balances, December 31, 2019	20,643,738	4,284	702,173	230,233	936,690
Restricted common stock issued	259,995	—	—	—	—
Restricted stock used for tax withholdings	(64,506)	(2)	(1,120)	—	(1,122)
Stock-based compensation	—	—	6,156	—	6,156
Net income	—	—	—	103,528	103,528
Balances, December 31, 2020	20,839,227	4,282	707,209	333,761	1,045,252
Issuance pursuant to acquisitions	63,397,194	634	3,403,216	—	3,403,850
Restricted common stock issued	415,856	—	—	—	—
Restricted stock used for tax withholdings	(125,740)	(4)	(5,923)	—	(5,927)
Exercise of stock options	46,309	—	1,585	—	1,585
Stock-based compensation	—	—	15,558	—	15,558
Issuance of warrants	—	—	77,463	—	77,463
Cash dividends, $1.16 per share	—	—	—	(61,704)	(61,704)
Net income	—	—	—	178,921	178,921
Balances, December 31, 2021	84,572,846	$ 4,912	$ 4,199,108	$ 450,978	$ 4,654,998

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

CIVITAS RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31, 2021	2020	2019
Cash flows from operating activities:			
Net income	$ 178,921	$ 103,528	$ 67,067
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, and amortization	226,931	91,242	76,453
Deferred income tax expense (benefit)	72,858	(60,520)	—
Abandonment and impairment of unproved properties	57,260	37,343	11,201
Stock-based compensation	15,558	6,156	6,886
Amortization of deferred financing costs	1,890	864	487
Derivative (gain) loss	60,510	(53,462)	37,145
Derivative cash settlements gain (loss)	(275,914)	49,406	1,691
(Gain) loss on property transactions, net	(1,932)	1,398	(1,177)
Other	90	(186)	4,399
Changes in current assets and liabilities:			
Accounts receivable, net	(100,881)	24,945	(2,688)
Prepaid expenses and other assets	(3,338)	3,352	(2,415)
Accounts payable and accrued liabilities	47,510	(41,278)	28,320
Settlement of asset retirement obligations	(4,864)	(3,992)	(2,722)
Net cash provided by operating activities	274,599	158,796	224,647
Cash flows from investing activities:			
Acquisition of oil and natural gas properties	(1,250)	(3,210)	(14,087)
Cash acquired	223,692	—	—
Exploration and development of oil and natural gas properties	(151,500)	(60,149)	(242,487)
Proceeds from sale of oil and natural gas properties	—	—	1,757
Proceeds from (additions to) other property and equipment	2,393	(440)	(341)
Proceeds from note receivable	212	—	—
Net cash provided by (used in) investing activities	73,547	(63,799)	(255,158)
Cash flows from financing activities:			
Proceeds from credit facility	155,000	45,000	55,000
Payments to credit facility	(589,000)	(125,000)	(25,000)
Proceeds from issuance of senior notes	400,000	—	—
Proceeds from exercise of stock options	1,585	—	—
Dividends paid	(60,780)	—	—
Payment of employee tax withholdings in exchange for the return of common stock	(5,927)	(1,122)	(1,176)
Deferred financing costs	(19,292)	(23)	(220)
Principal payments on finance lease obligations	(21)	(102)	—
Net cash provided by (used in) financing activities	(118,435)	(81,247)	28,604
Net change in cash, cash equivalents, and restricted cash	229,711	13,750	(1,907)
Cash, cash equivalents, and restricted cash:			
Beginning of period	24,845	11,095	13,002
End of period	$ 254,556	$ 24,845	$ 11,095
Supplemental cash flow disclosure[(1)]:			
Non-cash investing activities[(2)]	$ 4,911,186	$ —	$ —
Non-cash financing activities[(3)]	$ 3,481,312	$ —	$ —
Cash paid for interest, net of capitalization	$ 1,829	$ 1,546	$ 4,110
Cash paid for income taxes	$ 14,000	$ —	$ —
Receivables exchanged for additional interests in oil and natural gas properties	$ —	$ 8,299	$ —
Changes in working capital related to drilling expenditures	$ (128,977)	$ 2,795	$ 30,354

(1) Refer to *Note 3 - Leases* in the notes to the consolidated financial statements for discussion of right-of-use assets obtained in exchange for lease liabilities.
(2) Includes $542.6 million, $2,109.5 million, and $2,259.1 million in non-cash property additions related to the HighPoint, Extraction, and Crestone Peak mergers, respectively.
(3) Includes $374.9 million, $1,844.1 million, and $1,262.2 million in non-cash consideration related to the HighPoint, Extraction, and Crestone Peak mergers, respectively.

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

CIVITAS RESOURCES, INC. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations

Civitas is an independent Denver-based exploration and production company focused on the acquisition, development, and production of oil and associated liquids-rich natural gas in the Rocky Mountain region, primarily in the Wattenberg Field of the DJ Basin.

Basis of Presentation

The consolidated financial statements include the accounts of the Company. All significant intercompany balances and transactions have been eliminated in consolidation. The consolidated financial statements included herein were prepared from the records of the Company in accordance with GAAP, the instructions to Form 10-K, and Regulation S-X. Additionally, certain prior period amounts have been reclassified to conform to current period presentation in the accompanying financial statements. During the current year, the Company is separately presenting Production taxes payable on the accompanying balance sheets. Accordingly, prior year amounts have been reclassified from Accounts payable and accrued expenses to conform to current year presentation.

In connection with the preparation of the consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of December 31, 2021, through the filing date of this report.

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities and commitments as of the date of our financial statements. Actual results could differ from those estimates.

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the development and production of oil, natural gas, and NGLs, and all of the Company's operations are conducted in the continental United States.

Cash and Cash Equivalents

The Company considers all highly liquid investments with original maturity dates of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximate fair value due to the short-term nature of these instruments. The Company maintains cash balances in excess of federal deposit insurance limits as of December 31, 2021 and 2020, potentially subjecting the Company to a concentration of credit risk. To mitigate this risk, we maintain our cash and cash equivalents in the form of money market and checking accounts with financial institutions that we believe are creditworthy and are also lenders under our Credit Facility.

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the accompanying balance sheets, which sums to the total of such amounts shown in the accompanying statements of cash flows (in thousands):

	As of December 31,		
	2021	2020	2019
Cash and cash equivalents	$ 254,454	$ 24,743	$ 11,008
Restricted cash[1]	102	102	87
Total cash, cash equivalents, and restricted cash	$ 254,556	$ 24,845	$ 11,095

(1) Included in other noncurrent assets and consists of funds for road maintenance and repairs.

Accounts Receivable

The Company’s accounts receivable primarily consists of receivables due from purchasers of the Company's oil, natural gas, and NGL production and from joint interest owners on properties the Company operates. The Company is exposed to credit risk in the event of nonpayment by the purchasers of its production and/or joint interest owners on the properties it operates, nearly all of which are concentrated in energy-related industries. The Company continuously evaluates the creditworthiness of the Company's purchasers and joint interest owners on the properties it operates. Generally, the Company’s oil, natural gas, and NGLs receivables are collected within one to two months. For receivables due from joint interest owners, the Company generally has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. The Company has historically experienced minimal bad debts.

The Company does not believe the loss of any single purchaser of its production would materially impact its financial position or results of operations, as oil, natural gas, and NGLs are products with well-established and highly liquid markets. For the periods presented below, the following purchasers of the Company's production accounted for more than 10% of the Company's revenue as follows:

	Year Ended December 31,		
	2021	2020	2019
Customer A	43 %	77 %	82 %
Customer B	15 %	— %	— %
Customer C	13 %	9 %	6 %

Inventory of Oilfield Equipment

Inventory of oilfield equipment consists of material and supplies to be used in connection with the Company’s operations. These inventories are recorded and relieved using the weighted average cost method and are stated at the lower of cost or net realizable value, which approximates fair value.

Property and Equipment

Proved Properties. The Company accounts for its oil and natural gas properties under the successful efforts method of accounting. Under this method, the costs of development wells are capitalized to proved properties whether those wells are successful or unsuccessful. Capitalized drilling and completion costs, including lease and well equipment, intangible development costs, and operational support facilities are depleted using the units-of-production method based on estimated proved developed reserves. Proved leasehold costs are also depleted; however, the units-of-production method is based on estimated total proved reserves. The computation of depletion expense takes into consideration restoration, dismantlement, and abandonment costs as well as the anticipated proceeds from salvaging equipment. Because all of our proved properties are currently located in a single field, we apply depletion on a single field basis. During the years ended December 31, 2021, 2020, and 2019, the Company incurred depletion expense of $212.5 million, $82.6 million, and $69.3 million, respectively.

The Company assesses proved properties for impairment whenever events or circumstances indicate that their carrying value may not be recoverable. If carrying values exceed undiscounted future net cash flows, impairment is measured and recorded at fair value. Because there usually is a lack of quoted market prices for proved properties, the Company estimates the fair value using valuation techniques that convert estimated future net cash flows to a single discounted amount. Significant inputs and assumptions to this estimation include, but are not limited to, reserves volumes, future operating and development costs, future commodity prices, inclusive of applicable differentials, and a market-based weighted average cost of capital rate. The expected future cash flows used for impairment reviews include future production volumes associated with proved developed producing reserves and risk-adjusted proved undeveloped reserves, and when needed, probable and possible reserves.

The partial sale of a proved property within an existing field is accounted for as a normal retirement and no net gain or loss on divestiture activity is recognized as long as such treatment does not significantly affect the units-of-production depletion rate. The sale of a partial interest in an individual proved property is accounted for as a recovery of cost. A net gain or loss on divestiture activity is recognized in the accompanying statements of operations for all other sales of proved properties.

As of December 31, 2021, the net book value of the Company's midstream assets was $276.1 million in the accompanying balance sheets. Depreciation on the Company's midstream assets is calculated using the straight-line method over the estimated useful lives of the assets and properties they serve, which is approximately 30 years.

Unproved Properties. Unproved properties consist of the costs to acquire undeveloped leases and are not subject to depletion until they are transferred to proved properties. Leasehold costs are transferred to proved properties on an ongoing basis as the properties to which they relate are evaluated and proved reserves established.

Additional costs not subject to depletion include costs associated with development wells in progress or awaiting completion at year-end. These costs are transferred into costs subject to depletion on an ongoing basis as these wells are completed and proved reserves are established or confirmed.

Unproved properties are routinely evaluated for continued capitalization or impairment. On a quarterly basis, management assesses undeveloped leasehold costs for impairment by considering, among other things, remaining lease terms, future drilling plans and capital availability to execute such plans, commodity price outlooks, recent operational results, reservoir performance and geology, and estimated acreage value based on prices received for similar, recent acreage transactions by the Company or other market participants. Changes in our assumptions of the estimated nonproductive portion of our undeveloped leases could result in additional impairment expense. During the years ended December 31, 2021, 2020, and 2019, the Company incurred $57.3 million, $37.3 million, and $11.2 million, respectively, in abandonment and impairment of unproved properties.

The partial sale of unproved property is accounted for as a recovery of cost when there is uncertainty of the ultimate recovery of the cost applicable to the interest retained.

Exploratory. Exploratory geological and geophysical, including exploratory seismic studies, and the costs of carrying and retaining unproved acreage are expensed as incurred. Under the successful efforts method of accounting, exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are found, exploratory well costs will be capitalized as proved properties and will be accounted for following the successful efforts method of accounting described above. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. The application of the successful efforts method of accounting requires judgment to determine the proper designation of wells as either development or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that economic proved reserves have been discovered may take considerable time and judgment. Exploratory dry hole costs are included in the cash flows from investing activities section as part of exploration and development of oil and natural gas properties within the accompanying statements of cash flows.

Oil and Natural Gas Reserves. The successful efforts method of accounting outlined above inherently relies on the estimation of proved oil and natural gas reserves. Reserve quantities and the related estimates of future net cash flows are critical inputs in our calculation of units-of-production depletion and our evaluation of proved and unproved properties for impairment. The process of estimating and evaluating crude oil and natural gas reserves is complex, requiring the evaluation of available geological, geophysical, engineering and economic data to estimate underground accumulations of oil and natural gas that cannot be precisely measured. Consequently, the Company engages a third-party petroleum consultant to prepare our estimates of oil and natural gas reserves. Significant inputs and engineering assumptions used in developing the estimates of proved oil and natural gas reserves include reserves volumes, future operating and development costs, historical commodity prices, and the Company’s ability to convert proved undeveloped reserves to producing properties within five years of their initial proved booking.

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, revisions in existing reserve estimates occur. We cannot predict the amounts or timing of such future revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of proved property.

Other Property and Equipment

Other property and equipment such as office furniture and equipment, buildings, and computer hardware and software are recorded at cost. Cost of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed as incurred. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets, which range from three to 25 years.

Leases

The Company determines if an arrangement is representative of a lease at contract inception. Right-of-use (“ROU”) assets represent our right to use the underlying assets for the lease term and the corresponding lease liabilities represent our obligations to make lease payments arising from the leases. Operating and finance lease ROU assets and liabilities are recognized at the lease commencement date based on the present value of the lease payments over the lease term. When evaluating a contract, the Company applies certain judgments to determine, among other factors, lease classification as either operating or financing, lease term, and discount rate. The terms of certain of our leases include options to extend or terminate the lease, only when we can ascertain that it is reasonably certain we will exercise that option, as well as evergreen periods for which the penalties associated with termination are considered to be significant. Leases with an initial term of one year or less are not recorded on the balance sheets. As the Company does not have any leases with an implicit interest rate that can be readily determined, we utilize our incremental borrowing rate based on information available at the lease commencement date in determining the present value of lease payments. We determine our incremental borrowing rate at the lease commencement date using our Credit Facility benchmark rate and make adjustments for facility utilization and lease term. Subsequent measurement, as well as presentation of expenses and cash flows, will depend upon the classification of the lease as either a finance or operating lease. Please refer to *Note 3 - Leases* for additional discussion.

Carbon Offsets

The Company periodically purchases carbon offsets and renewable energy credits as a means to offset carbon emissions generated by its operations that could not otherwise be reduced or eliminated. Commensurate with their use, purchased carbon offsets and renewable energy credits are initially capitalized at cost as an intangible asset within other noncurrent assets on the accompanying balance sheets. Subsequently, capitalized carbon offsets and renewable energy credits are expensed when applied to the Company's carbon emissions through depletion, depreciation, and amortization expense on the accompanying statements of operations. Purchased carbon offsets and renewable energy credits expected to be utilized within the next 12 months are presented as short-term within prepaid expenses and other on the accompanying balance sheets.

Deferred Financing Costs

Deferred financing costs include origination, legal, and other fees incurred to issue debt or amend existing credit facilities. Deferred financing costs related to the Credit Facility are capitalized to prepaid expenses and other and other noncurrent assets on the accompanying balance sheets and amortized to interest expense, net on the accompanying statements of operations on a straight-line basis over the life of the Credit Facility. Deferred financing costs related to senior notes are capitalized within senior notes on the accompanying balance sheets and amortized to interest expense, net on the accompanying statements of operations using the effective interest method over the life of the respective borrowings.

Asset Retirement Obligations

The Company recognizes an asset retirement obligation at fair value based on the present value of costs expected to be incurred in connection with the future abandonment of its oil and natural gas properties, including wells and facilities, in accordance with applicable regulatory requirements. This obligation, and the corresponding capitalized cost recorded to proved properties, is recorded at the time assets are acquired, a well is completed and begins production, or a facility is constructed. The Company recognizes a periodic expense in connection with the accretion of the discounted asset retirement obligation over the remaining estimated economic lives of the respective long-lived assets. The accretion expense is recorded as a component of depreciation, depletion, and amortization in our accompanying statements of operations. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the corresponding capitalized cost recorded to proved properties.

The recognition of an asset retirement obligation requires management to make various assumptions informed by historical experience and applicable regulatory requirements including estimated plugging and abandonment costs, economic lives, inflation rates, and the Company's credit-adjusted risk-free rate.

Cash paid to settle asset retirement obligations is included in the cash flows from operating activities section of the accompanying statements of cash flows. Please refer to *Note 10 – Asset Retirement Obligations* for a reconciliation of the Company's total asset retirement obligation liability as of December 31, 2021 and 2020.

Derivatives

The Company periodically enters into commodity price derivative instruments to mitigate a portion of its exposure to potentially adverse market changes in commodity prices for its expected future oil, natural gas, and NGL production and the associated impact on cash flows. These instruments typically include commodity price swaps and collars, as well as, basis differential and roll differential swaps. The oil instruments are indexed to NYMEX WTI prices, natural gas instruments are indexed to NYMEX HH and CIG prices, and NGL instruments are indexed to OPIS prices, all of which have a high degree of historical correlation with actual prices received by the Company, before differentials.

Presently, our derivative contracts have been executed with 10 counterparties, all but one of which are members of our Credit Facility syndicate. We enter into contracts with counterparties whom we believe are well capitalized and have certain minimum investment grade senior unsecured debt ratings. However, if our counterparties fail to perform their obligations under the contracts, we could suffer financial loss.

Commodity price derivative instruments are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities, with the exception of derivative instruments that meet the "normal purchase normal sale" exclusion. All commodity price derivative instruments are entered into for other-than-trading purposes. The Company does not designate its commodity price derivative contracts as hedging instruments. Accordingly, the Company reflects changes in the fair value of its commodity price derivative instruments in its accompanying statements of operations as they occur. We measure the fair value of our commodity price derivative instruments based upon a pricing model that utilizes market-based inputs, including, but not limited to, contractual price of the underlying position, current market prices, crude oil and natural gas forward curves, discount rates, volatility factors, and nonperformance risk.

As of December 31, 2021 and 2020, all derivative instruments held by the Company were subject to master netting arrangements with various financial institutions. In general, the terms of the Company's agreements provide for offsetting of amounts payable or receivable between it and the counterparty, at the election of both parties, for transactions that settle on the same date and in the same currency. The Company's agreements also provide that in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. The Company's accounting policy is to not offset these positions in its accompanying balance sheets.

Gains and losses on derivatives are included within the cash flows from operating activities section of the accompanying statements of cash flows. Please refer to *Note 9 - Derivatives* for additional discussion.

Revenue Recognition

Revenue is recognized at the point in time when control of produced oil, natural gas, or NGL volumes transfer to the purchaser, which may differ depending on the applicable contractual terms. We consider the transfer of control to have occurred when the purchaser has the ability to direct the use of, and obtain substantially all of the remaining benefits from, the oil, natural gas, or NGL production.

Oil sales. Under the Company's crude purchase and marketing contracts, the Company typically delivers production at the wellhead, or other contractually agreed-upon delivery points, and collects an agreed-upon index price, net of pricing differentials. In this scenario, the Company recognizes revenue when control of its oil production transfers to the purchaser at the wellhead, or other contractually agreed-upon delivery point, at the net contracted price received.

Natural gas and NGL sales. Under the Company's natural gas processing contracts, the Company delivers natural gas to a midstream processing entity at the wellhead, inlet of the midstream processing entity's system, or other contractually agreed-upon delivery points. The delivery points are specified within each contract, and the point at which control transfers varies between the inlet and tailgate of the midstream processing facility. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of NGLs and residue gas.

For the contracts where the Company maintains control through the tailgate of the midstream processing facility, the Company recognizes revenue on a gross basis, with gathering, transportation, and processing fees presented as an expense in the accompanying statements of operations. Alternatively, for those contracts where the Company relinquishes control at the inlet of the midstream processing facility, the Company recognizes natural gas and NGL revenues based on the contracted amount of the proceeds received from the midstream processing entity and, as a result, the Company recognizes revenue on a net basis.

In certain natural gas processing agreements, the Company may elect to take its residue gas and/or NGLs in-kind at the tailgate of the midstream entity's processing plant and subsequently market the product. Through the marketing process, the Company delivers product to the third-party purchaser at a contractually agreed-upon delivery point and receives a specified index price from the third-party purchaser. In this scenario, the Company recognizes revenue when the control transfers to the third-party purchaser at the delivery point based on the index price received from the third-party purchaser. The gathering and processing expense attributable to the natural gas processing contracts, as well as any transportation expense incurred to deliver the product to the third-party purchaser, are presented as gathering, transportation, and processing expense in the consolidated statements of operations.

As noted above, the Company records revenue in the month production is delivered and control is transferred to the purchaser. However, settlement statements and payment may not be received for 30 to 60 days after the date production is delivered and control is transferred. As a result, Company records a revenue accrual based on an estimate of the volumes delivered at estimated prices as determined by the applicable marketing agreements. The Company estimates its sales volumes based on Company-measured volume readings.

The Company records the differences between its estimates and the actual amounts received for product sales in the month in which payment is received from the purchaser. For the year ended December 31, 2021, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was insignificant. At December 31, 2021 and 2020, the Company's receivables from contracts with customers were $362.3 million and $32.7 million, respectively.

As further described in *Note 6 - Commitments and Contingencies*, two contracts have an additional aspect of variable consideration related to the minimum volume commitments ("MVCs") as specified in the agreement. On an on-going basis, the Company performs an analysis of expected risk adjusted production applicable to the agreements based on approved production plans to determine if liquidated damages are probable. As of December 31, 2021, the Company believes that the volumes delivered will be in excess of the MVCs required then and for the upcoming approved production plan. As a result of this analysis, to date, no variable consideration related to potential liquidated damages has been considered in the transaction price for the related agreements.

Revenue attributable to each identified revenue stream is disaggregated below (in thousands):

	Year Ended December 31, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Operating net revenues:			
Oil sales	$ 614,811	$ 174,536	$ 268,865
Natural gas sales	144,708	24,243	28,296
NGL sales	171,095	19,311	16,059
Oil, natural gas, and NGL sales	$ 930,614	$ 218,090	$ 313,220

Stock-Based Compensation

The Company recognizes stock-based compensation based on the grant-date fair value of the equity instruments awarded. Stock-based compensation expense is recognized in the financial statements on a straight-line basis over the requisite service period for the entire award. The Company accounts for forfeitures of stock-based compensation awards as they occur. Please refer to *Note 7 - Stock-Based Compensation* for additional discussion.

Income Taxes

The Company accounts for income taxes under the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the balance sheet or tax returns. Deferred income tax assets and liabilities are measured using enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. If we determine that it is more likely than not that some portion or all of the deferred income tax assets will not be realized, a valuation allowance is recorded, thereby reducing the deferred income tax assets to what is considered to be realizable.

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The Company's policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. There were no uncertain tax positions during any period presented.

The tax returns for 2020, 2019, and 2018 are still subject to audit by the Internal Revenue Service. Please refer to *Note 12 - Income Taxes* for additional discussion.

Earnings Per Share

The Company uses the treasury stock method to determine the effect of potentially dilutive instruments. Please refer to *Note 11 - Earnings Per Share* for additional discussion.

Acreage Exchanges

From time to time, we enter into acreage exchanges in order to consolidate our core acreage positions, enabling us to have more control over the timing of development activities, achieve higher working interests and provide us the ability to drill longer lateral length wells within those core areas. We account for our nonmonetary acreage exchanges in accordance with the guidance prescribed by *Accounting Standards Codification (“ASC”) 845, Nonmonetary Transactions*. For those exchanges that lack commercial substance, we record the acreage received at the net carrying value of the acreage surrendered to obtain it. For those acreage exchanges that are deemed to have commercial substance, we record the acreage received at fair value, with a related gain or loss recognized in earnings, in accordance with *ASC 820, Fair Value Measurement*. During the year ended December 31, 2021, the Company completed non-monetary acreage trades of certain oil and gas properties properties located in Weld County, Colorado. These trades were recorded at carryover basis with no gain or loss recognized.

Business Combinations

As part of our business strategy, we regularly pursue the acquisition of oil and natural gas properties. We utilize the acquisition method to account for acquisitions of businesses. Pursuant to this method, we allocate the cost of the acquisition, or purchase price, to assets acquired and liabilities assumed based on fair values as of the acquisition date. Please refer to *Note 2 - Acquisitions and Divestitures* for additional discussion.

Fair Value of Financial Instruments

The Company’s financial instruments consist of cash and cash equivalents, accounts receivables, and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. As discussed above, the

Company's commodity price derivative instruments are recorded at fair value. The Company's Senior Notes, as defined in *Note 5 – Long-Term Debt*, are recorded at cost, net of any unamortized deferred financing costs, and their respective fair values are disclosed in *Note 8 – Fair Value Measurements*. The recorded value of the Company's Credit Facility approximates its fair value as it bears interest at a floating rate that approximates a current market rate. The Company's warrants were recorded at fair value upon issuance, with no recurring fair value measurement required.

Considerable judgment is required to develop estimates of fair value. The estimates provided are not necessarily indicative of the amounts the Company would realize upon the sale or refinancing of such instruments. Please refer to *Note 8 - Fair Value Measurements* for additional discussion.

Recently Issued and Adopted Accounting Standards

In June 2016, the FASB issued *Update No. 2016-13, Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. The update changes the impairment model for most financial assets and certain other instruments, including trade and other receivables, and requires entities to use a new forward-looking expected loss model that will result in the earlier recognition of allowances for losses. The amended standard was adopted using a modified retrospective approach on January 1, 2020. The Company considered past events (including historical experience), current economic and industry conditions, reasonable and supportable forecasts, and lives of receivable balances and loss experience. Historically and currently, the Company's credit losses on oil and natural gas sales receivables and joint interest receivables have not been significant, and the adoption of this standard did not have a material impact on its consolidated financial statements. As of December 31, 2021 and 2020 the Company had an allowance of $3.7 million and $0.4 million, respectively, established against joint interest receivables.

In August 2018, the FASB issued *Update No. 2018-13, Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement*. The objective of this update is to improve the effectiveness of fair value measurement disclosures. The new standard was adopted on January 1, 2020. The standard only impacted the form of the Company's disclosures.

In March 2020, the FASB issued *Update No. 2020-04, Reference Rate Reform (Topic 848),* which provides temporary optional guidance to companies impacted by the transition away from the LIBOR. The amendment provides certain expedients and exceptions to applying GAAP in order to lessen the potential accounting burden when contracts, hedging relationships, and other transactions that reference LIBOR as a benchmark rate are modified. Further, in January 2021, the FASB issued *Update No. 2021-01, Reference Rate Reform (Topic 848),* which clarifies the scope of Topic 848 so that derivatives affected by the discounting transition are explicitly eligible for certain optional expedients and exceptions in Topic 848. These amendments are effective upon issuance and expire on December 31, 2022. The Company is currently assessing the impact of the LIBOR transition on the Company's consolidated financial statements.

There are no other accounting standards applicable to the Company that would have a material effect on the Company's financial statements and disclosures that have been issued but not yet adopted by the Company as of December 31, 2021, and through the filing date of this report.

NOTE 2 - ACQUISITIONS AND DIVESTITURES

HighPoint Merger

On April 1, 2021, Civitas completed its previously announced acquisition of HighPoint Resources Corporation, a Delaware corporation ("HighPoint"), pursuant to the terms of HighPoint's prepackaged plan of reorganization under Chapter 11 of the United States Bankruptcy Code (the "Prepackaged Plan"), which was confirmed by the U.S. Bankruptcy Court for the District of Delaware on March 18, 2021 pursuant to a confirmation order, and went effective on April 1, 2021 (the "HighPoint Merger").

The Prepackaged Plan implemented the merger and restructuring transactions in accordance with the Agreement and Plan of Merger, dated as of November 9, 2020 (the "HighPoint Merger Agreement"), by and among Civitas, HighPoint and Boron Merger Sub, Inc., a wholly-owned subsidiary of Civitas ("Merger Sub"). Pursuant to the Prepackaged Plan and the HighPoint Merger Agreement, at the effective time of the HighPoint Merger (the "HighPoint Effective Time") and the effective date under the Prepackaged Plan, Merger Sub merged with and into HighPoint, with HighPoint continuing as the surviving corporation and wholly-owned subsidiary of Civitas. At the HighPoint Effective Time, each eligible share of common stock, par value $0.001 per share, of HighPoint issued and outstanding immediately prior to the HighPoint Effective Time was automatically converted into the right to receive 0.11464 shares of common stock, par value $0.01 per share, of Civitas ("Civitas Common Stock"), with cash paid in lieu of the issuance of any fractional shares. As a result, Civitas issued 487,952 shares of Civitas Common Stock to former HighPoint stockholders.

Concurrently with the HighPoint Merger and pursuant to the Prepackaged Plan, and in exchange for the $625.0 million in aggregate principal amount outstanding of 7.0% Senior Notes due 2022 of HighPoint Operating Corporation ("HighPoint OpCo") and 8.75% Senior Notes due 2025 of HighPoint OpCo (collectively, the "HighPoint Senior Notes"), Civitas issued to all holders of HighPoint Senior Notes an aggregate of (i) 9,314,214 shares of Civitas Common Stock and (ii) $100.0 million aggregate principal amount of 7.5% Senior Notes due 2026 ("7.5% Senior Notes"). Please refer to *Note 5 - Long-term Debt* for further discussion of the 7.5% Senior Notes.

Immediately after the HighPoint Effective Time, in connection with the HighPoint Merger, Civitas entered into the Second Amendment, dated April 1, 2021, to the Credit Facility. Please refer to *Note 5 - Long-term Debt* for further discussion.

The following tables present the HighPoint Merger consideration and purchase price allocation of the assets acquired and the liabilities assumed in the HighPoint Merger:

Merger Consideration (in thousands, except per share amount)		
Shares of Civitas Common Stock issued to existing holders of HighPoint Common Stock (1)		488
Shares of Civitas Common Stock issued to existing holders of HighPoint Senior Notes		9,314
Total additional shares of Civitas Common Stock issued as merger consideration		9,802
Closing price per share of Civitas Common Stock (2)	$	38.25
Merger consideration paid in shares of Civitas Common Stock	$	374,933
Aggregate principal amount of the 7.5% Senior Notes		100,000
Total merger consideration	$	474,933

(1) Based on the number of shares of HighPoint Common Stock issued and outstanding as of April 1, 2021 and the conversion ratio of 0.11464 per share of Civitas Common Stock.
(2) Based on the closing stock price of Civitas Common Stock on April 1, 2021.

Purchase Price Allocation (in thousands)

Assets Acquired		
Cash and cash equivalents	$	49,827
Accounts receivable - oil and natural gas sales		26,343
Accounts receivable - joint interest and other		9,161
Prepaid expenses and other		3,608
Inventory of oilfield equipment		4,688
Proved properties		539,820
Other property and equipment, net of accumulated depreciation		2,769
Right-of-use assets		4,010
Deferred income tax assets		110,513
Other noncurrent assets		797
Total assets acquired	$	751,536
Liabilities Assumed		
Accounts payable and accrued expenses	$	51,088
Oil and natural gas revenue distribution payable		20,786
Lease liability		4,010
Derivative liability		18,500
Current portion of long-term debt		154,000
Ad valorem taxes		3,746
Asset retirement obligations		24,473
Total liabilities assumed		276,603
Net assets acquired	$	474,933

The HighPoint Merger was accounted for under the acquisition method of accounting for business combinations. Accordingly, we conducted assessments of the net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisition were expensed as incurred. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market, and therefore represent Level 3 inputs. The fair values of crude oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of proved oil and natural gas properties include estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows, and a market-based weighted-average cost of capital rate of approximately 13%. These inputs require significant judgments and estimates by management at the time of the valuation.

Extraction Merger

Pursuant to the Extraction Merger Agreement, at the effective time of the Extraction Merger (the “Extraction Merger Effective Time”), (i) Raptor Eagle Merger Sub merged with and into Extraction, with Extraction continuing its existence as the surviving corporation as a wholly owned subsidiary of Civitas following the Extraction Merger (the “Extraction Surviving Corporation”), (ii) each share of common stock, par value $0.01 per share, of Extraction (the “Extraction Common Stock”) issued and outstanding as of immediately prior to the Extraction Merger Effective Time was converted into the right to receive 1.1711 shares of Civitas Common Stock for each share of Extraction Common Stock (the “Extraction Exchange Ratio”), with cash paid in lieu of the issuance of fractional shares, if any, and (iii) each holder of Extraction Common Stock received a total dividend equalization payment, as part of the Extraction Merger consideration, of approximately 0.017225678 shares of Civitas Common Stock per share of Extraction Common Stock related to dividends paid to Civitas’ stockholders on June 30, 2021 and September 30, 2021, with cash paid in lieu of the issuance of fractional shares, if any. Following the Extraction Merger and prior to the Crestone Peak Merger (as defined below), persons who were stockholders of Extraction immediately prior to the Extraction Merger owned approximately 50% of the combined company and persons who were stockholders of Civitas immediately prior to the Extraction Merger owned approximately 50% of the combined company.

Additionally, pursuant to the Extraction Merger Agreement, at the Extraction Merger Effective Time, each award of restricted stock units (including those subject to performance-based vesting conditions) issued pursuant to Extraction's 2021 Long Term Incentive Plan (the "Extraction Equity Plan") that was outstanding immediately prior to the Extraction Merger Effective Time and that by its terms did not settle by reason of the occurrence of the closing of the Extraction Merger (each, an "Extraction RSU Award") was assumed by Civitas and converted into a number of restricted stock units with respect to shares (rounded to the nearest number of whole shares) of Civitas Common Stock (such restricted stock unit, a "Converted RSU") equal to the product of the number of Extraction Common Stock subject to the Extraction RSU Award immediately prior to the Extraction Merger Effective Time multiplied by the Extraction Exchange Ratio, effective as of the Extraction Merger Effective Time.

As of the Extraction Merger Effective Time, each Converted RSU continued to be governed by the same terms and conditions (including vesting and forfeiture) that were applicable to the corresponding Extraction RSU Award immediately prior to the Extraction Merger Effective Time. However, any Extraction RSU Award subject to performance-based vesting conditions continued to be measured pursuant to the same terms and conditions of the underlying Extraction RSU Award in effect as of immediately prior to the Extraction Merger Effective Time. In addition, Converted RSUs subject to performance-based vesting conditions held by certain Extraction executives provide that, in the event such individual's employment is terminated for death, disability, by Civitas for any reason other individual for good reason, in each case, on or within twelve months following the Extraction Merger Effective Time, the portion of such individual's Converted RSUs subject to performance-based vesting conditions shall, effective as of such individual's termination date, immediately vest in full based on deemed achievement of any applicable performance goals at the maximum level of performance. Further, effective as of immediately prior to the Extraction Merger Effective Time, each award of deferred stock units granted under the Extraction Equity Plan and held by a member of the Extraction board who was not a designee of Extraction for appointment to Civitas' Board as of the Extraction Merger Effective Time immediately vested in full.

Additionally, at the Extraction Merger Effective Time, in accordance with the terms of (i) the Extraction Tranche A warrants to purchase Extraction Common Stock, issued pursuant to that certain Warrant Agreement by and between Extraction and American Stock Transfer & Trust Company, LLC, as warrant agent ("AST"), dated as of January 20, 2021 (the "Tranche A Warrants"), and (ii) the Extraction Tranche B warrants to purchase Extraction Common Stock, issued pursuant to that certain Warrant Agreement by and between Extraction and AST, as warrant agent, dated as of January 20, 2021 (the "Tranche B Warrants," and, together with the Tranche A Warrants, the "Extraction Warrants"), that were issued and outstanding immediately prior to the Extraction Merger Effective Time, were cancelled and Civitas executed a replacement warrant agreement for the Tranche A Warrants and a replacement warrant agreement for the Tranche B Warrants and issued to each holder of the Extraction Warrants a replacement warrant (each, a "Replacement Warrant") that is exercisable for a number of shares of Civitas Common Stock equal to the number of shares of Civitas Common Stock that would have been issued or paid to a holder of the number of shares of Extraction Common Stock into which such Extraction Warrant was exercisable immediately prior to the Extraction Merger Effective Time. Each Replacement Warrant has an exercise price as set forth in the applicable Replacement Warrant Agreement, subject to adjustment as set forth therein.

The Replacement Warrants may be exercised, in whole or in part, at any time or from time to time on or before 5:00 p.m., New York time, on (i) January 20, 2025, in the case of the Replacement Warrants for the Tranche A Warrants, or (ii) January 20, 2026, in the case of the Replacement Warrants for the Tranche B Warrants. The number of shares of Civitas Common Stock for which a Replacement Warrant is exercisable, and the exercise price of such Replacement Warrant, are subject to customary adjustments from time to time upon the occurrence of certain events, including the payment of in-kind dividends or distributions, splits, subdivisions or combinations of shares of Civitas Common Stock. A holder of a Replacement Warrant, in its capacity as such, is not entitled to any rights whatsoever as a stockholder of Civitas, except to the extent expressly provided in the applicable Replacement Warrant Agreement. 3.4 million Tranche A and 1.7 million Tranche B Replacement Warrants were issued.

The following tables present the merger consideration and preliminary purchase price allocation of the assets acquired and the liabilities assumed in the Extraction Merger:

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Merger Consideration (in thousands, except per share amount)		
Shares of Civitas Common Stock issued as merger consideration[1]		31,095
Closing price per share of Civitas Common Stock[2]	$	56.10
Merger consideration paid in shares of Civitas Common Stock	$	1,744,431
Unvested restricted stock compensation expense as merger consideration	$	19,338
Unvested performance restricted stock compensation expense allocated as merger consideration		2,897
Total merger consideration	$	22,235
Tranche A warrants issued as merger consideration	$	52,164
Tranche B warrants issued as merger consideration		25,299
Total warrant merger consideration	$	77,463
Total merger consideration	$	1,844,129

(1) Based on the number of shares of Extraction Common Stock issued and outstanding as of November 1, 2021 and the conversion ratio of 1.1711 per share of Civitas Common Stock.
(2) Based on the closing stock price of Civitas Common Stock on November 1, 2021.

Preliminary Purchase Price Allocation (in thousands)		
Assets Acquired		
Cash and cash equivalents	$	106,360
Accounts receivable - oil and natural gas sales		119,585
Accounts receivable - joint interest and other		33,054
Prepaid expenses and other		3,044
Inventory of oilfield equipment		9,291
Derivative assets		5,834
Proved properties		1,876,014
Unproved properties		193,400
Other property and equipment, net of accumulated depreciation		40,068
Right-of-use assets		6,883
Deferred income tax assets		49,194
Other noncurrent assets		4,248
Total assets acquired	$	2,446,975
Liabilities Assumed		
Accounts payable and accrued expenses	$	90,353
Production taxes payable		63,572
Oil and natural gas revenue distribution payable		170,002
Income tax payable		14,000
Lease liability		6,883
Derivative liability		100,474
Ad valorem taxes		87,071
Asset retirement obligations		68,741
Other noncurrent liabilities		1,750
Total liabilities assumed		602,846
Net assets acquired	$	1,844,129

The Extraction Merger was accounted for under the acquisition method of accounting for business combinations. Accordingly, we conducted assessments of the net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisition were expensed as incurred. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market, and therefore represent Level 3 inputs. The fair values of crude oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of proved oil and natural gas properties include estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows, and a market-based weighted-average cost of capital rate of approximately 10%. These inputs require significant judgments and estimates by management at the time of the valuation.

The purchase price allocation is preliminary, and Civitas is continuing to assess the fair values of certain of the Extraction assets acquired and liabilities assumed. In particular, assets and liabilities subject to potential adjustment, in amounts that could be material to the pro forma financial statements, include, but are not limited to, proved properties, unproved properties, and accounts payable and accrued expenses related to our continued assessment over the application of lease contracts and related deductions. We cannot reasonably estimate the impact of such conclusions as there is still a high level of uncertainty regarding the underlying terms and application.

Crestone Peak Merger

Pursuant to the Crestone Merger Agreement, at the effective time of the Crestone Peak Merger (the “Crestone Merger Effective Time”), (i) Merger Sub 1 merged with and into Crestone Peak (the “Merger Sub 1 Merger”), with Crestone Peak continuing its existence as the surviving corporation as a wholly owned subsidiary of Civitas following the Merger Sub 1 Merger (the “Crestone Surviving Corporation”), and (ii) subsequently, the Crestone Surviving Corporation merged with and into Merger Sub 2 (the “Merger Sub 2 Merger” and together with the Merger Sub 1 Merger, the “Crestone Peak Merger”), with Merger Sub 2 continuing its existence as the surviving entity as a wholly owned subsidiary of Civitas (the “Crestone Surviving Entity”).

Pursuant to the Crestone Merger Agreement, at the effective time of the Merger Sub 1 Merger (the “Merger Sub 1 Merger Effective Time”), the shares of Crestone Peak common stock, par value $0.01 per share (“Crestone Peak Common Stock”) (excluding shares of Crestone Peak Common Stock held by Crestone Peak as treasury shares or by Civitas or Merger Sub 1 immediately prior to the Merger Sub 1 Merger Effective Time), issued and outstanding as of immediately prior to the Merger Sub 1 Merger Effective Time were converted into the right to collectively receive 22.5 million shares of Civitas Common Stock (the “Crestone Peak Merger Consideration”). In addition, at the effective time of the Merger Sub 2 Merger (the “Merger Sub 2 Merger Effective Time”), each share of common stock of the Crestone Surviving Corporation issued and outstanding as of immediately prior to the Merger Sub 2 Merger Effective Time was automatically cancelled and each unit of Merger Sub 2 issued and outstanding immediately prior to the Merger Sub 2 Merger Effective Time remained issued and outstanding and represents the only outstanding units of the Crestone Surviving Entity immediately following the Merger Sub 2 Merger.

The Crestone Merger Agreement did not provide for specific treatment of equity compensation awards in connection with the Crestone Peak Merger. Certain Crestone Peak employees held profits interests and phantom equity awards based upon the Class B units of Crestone Peak vested in connection with the Crestone Peak Merger under the terms and conditions of the governing equity compensation plans. No employees received settlement payments with respect to any outstanding profits interests, but the outstanding phantom equity awards vested in connection with the Crestone Peak Merger and certain Crestone Peak employees received an aggregate amount of approximately $1.5 million in cash for settlement with respect to the outstanding phantom equity awards in connection with the Crestone Peak Merger.

The following tables present the merger consideration and preliminary purchase price allocation of the assets acquired and the liabilities assumed in the Crestone Peak Merger:

Merger Consideration (in thousands, except per share amount)		
Shares of Civitas Common Stock issued as merger consideration		22,500
Closing price per share of Civitas Common Stock(1)	$	56.10
Merger consideration paid in shares of Civitas Common Stock	$	1,262,250

(1) Based on the closing stock price of Civitas Common Stock on November 1, 2021.

Preliminary Purchase Price Allocation (in thousands)		
Assets Acquired		
Cash and cash equivalents	$	67,505
Accounts receivable - oil and natural gas sales		81,340
Accounts receivable - joint interest and other		9,917
Prepaid expenses and other		2,929
Inventory of oilfield equipment		11,951
Proved properties		1,797,814
Unproved properties		453,321
Other property and equipment, net of accumulated depreciation		7,980
Right-of-use assets		7,934
Total assets acquired	$	2,440,691
Liabilities Assumed		
Accounts payable and accrued expenses	$	134,791
Production taxes payable		52,435
Oil and natural gas revenue distribution payable		83,950
Lease liability		7,934
Derivative liability		338,383
Credit facility		280,000
Ad valorem taxes		66,913
Deferred income tax liabilities		125,086
Asset retirement obligations		88,949
Total liabilities assumed		1,178,441
Net assets acquired	$	1,262,250

The Crestone Peak Merger was accounted for under the acquisition method of accounting for business combinations. Accordingly, we conducted assessments of the net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisition were expensed as incurred. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market, and therefore represent Level 3 inputs. The fair values of crude oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of proved oil and natural gas properties include estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows, and a market-based weighted-average cost of capital rate of approximately 10%. These inputs require significant judgments and estimates by management at the time of the valuation.

The purchase price allocation is preliminary, and Civitas is continuing to assess the fair values of certain of the Crestone Peak assets acquired and liabilities assumed. In particular, assets and liabilities subject to potential adjustment, in amounts that could be material to the pro forma financial statements, include, but are not limited to, proved properties, unproved properties, and accounts payable and accrued expenses related to our continued assessment over the application of lease contracts and related deductions. We cannot reasonably estimate the impact of such conclusions as there is still a high level of uncertainty regarding the underlying terms and application.

Revenue and earnings of the acquiree

The amount of revenue of HighPoint, Extraction, and Crestone Peak included in our statement of operations during the year ended December 31, 2021 was approximately $244.7 million, $172.3 million, and $114.8 million, respectively. We determined that disclosing the amount of HighPoint, Extraction, and Crestone Peak related earnings included in the statements of operation is impracticable, as the operations from these mergers were integrated into the operations of the Company from the dates of each acquisition.

Supplemental pro forma financial information

The following unaudited pro forma financial information (in thousands, except per share amounts) represents a summary of the consolidated results of operations for the year ended December 31, 2021 and 2020, assuming the HighPoint, Extraction, and Crestone Peak mergers had been completed as of January 1, 2020. The pro forma financial information includes certain non-recurring pro forma adjustments that were directly attributable to the business combinations. The pro forma financial information is not necessarily indicative of the results of operations that would have been achieved if the mergers had been effective as of this date, or of future results.

	Year Ended December 31, 2021				
	As reported	HighPoint[1]	Extraction[2]	Crestone Peak[2]	Civitas Pro Forma Combined
Total revenue	$ 930,614	$ 72,019	$ 882,255	$ 508,038	$ 2,392,926
Net income (loss)	178,921	(46,657)	944,814	(299,688)	777,390
Net income per common share - basic	$ 4.82				$ 9.37
Net income per common share - diluted	$ 4.74				$ 9.30

(1) Based on a closing date of April 1, 2021.
(2) Based on a closing date of November 1, 2021.

	Year Ended December 31, 2020				
	As reported	HighPoint	Extraction	Crestone Peak	Civitas Pro Forma Combined
Total revenue	$ 218,090	$ 250,347	$ 557,904	$ 285,426	$ 1,311,767
Net income (loss)	103,528	(1,081,347)	(1,335,406)	(268,057)	(2,581,282)
Net income (loss) per common share - basic	$ 4.98				$ (28.83)
Net income (loss) per common share - diluted	$ 4.95				$ (28.83)

Following the completion of the Extraction Merger and the Crestone Peak Merger, persons who were stockholders of Civitas, Extraction and Crestone Peak immediately prior to the Crestone Peak Merger own approximately 37%, 37% and 26% of the combined company, respectively.

Merger transaction costs of $43.6 million and $6.7 million related to the aforementioned mergers were accounted for separately from the assets acquired and liabilities assumed and are included in merger transaction costs in Civitas' statements of operations for the years ended December 31, 2021 and 2020, respectively.

NOTE 3 - LEASES

The Company's ROU assets and lease liabilities are recognized on the accompanying balance sheets based on the present value of the expected lease payments over the lease term. The following table summarizes the asset classes of the Company's operating and finance leases (in thousands):

	December 31,	
	2021	2020
Operating Leases		
Field equipment[1]	$ 29,312	$ 27,537
Corporate leases	9,484	1,481
Vehicles	1,089	468
Total right-of-use asset	$ 39,885	$ 29,486
Field equipment[1]	$ 29,312	$ 27,537
Corporate leases	9,870	1,900
Vehicles	1,089	468
Total lease liability	$ 40,271	$ 29,905
Finance Leases		
Right of use asset - field equipment[1]	$ —	$ 219
Lease liability - field equipment[1]	$ —	$ 117

(1) Includes compressors, certain natural gas processing equipment, and other field equipment.

The following table summarizes the components of the Company's gross lease costs incurred for the periods below consisted of the following (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Operating lease cost[1]	$ 15,449	$ 13,957	$ 11,330
Finance lease cost			
Amortization of ROU assets	3	18	—
Interest on lease liabilities	1	5	—
Short-term lease cost	3,662	2,058	8,169
Variable lease cost[2]	56	(186)	259
Sublease income[3]	(367)	(358)	(348)
Total lease cost	$ 18,804	$ 15,494	$ 19,410

(1) Includes office rent expense of $2.2 million, $1.1 million, and $1.1 million for the years ended December 31, 2021, 2020, and 2019, respectively.
(2) Variable lease cost represents differences between lease obligations and actual costs incurred for certain leases that do not have fixed payments related to both lease and non-lease components. Such incremental costs include lease payment increases or decreases driven by market price fluctuations and leased asset maintenance costs.
(3) The Company has subleased a portion of one of its office spaces for the remainder of the office lease term.

Lease costs disclosed above are presented on a gross basis. A portion of these costs may have been or will be billed to other working interest owners. The Company's net share of these costs is included in various line items on the accompanying statements of operations or capitalized to proved properties or other property and equipment, as applicable.

The Company recognizes operating lease cost on a straight-line basis. Finance lease cost is recognized based on the effective interest method for the lease liability and straight-line amortization for the right-of-use asset, resulting in more cost being recognized in earlier lease periods. Short-term and variable lease costs are recognized as incurred. Short-term lease cost represents payments for leases with a lease term of one year or less, excluding leases with a term of one month or less. Short-term leases include drilling rigs and other equipment.

The Company's weighted-average remaining lease terms and discount rates as of December 31, 2021 are as follows:

	Operating Leases
Weighted-average lease term (years)	2.7
Weighted-average discount rate	3.9%

Supplemental cash flow information related to leases for the periods below consisted of the following (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 14,284	$ 12,768	$ 10,993
Operating cash flows from finance leases	1	5	—
Financing cash flows from finance leases	21	102	—
Right-of-use assets obtained in exchange for new operating lease obligations	$ 25,469	$ 8,306	$ 16,568
Right-of-use assets obtained in exchange for new finance lease obligations	—	219	—

Future commitments by year for the Company's leases with a lease term of one year or more as of December 31, 2021 are presented in the table below. Such commitments are reflected at undiscounted values and are reconciled to the discounted present value recognized on the accompanying balance sheets as follows (in thousands):

	Operating Leases
2022	$ 20,044
2023	12,980
2024	5,247
2025	1,496
2026	1,178
Thereafter	1,586
Total lease payments	42,531
Less: imputed interest	(2,260)
Total lease liability	$ 40,271

NOTE 4 - OTHER NONCURRENT ASSETS, ACCOUNTS PAYABLE, AND ACCRUED EXPENSES

Other noncurrent assets contain the following (in thousands):

	As of December 31,	
	2021	2020
Deferred financing costs	$ 7,543	$ 725
Operating bonds	3,485	1,641
Carbon offsets	1,967	—
Notes receivable	506	—
AMT credit refund	403	403
Restricted cash	102	102
Other	79	—
Other noncurrent assets	$ 14,085	$ 2,871

Accounts payable and accrued expenses contain the following (in thousands):

	As of December 31,	
	2021	2020
Accounts payable trade	$ 19,623	$ 1,931
Accrued drilling and completion costs	129,430	453
Accrued lease operating expense	19,077	1,793
Accrued general and administrative expense	21,163	4,942
Accrued merger transaction costs	1,475	2,587
Accrued oil and NGL hedging	26,601	—
Accrued interest expense	6,303	322
Accrued settlement	20,791	—
Other accrued expenses	1,725	65
Total accounts payable and accrued expenses	$ 246,188	$ 12,093

NOTE 5 - LONG-TERM DEBT

5.0% Senior Notes

On October 13, 2021, the Company issued $400.0 million aggregate principal amount of 5.0% Senior Notes due 2026 (the "5.0% Senior Notes") pursuant to an indenture, dated October 13, 2021 (the "5.0% Indenture"), among Civitas Resources, the guarantors party thereto and Wells Fargo Bank, National Association, as trustee. Following the closing of the offering, the Company used the net proceeds from the Offering and cash on hand to repay all borrowings under the Credit Facility, all borrowings outstanding under the Crestone Peak credit facility, and for general corporate purposes. Interest accrues at the rate of 5.0% per annum and will be payable semiannually in arrears on April 15 and October 15, commencing on April 15, 2022.

The 5.0% Senior Notes contain covenants that limit, among other things, the Company's ability and the ability of its subsidiaries to: (i) incur or guarantee additional indebtedness; (ii) create liens securing indebtedness; (iii) pay dividends on or redeem or repurchase stock or subordinated debt; (iv) make specified types of investments and acquisitions; (v) enter into or permit to exist contractual limits on the ability of the Company's subsidiaries to pay dividends to Civitas Resources; (vi) enter into transactions with affiliates; (vii) and sell assets or merge with other companies. These covenants are subject to a number of important limitations and exceptions. In addition, certain of these restrictive covenants will be terminated before the 5.0% Senior Notes mature if at any time no default or event of default exists under the 5.0% Indenture and the 5.0% Senior Notes receive an investment-grade rating from at least two ratings agencies. The 5.0% Indenture also contains customary events of default.

At any time prior to October 15, 2023, the Company may redeem the 5.0% Senior Notes, in whole or in part, at a redemption price equal to the sum of (i) the principal amount thereof, plus (ii) the "make-whole" premium at the redemption date, plus (iii) accrued and unpaid interest, if any, to, but excluding, the date of redemption (subject to the right of the noteholders on the relevant record date to receive interest on the relevant interest payment date). On or after October 15, 2023, the Company may redeem all or part of the 5.0% Senior Notes at redemption prices (expressed as percentages of the principal amount redeemed) equal to (i) 102.5% for the twelve-month period beginning on October 15, 2023; (ii) 101.25% for the twelve-month period beginning on October 15, 2024; and (iii) 100.0% for the twelve-month period beginning October 15, 2025 and at any time thereafter, plus accrued and unpaid interest, if any, to, but excluding, the redemption date (subject to the right of the noteholders on the relevant record date to receive interest on the relevant interest payment date).

The Company may redeem up to 35% of the aggregate principal amount of the 5.0% Senior Notes at any time prior to October 15, 2023 with an amount not to exceed the net cash proceeds from certain equity offerings at a redemption price equal to 105.0% of the principal amount of the 5.0% Senior Notes redeemed, plus accrued and unpaid interest, if any, thereon to, but not including, the redemption date, provided, however, that (i) at least 65.0% of the aggregate principal amount of the 5.0% Senior Notes originally issued on the issue date (but excluding 5.0% Senior Notes held by CIVI and its subsidiaries) remains outstanding immediately after the occurrence of such redemption (unless all such 5.0% Senior Notes are redeemed substantially concurrently) and (ii) the redemption occurs within 180 days after the date of the closing of such equity offering.

The 5.0% Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by all of Civitas' existing subsidiaries.

7.5% Senior Notes

In conjunction with the HighPoint Merger, the Company issued $100.0 million aggregate principal amount of 7.5% Senior Notes due 2026 pursuant to an indenture (the "7.5% Indenture"), dated April 1, 2021, by and among Civitas Resources, U.S. Bank National Association ("US Bank"), as trustee, and the subsidiary guarantors party thereto. Interest accrues at the rate of 7.5% per annum and will be payable semiannually in arrears on April 30 and October 31, commencing on October 31, 2021.

The 7.5% Indenture contains restrictive covenants that, among other things, restrict the ability of Civitas Resources, and each of its restricted subsidiaries to: (i) incur additional indebtedness and issue preferred stock; (ii) pay dividends or make other distributions in respect of the Company's common stock; (iii) make other restricted payments and investments; (iv) create liens; (v) restrict distributions or other payments from Civitas' restricted subsidiaries; (v) sell assets, including capital stock of restricted subsidiaries; (vi) merge or consolidate with other entities; and (vii) enter into transactions with affiliates. These restrictive covenants are subject to a number of important qualifications and limitations. In addition, certain of these restrictive covenants will be suspended before the 7.5% Senior Notes mature if at any time no default or event of default exists under the 7.5% Indenture and the 7.5% Senior Notes receive an investment grade rating from at least two ratings agencies. The Indenture also contains customary events of default.

The 7.5% Senior Notes are redeemable at the Company's option (an "Optional Redemption"), in whole or in part, prior to April 30, 2022 at a redemption price equal to 107.5% of the aggregate principal to be redeemed, plus unpaid accrued interest, if any, through the Optional Redemption date. On or after April 30, 2022, the Optional Redemption price will be equal to 100.0% of the aggregate principal amount of the 7.5% Senior Notes to be redeemed, plus unpaid accrued interest, if any, through the Optional Redemption date.

The 7.5% Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by all of Civitas' existing subsidiaries.

The 7.5% Senior Notes and 5.0% Senior Notes are recorded at carrying value. There were no discounts or premiums associated with the either issuance. The table below presents the related carrying values as of December 31, 2021 (in thousands):

	Principal Amount	Unamortized Deferred Financing Costs	Carrying Value
7.5% Senior Notes	$ 100,000	$ —	$ 100,000
5.0% Senior Notes	$ 400,000	$ 8,290	$ 391,710

Credit Facility

In December 2018, the Company entered into a reserve-based revolving facility, as the borrower, with JPMorgan as the administrative agent, and a syndicate of financial institutions, as lenders, that matured on December 7, 2023. The November 2021 redetermination as part of the Amended & Restated Credit Agreement (defined below) resulted in a borrowing base of $1.0 billion, with elected commitments set at $800.0 million. The next scheduled redetermination is set to occur in April 2022.

The Credit Facility contains customary representations and affirmative covenants. The Credit Facility also contains customary negative covenants, which, among other things, and subject to certain exceptions, include restrictions on (i) liens, (ii) indebtedness, guarantees and other obligations, (iii) restrictions in agreements on liens and distributions, (iv) mergers or consolidations, (v) asset sales, (vi) restricted payments, (vii) investments, (viii) affiliate transactions, (ix) change of business, (x) foreign operations or subsidiaries, (xi) name changes, (xii) use of proceeds, letters of credit, (xiii) gas imbalances, (xiv) hedging transactions, (xv) additional subsidiaries, (xvi) changes in fiscal year or fiscal quarter, (xvii) operating leases, (xviii) prepayments of certain debt and other obligations, (xix) sales or discounts of receivables, (xx) dividend payment thresholds, and (xi) cash balances. The Credit Parties are subject to certain financial covenants under the Credit Facility, as tested on the last day of each fiscal quarter, including, without limitation, (a) a maximum ratio of the Company's consolidated indebtedness (subject to certain exclusions) to earnings before interest, income taxes, depreciation, depletion, and amortization, exploration expense, and other non-cash charges (“EBITDAX”) and (b) a current ratio, as defined in the agreement, inclusive of the unused commitments then available to be borrowed, to not be less than 1.00 to 1.

Under the terms of the Credit Facility, as amended in June 2020 (the “First Amendment”), borrowings bore interest at a per annum rate equal to, at the option of the Company, either (i) a LIBOR, subject to a 0% LIBOR floor plus a margin of 2.00% to 3.00%, based on the utilization of the Credit Facility (the “Eurodollar Rate”) or (ii) a fluctuating interest rate per annum equal to the greatest of (a) the rate of interest publicly announced by JPMorgan Chase Bank, N.A. as its prime rate, (b) the rate of interest published by the Federal Reserve Bank of New York as the federal funds effective rate, (c) the rate of interest published by the Federal Reserve Bank of New York as the overnight bank funding rate, or (d) a LIBOR offered rate for a one-month interest period, subject to a 0% LIBOR floor plus a margin of 1.00% to 2.00%, based on the utilization of the Credit Facility (the “Reference Rate”). Interest on borrowings that bear interest at the Eurodollar Rate shall be payable on the last day of the applicable interest period selected by the Company, which shall be one, two, three, or six months, and interest on borrowings that bear interest at the Reference Rate shall be payable quarterly in arrears.

On April 1, 2021, in conjunction with the HighPoint Merger, the Company, together with certain of its subsidiaries, entered into the Second Amendment (the “Second Amendment”) to the Credit Facility (as amended, restated, supplemented or otherwise modified) to, among other things: (i) increase the aggregate maximum commitment amount from $750.0 million to $1.0 billion; (ii) increase the available borrowing base from $260.0 million to $500.0 million; (iii) increase the Eurodollar Rate margin to 3.00% to 4.00%; (iv) increase the Reference Rate margin to 2.00% to 3.00%; (v) increase (A) the LIBOR floor from 0% to .50% and (B) the alternate base rate floor from 0% to 1.50%; (vi) decrease for any fiscal quarter ending on or after April 1, 2021, the maximum permitted net leverage ratio from 3.50 to 3.0; and (viii) amend certain other covenants and provisions.

On November 1, 2021, in conjunction with the Transactions, the Company, as borrower, JPMorgan, as the administrative agent, and a syndicate of financial institutions, as lenders, entered into an Amended and Restated Credit Agreement (the "Amended & Restated Agreement"), dated as of November 1, 2021 having an Aggregate Maximum Credit Amount (as defined in the Amended and Restated Credit Agreement) of $2.0 billion. The Amended and Restated Credit Agreement, among other things: (i) increases the aggregate elected commitments to from $400.0 million to $800.0 million, (ii) increases the available borrowing base from $500.0 million to $1.0 billion, (iii) extends the maturity date of the Amended and Restated Credit Agreement to November 1, 2025 and (iv) amends the borrowing base adjustment provisions such that, between borrowing base determinations, downward adjustments related to the incurrence of certain permitted indebtedness will only occur (x) until the occurrence of the April 2022 borrowing base determination, if such indebtedness exceeds $500.0 million and, (y) thereafter, if either (A) such indebtedness exceeds $500.0 million and the Company's pro-forma leverage ratio is less than or equal to 1.50 to 1, or (B) the Company's pro-forma leverage ratio is greater than 1.50 to 1. Under the Amended and Restated Credit Agreement, the Company's Credit Facility will be guaranteed by all restricted domestic subsidiaries of the Company including by the Extraction Surviving Corporation, the Crestone Surviving Entity, and all their respective subsidiaries, and will be secured by first priority security interests on substantially all assets, including a mortgage on at least 90% of the total value of the proved oil and natural gas properties evaluated in the most recently delivered reserve reports prior to the amendment effective date, including any engineering reports relating to the oil and natural gas properties of the Extraction Surviving Corporation, the Crestone Surviving Entity, their respective subsidiaries, of each of the Company, all restricted domestic subsidiaries of the Company, the Extraction Surviving Corporation and the Crestone Surviving Entity, in each case, subject to customary exceptions.

The Company had zero outstanding on the Credit Facility as of December 31, 2021 and 2020. As of the date of this filing, the outstanding balance was zero. The Company's Credit Facility approximates fair value as the applicable interest rates are floating.

In connection with the Second Amendment and the Amended & Restated Credit Agreement, the Company capitalized a total of approximately $3.9 million and $6.8 million, respectively, in deferred financing costs. Of the total post-amortization net capitalized amounts, (i) $7.5 million and $0.7 million as of December 31, 2021 and 2020, respectively, are presented within other noncurrent assets and (ii) $2.7 million and $0.4 million as of December 31, 2021 and 2020, respectively, are presented within prepaid expenses and other line items in the accompanying balance sheets.

Interest Expense

For the years ended December 31, 2021, 2020, and 2019, the Company incurred interest expense of $16.0 million, $3.8 million, and $5.1 million respectively. The Company capitalized $6.3 million $1.8 million, and $2.4 million of interest expense during the years ended December 31, 2021, 2020, and 2019.

NOTE 6 - COMMITMENTS AND CONTINGENCIES

Legal Proceedings

From time to time, the Company is involved in various commercial and regulatory claims, litigation, and other legal proceedings that arise in the ordinary course of its business. The Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its consolidated financial statements. In accordance with authoritative accounting guidance, an accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the most likely anticipated outcome or the minimum amount within a range of possible outcomes. Because legal proceedings are inherently unpredictable and unfavorable resolutions could occur, assessing contingencies is highly subjective and requires judgments about uncertain future events. When evaluating contingencies, the Company may be unable to provide a meaningful estimate due to a number of factors, including the procedural status of the matter in question, the presence of complex or novel legal theories, and/or the ongoing discovery and development of information important to the matters. The Company regularly reviews contingencies to determine the adequacy of its accruals and related disclosures. No claims have been made, nor is the Company aware of any material uninsured liability which the Company may have, as it relates to any environmental cleanup, restoration, or the violation of any rules or regulations.

Upon closing of the HighPoint, Extraction, and Crestone Peak Mergers, the Company assumed all obligations, whether asserted or unasserted, of HighPoint, Extraction, and Crestone Peak. As of the filing date of this report, there were no probable, material pending, or overtly threatened legal actions against the Company of which it was aware, other than the following:

Boulder County. As of the date of this filing, there is active and ongoing litigation between Boulder County and Extraction which could prevent oil and gas operations for the development minerals contained within Boulder County, Colorado.

Boulder County initiated suit in District Court for Boulder County, Colorado in case no. 2018CV030925 on September 25, 2018, Extraction prevailed before the district court on all issues in an order dated August 29, 2019. The district court's order was appealed, has been fully briefed on appeal, and was argued before the Colorado Court of Appeals on December 14, 2021 - *Board of County Commissioners of Boulder County v. 8 North and Extraction Oil & Gas*, Case No. 2019CA001896 *(Colorado Court of Appeals)*. On March 3, 2022, the Colorado Court of Appeals issued a unanimous opinion rejecting Boulder County's claims. We await whether Boulder will petition the Colorado Supreme Court for certiorari.

This action is primarily a contract case, where the relevant contracts are the CE over the Blue Paintbrush location, Extraction's SUA for the Blue Paintbrush location, and the leases that Boulder owns within the Blue Paintbrush drilling and spacing unit. Boulder seeks invalidation of these leases in the litigation.

Boulder argues that the lease underlying the CE only authorizes the extraction of minerals underneath the CE Property. Boulder takes issue with the planned 32 wells for the location and argues that only the number of wells necessary to extract the minerals underlying the CE property should be allowed. Boulder also argues that Extraction induced a breach of the CE by contracting with the CE property owner for the SUA. Boulder argues that the terms of the SUA violate the CE because the SUA allows for development in excess of that allowed under the underlying lease. Boulder's argument is based on its assertion that the lease underlying the CE property only allows for the extraction of minerals underneath the CE property and ignores that the lease underlying the CE property explicitly allows for pooling and unitization.

Boulder's remaining claims assert that Extraction breached the terms of leases Boulder owns in the drilling and spacing unit by establishing the Blue Paintbrush drilling and spacing unit. Specifically, Boulder's leases within the Blue Paintbrush drilling and spacing unit have a clause that states that a unit must be the "minimum size tract on which a well may be drilled under the laws, rules, or regulations in force at the time of such pooling or unitization." Boulder argues that no drilling and spacing unit including acreage covered by these leases can be greater than 80 acres because COGCC Order 407 established 80-acre drilling and spacing units for the Codell and COGCC Order 407-87 established 80-acre drilling and spacing unit for the Niobrara. In making this argument, Boulder fails to acknowledge that COGCC Rule 318A.l., provides that "…this rule supersedes all prior Commission drilling and spacing orders affecting well location and density requirements of GWA wells. Where the Commission has issued a specific order limiting the number of horizontal wells in a drilling and spacing unit, the well density in such units shall be governed by that order."

An outcome adverse to Extraction, could lead to expiration of our leases in the Blue Paint Brush drilling and spacing unit and impact future, planned locations that include Boulder minerals, result in a decline of our oil and natural gas reserves, or anticipated production volumes.

NOAV. Disclosure of certain environmental matters is required when a governmental authority is a party to the proceedings and the proceedings involve potential monetary sanctions that the Company believes could exceed $0.3 million. The Company has received Notices of Alleged Violations ("NOAV") from the COGCC alleging violations of various Colorado statutes and COGCC regulations governing oil and gas operations. The Company continues to engage in discussions regarding resolution of the alleged violations. As of December 31, 2021, the Company has accrued approximately $1.0 million associated with the NOAVs, as they are probable and reasonably estimable.

Commitments

Firm Transportation Agreements. As part of the HighPoint Merger, the Company became party to two firm transportation contracts. Both firm transportation contracts required the pipeline to provide a guaranteed outlet for production through July 2021. The Company did not utilize the firm capacity on the natural gas pipelines and incurred deficiency payments totaling $7.7 million for the year ended December 31, 2021, which is included in unused commitments expense in the statements of operations.

Additionally, the Company is party to one firm pipeline transportation contract to provide a guaranteed outlet for production on an oil pipeline system. The contract requires the Company to pay minimum volume transportation charges on 8,500 gross barrels per day through April 2022 and 12,500 barrels per day thereafter through April 2025, regardless of the amount of pipeline capacity utilized by the Company. The aggregate financial commitment fee over the remaining term was $47.1 million as of December 31, 2021. The Company expects to utilize most, if not all, of the firm capacity on the oil pipeline system.

Minimum Volume Agreement - Oil. The Company is party to a purchase agreement to deliver fixed determinable quantities of crude oil . This agreement includes defined volume commitments over a term ending in 2023. Under the terms of the agreement, the Company is required to make periodic deficiency payments for any shortfalls in delivering minimum gross volume commitments, which are set in six-month periods. The minimum gross volume commitment will increase approximately 3% each year for the remainder of the contract, to a maximum of approximately 16,000 gross barrels per day.

The aggregate financial commitment fee over the remaining term is $36.4 million as of December 31, 2021. Upon notifying the purchaser at least twelve months prior to the expiration date of the agreement, the Company may elect to extend the term of the agreement for up to three additional years. Since the commencement of the agreement and through the remainder of its term, the Company has not and does not expect to incur any deficiency payments.

Minimum Volume Agreement - Gas and Other. The Company is party to a long-term gas gathering and processing agreement (the "Gathering Agreement") with a third-party midstream provider over a term ending in 2029 with an annual minimum volume commitment of 13.0 Bcf. The Gathering Agreement also includes a commitment to sell take-in-kind NGLs from other processing agreements of 7,500 barrels a day through year seven of the Gathering Agreement with the ability to roll forward up to a 10% shortfall in a given month to the subsequent month. The aggregate financial commitment fee over the remaining term is $151.8 million as of December 31, 2021. The Company has not and does not expect to incur any deficiency payments.

Additionally, the Company is also party to a gas gathering and processing agreement with several third-party producers and a third-party midstream provider to deliver to two different plants over terms that end in August 2025 and July 2026. The Company's share of these commitments requires an incremental 51.5 and 20.6 MMcf per day, respectively, over a baseline volume of 65 MMcf per day for a period of seven years following the in-service dates of the plants. The Company may be required to pay a shortfall fee for any incremental volume deficiencies under these commitments. These contractual obligations can be reduced by the Company's proportionate share of the collective volumes delivered to the plants by other incremental third-party volumes available to the midstream provider that are in excess of the total commitments. Because of the third-party producer reduction provision, we believe that the aggregate financial commitment fee over the remaining term is zero as of December 31, 2021. The Company has not and does not expect to incur any deficiency payments.

The Company is also party to two additional gas gathering and processing agreements as well as a minimum volume commitments to purchase fresh water from water suppliers. These commitments require the Company to pay a fee associated with the minimum volumes regardless of the amount delivered. The aggregate financial commitment fee over the remaining term for these contracts was $15.7 million as of December 31, 2021.

The minimum annual payments under the these agreements for the next five years as of December 31, 2021 are presented below (in thousands):

	Firm Transportation	Minimum Volume[1]
2022	$ 13,064	$ 58,284
2023	14,600	29,192
2024	14,640	22,298
2025	4,800	20,400
2026 and thereafter	—	73,712
Total	$ 47,104	$ 203,886

(1) The above calculation is based on the minimum volume commitment schedule (as defined in the relevant agreement) and applicable differential fees.

Drilling commitments. The Company is party to a drilling commitment agreement with a third-party midstream provider such that the Company is required to drill a total of 106 horizontal wells, whereby a minimum number of wells out of the total must be drilled by a deadline occurring every 2 years over a period ending December 31, 2026. The drilling commitment agreement provides for, among other things, a number of specifications such as minimum consecutive days of production, well performance, and lateral length. Wells operated by others can satisfy this commitment, subject to limitations. If the Company were to fail to complete the wells by the applicable deadline, it would be in breach of the agreement and the third-party midstream provider could attempt to assert damages against Civitas and its affiliates. As of the date of filing, the Company cannot reasonably estimate how much, if any, damages will be paid.

Refer to *Note 3 - Leases* for lease commitments.

NOTE 7 - STOCK-BASED COMPENSATION

Long Term Incentive Plans

In April 2017, the Company adopted the 2017 Long Term Incentive Plan ("2017 LTIP"), which provides for the issuance of restricted stock units, performance stock units, and stock options, and reserved 2,467,430 shares of common stock. In June 2021, the Company adopted the 2021 Long Term Incentive Plan ("2021 LTIP"), which reserved an incremental 700,000 shares of common stock to those previously reserved under the 2017 LTIP. Finally, pursuant to the Extraction Merger Agreement, Civitas assumed the Extraction Equity Plan, which reserved 3,305,080 shares of common stock now issuable by Civitas. The 2017 LTIP, 2021 LTIP, and Extraction Equity Plan are collectively referred to herein as the "LTIP".

In November 2021, the Company adopted a non-employee director compensation program (the "Director Compensation Program"), which provides that non-employee directors will receive grants of deferred stock units ("DSUs"). In connection with the adoption of the Director Compensation Program, the Company adopted a First Amendment to the 2021 LTIP (the "LTIP Amendment") that, among other things, allows the Company to determine whether dividend rights granted pursuant to the LTIP should be reinvested, paid currently or paid in accordance with the terms of an associated award.

The Company records compensation expense associated with the issuance of awards under the LTIP based on the fair value of the awards as of the date of grant within general and administrative expense. The following table outlines the compensation expense recorded by type of award (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Restricted and deferred stock units	$ 11,895	$ 5,283	$ 5,518
Performance stock units	3,663	748	764
Stock options	—	125	604
Total stock-based compensation	$ 15,558	$ 6,156	$ 6,886

As of December 31, 2021, unrecognized compensation expense related to the awards granted under the LTIP will be amortized through the relevant periods as follows (in thousands):

	Unrecognized Compensation Expense	Final Year of Recognition
Restricted and deferred stock units	$ 9,333	2024
Performance stock units	11,192	2024
Total unrecognized stock-based compensation	$ 20,525	

Restricted Stock Units ("RSUs") and Deferred Stock Units

The Company typically grants RSUs to officers, directors, and employees and DSUs to directors as part of its LTIP. Each RSU and DSU represents a right to receive one share of the Company's common stock upon settlement of the award at the end of the specified vesting period.

RSUs generally vest and settle either over a (i) one-year vesting period, with the entire grant vesting and settling on the anniversary date or (ii) three-year vesting period, with one-third of the total grant vesting and settling on each anniversary date. DSUs generally vest in quarterly installments over a one-year period following the grant date. DSUs are settled in shares of the Company's common stock upon the director's separation of service from the Board. The Company records compensation expense associated with the issuance of RSUs and DSUs on a straight-line basis over the vesting period based on the fair value of the awards as of the date of grant within general and administrative expense. The fair value of RSUs and DSUs is equal to the closing price of the Company's common stock on the date of the grant.

A summary of the status and activity of non-vested RSUs and DSUs for the year ended December 31, 2021 is presented below:

	RSUs and DSUs	Weighted-Average Grant-Date Fair Value
Non-vested, beginning of year	550,056	$ 20.30
Granted or assumed	662,748	50.12
Vested	(373,696)	25.61
Forfeited	(24,046)	17.99
Non-vested, end of year	815,062	$ 42.18

The fair value of the RSUs and DSUs granted under the LTIP during the years ended December 31, 2021, 2020, and 2019 was $33.2 million, $4.9 million, and $5.9 million, respectively. Of the total fair value of the RSUs assumed by the Company as a result of the Extraction Merger, $19.3 million was allocated to consideration transferred.

Performance Stock Units ("PSUs")

The Company grants PSUs to officers as part of its LTIP. The number of shares of the Company's common stock issued to settle PSUs ranges from zero to two times the number of PSUs granted and is determined based on performance achievement against certain criteria over a three-year performance period. PSUs generally vest and settle on the third anniversary of the date of the grant.

Dual-criteria PSUs. Performance achievement is determined based on two criteria. The first criterion is based on a comparison of the Company's absolute and relative total shareholder return ("TSR") for the performance period compared with the TSRs of a group of peer companies for the same performance period. The TSR for the Company and each of the peer companies is determined by dividing (A) (i) the volume-weighted average share price for the last 30 trading days of the performance period, plus (ii) dividends paid, minus (iii) the volume-weighted average share price for the 30 trading days preceding the beginning of the performance period, by (B) the volume-weighted average share price for the 30 trading days preceding the beginning of the performance period. The second criterion is based on the Company's annual return on average capital employed ("ROCE") for each year during the three-year performance period. The total number of dual-criteria PSUs granted under the LTIP was split as follows for the relevant grant years:

	2021	2020	2019
TSR	100 %	67 %	50 %
ROCE	— %	33 %	50 %

As these awards depend on a combination of performance-based settlement criteria and market-based settlement criteria, compensation expense may be adjusted in future periods as the number of units expected to vest increases or decreases based on the Company's expected ROCE performance relative to the applicable peer companies.

ATSR PSUs. Performance achievement for the PSUs assumed under the Extraction Equity Plan is determined based on a single criterion based on the Company's annualized absolute total stockholder return ("ATSR"). The ATSR is determined based upon the performance of the Company's common stock relative to a baseline price established at the grant date.

Of the grant-date fair value, the portion of the PSUs tied to the TSR and ATSR performance required a stochastic process method using a Brownian Motion simulation. A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's PSUs tied to TSR and ATSR performance, the Company could not predict with certainty the path its stock price or the stock prices of its peers would take over the performance period. By using a stochastic simulation, the Company created multiple prospective stock pathways, statistically analyzed these simulations, and ultimately made inferences regarding the most likely path the stock price would take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the Brownian Motion Model, was deemed an appropriate method by which to determine the fair value of the portion of the PSUs tied to the TSR and ATSR. Significant assumptions used in this simulation include the Company's expected volatility, risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the performance period, as well as the volatilities for each of the Company's peers.

The following table presents the assumptions used to determine the fair value of the PSUs associated with the market-based settlement criteria as granted under the LTIP:

	Year Ended December 31,		
	2021	2020	2019
TSR			
Expected term (in years)	3	3	3
Risk-free interest rate	0.30 %	0.22 %	2.26 %
Expected daily volatility	3.8 %	3.5 %	2.6 %
ATSR			
Expected term (in years)	2.2		
Risk-free interest rate	0.56 %		
Expected daily volatility	4.7 %		

The fair value of the PSUs granted under the LTIP during the years-ended December 31, 2021, 2020, and 2019, was $15.6 million, $1.9 million, and $2.3 million, respectively. Of the total fair value of the PSUs assumed by the Company as a result of the Extraction Merger, $2.9 million was allocated to consideration transferred.

The PSUs tied to TSR performance granted in 2019 vested as of December 31, 2021, with 200% distribution of shares to the recipients. The PSUs tied to ROCE performance granted in 2019 expired as of December 31, 2021, with zero distribution of shares to the recipients.

A summary of the status and activity of non-vested PSUs for the year ended December 31, 2021 is presented below:

	PSUs (1)	Weighted-Average Grant-Date Fair Value
Non-vested, beginning of year	185,588	$ 22.63
Granted or assumed	177,034	88.13
Vested	(43,255)	32.68
Non-vested, end of year	319,367	$ 57.58

(1) The number of awards assumes that the associated performance condition is met at the target amount. The final number of shares of the Company's common stock issued may vary depending on the performance multiplier, which ranges from zero to two, depending on the level of satisfaction of the performance condition.

Cash flows resulting from excess tax benefits are to be classified as part of cash flows from operating activities. Excess tax benefits are realized tax benefits from tax deductions for vested stock compensation awards in excess of the deferred tax asset attributable to stock compensation costs for such restricted stock. Excess tax benefits recorded RSUs, DSUs, and PSUs that vested during the year ended December 31, 2021 were $0.7 million. The Company recorded no excess tax benefits for the years ended December 31, 2020 and 2019.

Stock Options

The LTIP allows for the issuance of stock options to the Company's employees at the sole discretion of the Board. Options expire ten years from the grant date unless otherwise determined by the Board. Compensation expense on the stock options is recognized as general and administrative expense over the vesting period of the award. There were no stock options granted during 2021, 2020, and 2019.

Stock options are valued using a Black-Scholes Model where expected volatility is based on an average historical volatility of a peer group selected by management over a period consistent with the expected life assumption on the grant date, the risk-free rate of return is based on the U.S. Treasury constant maturity yield on the grant date with a remaining term equal to the expected term of the awards, and the Company's expected life of stock option awards is derived from the midpoint of the average vesting time and contractual term of the awards.

A summary of the status and activity of non-vested stock options for the year ended December 31, 2021 is presented below:

	Stock Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding, beginning of year	72,368	$ 34.36		
Exercised	(46,309)	34.36		
Forfeited	(510)	34.36		
Outstanding, end of year	25,549	$ 34.36	5.0	$ 373
Options outstanding and exercisable	25,549	$ 34.36	5.0	$ 373

The aggregate intrinsic value of options exercised during the year ended December 31, 2021 was $0.7 million.

NOTE 8 - FAIR VALUE MEASUREMENTS

The Company follows authoritative accounting guidance for measuring the fair value of assets and liabilities in its financial statements. This guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Further, this guidance establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available.

The fair value hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1: Quoted prices in active markets for identical assets or liabilities

Level 2: Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable

Level 3: Significant inputs to the valuation model are unobservable

Financial and non-financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, gas, and NGL commodity price derivatives. The fair value of the Company's commodity price derivatives is estimated using industry-standard models that contemplate various inputs including, but not limited to, the contractual price of the underlying position, current market prices, forward commodity price curves, volatility factors, time value of money, and the credit risk of both the Company and its counterparties. We validate our fair value estimate by corroborating the original source of inputs, monitoring changes in valuation methods and assumptions, and reviewing counterparty mark-to-market statements and other supporting documentation. Refer to *Note 9 – Derivatives* for more information regarding the Company's derivative instruments.

The following tables present the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2021 and 2020 and their classification within the fair value hierarchy (in thousands):

	As of December 31, 2021		
	Level 1	Level 2	Level 3
Derivative assets	$ —	$ 3,393	$ —
Derivative liabilities	$ —	$ 239,763	$ —

	As of December 31, 2020		
	Level 1	Level 2	Level 3
Derivative assets	$ —	$ 7,482	$ —
Derivative liabilities	$ —	$ 7,732	$ —

Long-Term Debt

The 7.5% Senior Notes and 5.0% Senior Notes are recorded at cost, net of any unamortized deferred financing costs. The fair value as of December 31, 2021 for the 7.5% Senior Notes and 5.0% Senior Notes was $101.0 million and $404.7 million, respectively. These fair values are based on quoted market prices, and as such, are designated as Level 1 within the fair value hierarchy. The recorded value of the Company's Credit Facility approximates its fair value as it bears interest at a floating rate that approximates a current market rate. Please refer to *Note 5 – Long-Term Debt* for additional information.

Warrants

As discussed in *Note 2 - Acquisitions and Divestitures*, the Company issued warrants in connection with the Extraction Merger. The warrants issued are indexed to the Company's common stock and are required to be net share settled via a cashless exercise. The Company evaluated the warrants under authoritative accounting guidance and determined that they should be classified as equity instruments. The Company's share price traded below the exercise price of the replacement warrants and therefore were not exercisable during the year ended December 31, 2021.

The fair value of the warrants on the issuance date was determined using the Cox-Ross-Rubinstein binomial option pricing model. The warrants were included as a component of merger consideration and are recorded within additional paid-in capital on the accompanying balance sheets at a fair value of $77.5 million, with no recurring fair value measurement required. There have been no changes to the initial carrying amount of the warrants since issuance.

Acquisitions and Impairments of Proved Properties

We utilize the acquisition method to account for acquisitions of businesses. Pursuant to this method, we allocate the cost of the acquisition, or purchase price, to assets acquired and liabilities assumed based on fair values as of the acquisition date. Proved and unproved properties are valued based on a discounted cash flow approach utilizing Level 3 inputs, including, amongst other things, reserve quantities and classification, pace of drilling plans, future commodity prices, future development and lease operating costs, and discount rates using a market-based weighted average cost of capital determined at the time of the acquisition. When estimating the fair value of unproved properties, additional risk-weighting adjustments are applied to probable and possible reserves. Net derivative liabilities assumed are valued based on Level 2 inputs similar to the Company's other commodity price derivatives.

Whenever events or circumstances indicate that the carrying value of proved properties may not be recoverable, the Company uses Level 3 inputs to measure and record impairment at fair value. There were no proved oil and gas property impairments during the years ended December 31, 2021, 2020, and 2019.

NOTE 9 - DERIVATIVES

The Company periodically enters into commodity price derivative instruments to mitigate a portion of its exposure to potentially adverse market changes in commodity prices for its expected future oil, natural gas, and NGL production and the associated impact on cash flows. These instruments typically include commodity price swaps and collars, as well as, basis differential and roll differential swaps. All commodity price derivative instruments are entered into for other-than-trading purposes. The Company does not designate its commodity price derivative contracts as hedging instruments.

In a typical commodity price swap agreement, if the agreed upon published third-party index price is lower than the strike price at the time of settlement, the Company receives the difference between the index price and the agreed upon strike price. If the index price is higher than the agreed upon strike price at the time of settlement, the Company pays the difference. A swaption allows the counterparty, on a specific date, to extend an existing fixed-price swap for a certain period of time or to increase the notional volumes of an existing fixed-price swap.

A collar arrangement establishes a floor and ceiling price on future oil and gas production. When the settlement price is above the ceiling price, the Company pays the difference between the settlement price and the ceiling price. When the settlement price is below the floor price, the Company receives the difference between the settlement price and floor price. In the event that the settlement price is between the ceiling and the floor, no payment or receipt occurs.

A basis differential swap arrangement guarantees a price differential from a specified delivery point to an agreed upon reference point. The Company receives the difference between the price differential and the stated terms, if the price differential is greater than the stated terms. The Company pays the difference between the price differential and the stated terms, if the stated terms are greater than the price differential.

Certain NYMEX calendar month average ("CMA") settlement contracts contain a "CMA Roll Adjustment," the calculation of which includes futures prices for contracts deliverable in, at the time, two forward months. The physical trade month average is compared to the prompt month futures contracts and weighted to reflect the amount of time during the delivery month that the forward months traded as the prompt month. The weighted adjustment values are added to the basic calendar month average to arrive at the Roll Adjusted settlement price for the month. "Oil roll swaps" fix the value of the roll adjustment. If the futures curve becomes more backwardated after entering the oil roll swap, we will pay the difference between the CMA Roll Adjustment and the oil roll swap price. If the futures curve becomes more in contango, we will receive the difference between the CMA Roll Adjustment and the oil roll swap price.

A put gives the owner the right to sell the underlying commodity at a set price over the term of the contract. If the index settlement price is higher than the put fixed price, the put will expire worthless. If the settlement price is lower than the put fixed price, the Company will exercise the put and receive the difference between the settlement price and the put fixed price.

As of December 31, 2021, the Company had entered into the following commodity price derivative contracts:

	Crude Oil (NYMEX WTI)		Natural Gas (NYMEX Henry Hub)		Natural Gas (CIG)		Natural Gas Liquids (OPIS)	
	Bbls/day	Weighted Avg. Price per Bbl	MMBtu/day	Weighted Avg. Price per MMBtu	MMBtu/day	Weighted Avg. Price per MMBtu	Bbls/day	Weighted Avg. Price per Bbl
1Q22								
Collar	15,700	$43.83/$59.77	—	—	20,000	$2.15/$2.75	—	—
Swap	15,371	$47.39	125,170	$2.90	10,000	$2.13	4,000	$20.22
Oil roll swap(1)	2,000	$0.22	—	—	—	—	—	—
2Q22								
Collar	8,800	$38.09/$67.48	60,375	$2.50/$3.50	20,000	$2.15/$2.75	—	—
Swap	10,139	$49.84	53,300	$2.77	10,000	$2.13	4,000	$20.22
Oil roll swap(1)	2,000	$0.22	—	—	—	—	—	—
3Q22								
Collar	7,681	$40.35/$69.99	78,420	$2.59/$3.68	—	—	—	—
Swap	9,359	$46.88	53,300	$2.77	10,000	$2.13	4,000	$20.22
Oil roll swap(1)	2,000	$0.22	—	—	—	—	—	—
4Q22								
Collar	6,938	$40.75/$70.99	76,929	$2.60/$3.69	—	—	—	—
Swap	8,686	$46.77	53,300	$2.77	10,000	$2.13	4,000	$20.22
Oil roll swap(1)	2,000	$0.22	—	—	—	—	—	—
2023								
Collar	260	$40.00/$72.70	2,184	$2.00/$3.25	—	—	—	—
Swap	200	$46.05	43,600	$2.51	—	—	—	—
2024								
Swap	—	—	22,309	$2.57	—	—	—	—

(1) The weighted average differential represents the amount of reduction to NYMEX WTI prices for the notional volumes covered by the swap contracts.

The Company did not enter into any commodity price derivative contracts subsequent to December 31, 2021 through the filing of this report other than those novated from Bison as described in *Note 14 - Subsequent Events.*

Derivative Assets and Liabilities Fair Value

The Company's commodity price derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The following table contains a summary of all the Company's derivative positions reported on the accompanying balance sheets as well as a reconciliation between the gross assets and liabilities and the potential effects of master netting arrangements on the fair value of the Company's commodity derivative contracts as of December 31, 2021 and 2020 (in thousands):

	As of December 31,	
	2021	2020
Derivative Assets:		
Commodity contracts - current	$ 3,393	$ 7,482
Commodity contracts - noncurrent	—	—
Total derivative assets	3,393	7,482
Amounts not offset in the accompanying balance sheets	(3,393)	(4,758)
Total derivative assets, net	$ —	$ 2,724
Derivative Liabilities:		
Commodity contracts - current	$ (219,804)	$ (6,402)
Commodity contracts - long-term	(19,959)	(1,330)
Total derivative liabilities	(239,763)	(7,732)
Amounts not offset in the accompanying balance sheets	3,393	4,758
Total derivative liabilities, net	$ (236,370)	$ (2,974)

The following table summarizes the components of the derivative gain (loss) presented on the accompanying statements of operations for the periods below (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Derivative cash settlement gain (loss):			
Oil contracts	$ (215,057)	$ 50,133	$ 1,185
Gas contracts	(51,806)	(727)	506
NGL contracts	(9,051)	—	—
Total derivative cash settlement gain (loss)(1)	(275,914)	49,406	1,691
Change in fair value gain (loss)	215,404	4,056	(38,836)
Total derivative gain (loss)(1)	$ (60,510)	$ 53,462	$ (37,145)

(1) Total derivative gain (loss) and total derivative cash settlement gain (loss) for each of the periods presented above is reported in the derivative (gain) loss line item and derivative cash settlements gain (loss) line item in the accompanying statements of cash flows, within the cash flows from operating activities.

NOTE 10 - ASSET RETIREMENT OBLIGATIONS

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties, including facilities requiring decommissioning. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is drilled or acquired, or a facility is constructed. The increase in carrying value is included in the proved oil and gas properties line item in the accompanying balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective long-lived assets. Cash paid to settle asset retirement obligations is included in the cash flows from operating activities section of the accompanying statements of cash flows.

The Company's estimated asset retirement obligation liability is based on historical experience plugging and abandoning wells, estimated economic lives, estimated plugging and abandonment cost, and regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised.

A roll-forward of the Company's asset retirement obligation is as follows (in thousands):

	Year Ended December 31,	
	2021	2020
Balance, beginning of year	$ 28,699	$ 27,908
Additional liabilities incurred	183,758	357
Accretion expense	3,933	1,004
Liabilities settled	(4,221)	(2,464)
Revisions to estimate	13,146	1,894
Balance, end of year	$ 225,315	$ 28,699
Current portion	24,000	—
Long-term portion	$ 201,315	$ 28,699

Revisions to estimates for the year ended December 31, 2021 were primarily a result of increases in the Company's estimated plugging and abandonment cost. Revisions to estimates for the year ended December 31, 2020 were primarily a result of increased abandonment costs and decreased estimated economic well lives.

NOTE 11 - EARNINGS PER SHARE

Earnings per basic and diluted share are calculated under the treasury stock method. Basic net income (loss) per common share is calculated by dividing net income (loss) by the basic weighted-average common shares outstanding for the respective period. Diluted net income (loss) per common share is calculated by dividing net income (loss) by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of unvested RSUs, DSUs, PSUs as well as outstanding in-the-money stock options and warrants. When the Company recognizes a loss from continuing operations, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of diluted earnings per share.

The Company issues RSUs and DSUs, which represent the right to receive, upon vesting, one share of the Company's common stock. The number of potentially dilutive shares related to unvested RSUs and DSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the vesting period. The Company issues PSUs, which represent the right to receive, upon settlement of the PSUs, a number of shares of the Company's common stock that ranges from zero to two times the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the performance period applicable to such PSUs. The Company has also issued stock options and warrants, which both represent the right to purchase the Company's common stock at a specified exercise price. The number of potentially dilutive shares related to the stock options and warrants is based on the number of shares, if any, that would be exercisable at the end of the respective reporting period, assuming the date was the end of such stock options' or warrants' term. Stock options and warrants are only dilutive when the average price of the common stock during the period exceeds the exercise price. Please refer to *Note 7 - Stock-Based Compensation* for additional discussion.

The following table sets forth the calculations of basic and diluted net income per common share (in thousands, except per share amounts):

	Year Ended December 31,		
	2021	2020	2019
Net income	$ 178,921	$ 103,528	$ 67,067
Basic net income per common share	$ 4.82	$ 4.98	$ 3.25
Diluted net income per common share	$ 4.74	$ 4.95	$ 3.24
Weighted-average shares outstanding - basic	37,155	20,774	20,612
Add: dilutive effect of contingent stock awards	591	138	69
Weighted-average shares outstanding - diluted	37,746	20,912	20,681

There were 178,051, 248,744, and 269,208 shares that were anti-dilutive for the years ended December 31, 2021, 2020, and 2019 respectively.

NOTE 12 - INCOME TAXES

Deferred tax assets and liabilities are measured by applying the provisions of enacted tax laws to determine the amount of taxes payable or refundable currently or in future years related to cumulative temporary differences between the tax basis of assets and liabilities and amounts reported in the accompanying balance sheets. The tax effect of the net change in the cumulative temporary differences during each period in the deferred tax assets and liabilities determines the periodic provision for deferred taxes.

The provision for income taxes consists of the following (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Current tax expense (benefit)			
Federal	$ —	$ (27)	$ —
State	—	—	—
Total current tax expense (benefit)	—	(27)	—
Deferred tax expense (benefit)			
Federal	62,212	(53,784)	—
State	10,646	(6,736)	—
Total deferred tax expense (benefit)	72,858	(60,520)	—
Total income tax expense (benefit)	$ 72,858	$ (60,547)	$ —

Temporary differences between the financial statement carrying amounts and tax basis of assets and liabilities that give rise to the net deferred tax asset result from the following components (in thousands):

	As of December 31,	
	2021	2020
Deferred tax liabilities:		
Oil and gas properties	$ 608,829	$ 89,867
Right-of-use assets	8,292	7,306
Total deferred tax liabilities	617,121	97,173
Deferred tax assets:		
Federal and state tax net operating loss carryforward	482,216	138,372
Derivative instruments	86,958	61
Reclamation costs	51,515	7,058
Stock compensation	7,622	1,653
Inventory	10,108	1,598
Lease liability	8,187	7,384
Property taxes	19,458	—
Pending acquisition costs	—	1,478
Other long-term assets	21,474	89
Total deferred tax assets	687,538	157,693
Less: Valuation allowance	48,133	—
Total deferred tax assets after valuation allowance	639,405	157,693
Total non-current net deferred tax asset	$ 22,284	$ 60,520

On April 1, 2021, the Company completed the HighPoint Merger. For federal income tax purposes we acquired carryover tax basis in HighPoint's assets and liabilities, including $219.0 million of federal net operating loss carryforwards. We recorded a net deferred tax asset of $110.5 million as part of the business combination accounting for HighPoint. The net operating loss carryforwards and other tax attributes will be subject to an annual limitation under Section 382 of the Code of approximately $5.6 million. We determined that a separate valuation allowance of $48.1 million was required to be established through business combination accounting against the deferred tax assets acquired.

On November 1, 2021, the Company completed the Extraction Merger. For federal income tax purposes we acquired carryover tax basis in Extraction's assets and liabilities, including $479.9 million of federal net operating loss carryforwards. We recorded a net deferred tax asset of $49.2 million as part of the business combination accounting for Extraction. The net operating loss carryforwards will be subject to an annual limitation under Section 382 of the Code of approximately $7.0 million. We determined that no separate valuation allowance was required to be established through business combination accounting against the deferred tax assets acquired.

On November 1, 2021, the Company completed the Crestone Peak Merger. For federal income tax purposes we acquired carryover tax basis in Crestone Peak's assets and liabilities, including $555.7 million of federal net operating loss carryforwards. We recorded a net deferred tax liability of $125.1 million as part of the business combination accounting for Crestone Peak. The net operating loss carryforwards will be subject to an annual limitation under Section 382 of the Code of approximately $16.8 million. We determined that no separate valuation allowance was required to be established through business combination accounting against the deferred tax assets acquired.

The Company has $2.0 billion and $579.4 million of net operating loss carryovers for federal income tax purposes as of December 31, 2021 and 2020, respectively. The significant increase in net operating loss carryovers resulted from the HighPoint, Extraction, and Crestone Peak mergers as discussed above. Due to change of ownership provisions of Section 382 of the Code, utilization of these acquired net operating loss carryovers and other tax attributes may be limited. Federal net operating loss carryforwards incurred prior to January 1, 2018 of $696.3 million will begin to expire in 2034. Federal net operating loss carryforwards incurred after December 31, 2017 of $1.3 billion have no expiration and can only be used to offset 80% of taxable income when utilized.

The Company assesses the recoverability of its deferred tax assets each period by considering whether it is more likely than not that all or a portion of the deferred tax assets will be realized. In making such determination, the Company considers all available (both positive and negative) evidence, including future reversals of temporary differences, tax-planning strategies, projected future taxable income, and results of operations. On the basis of this evaluation, the Company recorded a valuation allowance of $72.6 million on its net deferred tax assets as of December 31, 2019, which was removed in 2020. During 2021, as a result of the HighPoint Merger, the Company recorded a valuation allowance of $48.1 million against certain acquired net operating losses and other tax attributes due to the limitation on realizability caused by the change of ownership provisions of Section 382 of the Code. The Company will continue to monitor facts and circumstances in the reassessment of the likelihood that the deferred tax assets will be realized.

Federal income tax expense differs from the amount that would be provided by applying the statutory United States federal income tax rate of 21% to income before income taxes primarily due to the effect of state income taxes, changes in valuation allowances, rate changes, and other permanent differences, as follows (in thousands):

	Year Ended December 31,		
	2021	**2020**	**2019**
Federal statutory tax expense	$ 52,824	$ 9,026	$ 14,084
Increase (decrease) in tax resulting from:			
State tax expense net of federal benefit	10,646	1,694	2,537
Prior year true-up	27	292	(579)
Stock compensation	(1,559)	690	197
Permanent differences	84	36	128
State rate change	—	124	—
Transaction costs	9,043	—	—
Section 162(m) limitation	1,793	144	156
Valuation allowance	—	(72,553)	(16,523)
Total income tax expense (benefit)	$ 72,858	$ (60,547)	$ —

During the year ended December 31, 2021, the increase in tax rate was primarily due to non-deductible transaction costs incurred in connection with the HighPoint, Extraction, and Crestone Peak mergers, along with net income increasing between the comparable periods. There was $72.9 million of deferred income tax expense in the accompanying statements of operations.

During the year ended December 31, 2020, the decrease in tax rate was primarily due to fully removing the valuation allowance against net deferred tax assets and net income decreasing between the comparable periods. There was $60.5 million of deferred income tax benefit in the accompanying statements of operations. The valuation allowance decreased by $72.6 million to zero in 2020 when compared to the same period in 2019 due to both current and forecasted book income.

During the year ended December 31, 2019, there were no deferred income tax benefits or expense in the accompanying statements of operations. The valuation allowance decreased by $16.5 million to $72.6 million in 2019 when compared to the same period in 2018. The Company's net income decreased between the comparable periods causing the federal tax benefit to decrease.

The Company had no unrecognized tax benefits as of December 31, 2021, 2020, and 2019. The tax returns for 2020, 2019, and 2018 are still subject to audit by the Internal Revenue Service.

NOTE 13 - DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The Company's oil and natural gas activities are located entirely within the United States. Costs incurred in oil and natural gas producing activities are as follows (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Acquisition[1]	$ 4,861,619	$ 11,296	$ 12,901
Development[2][3]	315,746	55,934	209,535
Exploration	7,937	595	796
Total	$ 5,185,302	$ 67,825	$ 223,232

(1) Acquisition costs for unproved properties for the years ended December 31, 2021, 2020, and 2019 were $648.0 million, $2.3 million, and $4.2 million, respectively. There were $4.2 billion, $9.0 million, and $8.7 million in acquisition costs for proved properties for the years ended December 31, 2021, 2020, and 2019, respectively.
(2) Development costs include workover costs of $2.2 million, $1.2 million, and $1.4 million charged to lease operating expense for the years ended December 31, 2021, 2020, and 2019, respectively.
(3) Includes amounts relating to asset retirement obligations of $13.8 million, $(1.0) million, and $(0.9) million, for the years ended December 31, 2021, 2020, and 2019, respectively.

Suspended Well Costs

The Company did not incur any exploratory well costs during the years ended December 31, 2021, 2020, and 2019.

Reserves

The proved reserve estimates were prepared by our third party independent reserve engineers, which were Ryder Scott at December 31, 2021 and 2020 and NSAI for the estimates at December 31, 2019. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes, and other factors.

All of the Company's oil, natural gas liquids, and natural gas reserves are attributable to properties within the United States. A summary of the Company's changes in quantities of proved oil, natural gas liquids, and natural gas reserves for the years ended December 31, 2021, 2020, and 2019 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)
Balance-December 31, 2018	64,354	165,012	24,930
Extensions, discoveries and infills(1)	8,825	20,604	3,123
Production	(5,136)	(11,967)	(1,431)
Sales of minerals in place	(52)	(110)	(18)
Removed from capital program(2)	(4,926)	(11,508)	(1,862)
Purchases of minerals in place	303	627	102
Revisions to previous estimates(3)	1,045	49,542	(2,683)
Balance-December 31, 2019	64,413	212,200	22,161
Extensions, discoveries and infills(1)	9,376	32,172	3,269
Production	(5,019)	(14,166)	(1,858)
Removed from capital program(2)	(14,120)	(33,886)	(3,141)
Purchases of minerals in place	1,430	5,457	570
Revisions to previous estimates(3)	(3,287)	33,951	5,110
Balance-December 31, 2020	52,793	235,728	26,111
Extensions, discoveries and infills(1)	19	103	—
Production	(4,523)	(13,852)	(1,763)
Removed from capital program(2)	(12,249)	(43,918)	(4,485)
Purchases of minerals in place	114,379	767,504	89,797
Revisions to previous estimates(3)	(6,840)	(57,066)	(3,632)
Balance-December 31, 2021	143,579	888,499	106,028
Proved developed reserves:			
December 31, 2019	25,397	105,840	11,566
December 31, 2020	24,320	123,220	14,315
December 31, 2021	104,078	748,762	88,967
Proved undeveloped reserves:			
December 31, 2019	39,016	106,360	10,595
December 31, 2020	28,473	112,508	11,796
December 31, 2021	39,501	139,737	17,061

(1) During the years ended December 31, 2021, 2020, and 2019, horizontal development in the Wattenberg Field resulted in additions in extensions, discoveries, and infills of nominal MMBoe, 18.0 MMBoe, and 15.4 MMBoe, respectively.

(2) During the years ended December 31, 2021, 2020, and 2019, proved undeveloped reserves were reduced by 24.1 MMBoe, 22.9 MMBoe, and 8.7 MMBoe respectively, primarily due to the removal of proved undeveloped locations from our five-year drilling program.

(3) As of December 31, 2021, the Company revised its proved reserves downward by 20.0 MMBoe primarily driven by 13.1 MMBoe in negative revisions due to changes in well operating cost methodology, 6.9 MMBoe in negative engineering revisions, and 7.1 MMBoe in negative revisions for fuel gas, interest, shrink, and other minor revisions. The commodity prices at December 31, 2021 increased to $66.56 per Bbl WTI and $3.60 per MMBtu HH from $39.57 per Bbl WTI and $1.99 per MMBtu HH at December 31, 2020, resulting in a partially offsetting positive revision of 7.1 MMBoe.

As of December 31, 2020, the Company revised its proved reserves upward by 7.5 MMBoe primarily driven by 12.3 MMBoe in positive engineering revisions. The commodity prices at December 31, 2020 decreased to $39.57 per Bbl WTI and $1.99 per MMBtu HH from $55.85 per Bbl WTI and $2.58 per MMBtu HH at December 31, 2019, resulting in a partially offsetting negative revision of 4.8 MMBoe.

As of December 31, 2019, the Company revised its proved reserves upward by 6.6 MMBoe. The commodity prices at December 31, 2019 decreased to $55.85 per Bbl WTI and $2.58 per MMBtu HH from $65.56 per Bbl WTI and $3.10 per MMBtu HH at December 31, 2018, resulting in a negative revision of 1.4 MMBoe, offset by 8.1 MMBoe in positive engineering revision.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with accounting authoritative guidance. Future cash inflows were computed by applying prices to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year-end, based on current costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves. Future income tax expenses give effect to permanent differences, tax credits, and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of the Company's oil and natural gas properties.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Future cash flows	$ 14,401,814	$ 2,230,012	$ 3,827,009
Future production costs	(5,054,695)	(675,755)	(1,029,140)
Future development costs	(1,107,576)	(530,970)	(850,327)
Future income tax expense	(1,465,949)	—	—
Future net cash flows	6,773,594	1,023,287	1,947,542
10% annual discount for estimated timing of cash flows	(2,361,490)	(586,233)	(1,089,395)
Standardized measure of discounted future net cash flows	$ 4,412,104	$ 437,054	$ 858,147

Future cash flows as shown above were reported without consideration for the effects of derivative transactions outstanding at period end.

The changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Beginning of period	$ 437,054	$ 858,147	$ 954,980
Sale of oil and gas produced, net of production costs	(773,711)	(160,466)	(233,677)
Net changes in prices and production costs	874,155	(641,137)	(372,233)
Net changes in extensions, discoveries and improved recoveries	855	(54,269)	45,728
Development costs incurred	108,113	42,325	185,086
Changes in estimated development cost	106,788	220,964	81,358
Purchases of minerals in place	4,484,125	12,372	10,135
Sales of minerals in place	—	—	(309)
Revisions of previous quantity estimates	(84,126)	60,754	79,637
Net change in income taxes	(915,053)	—	—
Accretion of discount	43,705	85,815	95,498
Changes in production rates and other	130,199	12,549	11,944
End of period	$ 4,412,104	$ 437,054	$ 858,147

The average wellhead prices used in determining future net revenues related to the standardized measure calculation as of December 31, 2021, 2020, and 2019 were calculated using the twelve-month arithmetic average of first-day-of-the-month prices inclusive of adjustments for quality and location.

	Year Ended December 31,		
	2021	2020	2019
Oil (per Bbl)	$ 61.60	$ 34.96	$ 51.22
Gas (per Mcf)	$ 2.60	$ 0.95	$ 1.44
Natural gas liquids (per Bbl)	$ 30.60	$ 6.12	$ 10.07

NOTE 14 - SUBSEQUENT EVENTS

On January 31, 2022, the Company signed definitive agreements to acquire privately held DJ Basin operator Bison Oil & Gas II, LLC (“Bison”) for approximately $346 million of consideration, including the assumption of approximately $176 million in debt and other liabilities. On February 27, 2022, the Company and Bison entered into an amendment to the definitive agreements signed on January 31, 2022 to, among other things, increase the aggregate cash consideration paid to Bison from $45 million to $160 million and eliminate the previously contemplated share consideration. The transaction closed on March 1, 2022.

As of March 1, 2022, the following commodity price derivative contracts were novated from Bison:

	Crude Oil (NYMEX WTI)		Natural Gas (NYMEX Henry Hub)	
	Bbls/day	Weighted Avg. Price per Bbl	MMBtu/day	Weighted Avg. Price per MMBtu
2022[(1)]				
Collar[(2, 3)]	2,756	\$47.85 / \$56.71	2,278	\$2.67 / \$3.39
Swap	873	\$47.38	1,582	\$2.52
2023				
Collar[(2, 3)]	1,406	\$48.62 / \$57.71	1,828	\$2.36 / \$2.98
Swap	208	\$46.47	470	\$2.51
2024				
Collar[(2, 3)]	143	\$45.00 / \$56.25	1,337	\$2.40 / \$3.15
Swap	479	\$53.96	—	—

(1) Represents hedged volumes from the closing date through December 31, 2022.
(2) 79%, 100%, and 100% of the 2022, 2023, and 2024 oil collars presented include sold puts at a weighted average price of \$38.72, \$38.38, and \$35.00 per Bbl, respectively
(3) 5%, 19%, and 23% of the 2022, 2023, and 2024 gas collars presented include sold puts at a weighted average price of \$2.00 per MMBtu, respectively.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*.

None.

Item 9A. *Controls and Procedures*.

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2021. The term “disclosure controls and procedures,” as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized, and reported, within the time periods specified in SEC rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the company’s management, including its principal executive and principal financial officers and internal audit function, as appropriate to allow timely decisions regarding required disclosure. Based on the evaluation of our disclosure controls and procedures as of December 31, 2021, our principal executive officer and principal financial officer concluded that, as of such date, our disclosure controls and procedures were effective at the reasonable assurance level.

Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving their objectives and management necessarily applies its judgment in evaluating the cost-benefit relationship of possible controls and procedures. To assist management, we have established an internal audit function to verify and monitor our internal controls and procedures. The Company’s internal control system is supported by written policies and procedures, contains self-monitoring mechanisms, and is audited by the internal audit function. Appropriate actions are taken by management to correct deficiencies as they are identified.

Management’s Assessment of Internal Control Over Financial Reporting

The Company’s management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). The Company’s internal control over financial reporting is a process designed under the supervision of the Company’s Chief Executive Officer and Principal Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States. 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 the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or processes may deteriorate.

As of December 31, 2021, management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control-Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on the assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2021. Management included in its assessment of internal control over financial reporting all consolidated entities.

Deloitte & Touche LLP, the independent registered public accounting firm that audited the consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2021, which is included in the consolidated financial statements in Item 8, Part II of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during the quarter ended December 31, 2021 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Civitas Resources, Inc. (formerly Bonanza Creek Energy, Inc.)

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Civitas Resources, Inc. (formerly Bonanza Creek Energy, Inc.) and subsidiaries (the "Company") as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2021, of the Company and our report dated March 8, 2022, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

/s/ Deloitte & Touche LLP

Denver, Colorado
March 8, 2022

Item 9B. ***Other Information*.**

None.

Item 9C. ***Disclosure Regarding Foreign Jurisdictions that Prevent Inspections***

Not applicable.

PART III

Item 10. ***Directors, Executive Officers, and Corporate Governance*****.**

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2021.

Our Board has adopted a Code of Business Conduct and Ethics applicable to all officers, directors, and employees, which is available on our website (www.civitasresources.com) under “Corporate Governance” under the “For Investors” tab. We will provide a copy of this document to any person, without charge, upon request by writing to us at Civitas Resources, Inc., Investor Relations, 555 17th Street, Suite 3700, Denver, Colorado 80202. We intend to satisfy the disclosure requirement under Item 406(c) of Regulation S-K regarding an amendment to, or waiver from, a provision of our Code of Business Conduct and Ethics by posting such information on our website at the address and the location specified above.

Item 11. ***Executive Compensation*****.**

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2021.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*****.**

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2021.

Item 13. ***Certain Relationships and Related Transaction and Director Independence*****.**

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2021.

Item 14. ***Principal Accounting Fees and Services (PCAOB ID No. 34).***

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2021.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules.***

(a) The following documents are filed as a part of this Annual Report on Form 10-K or incorporated herein by reference:

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of November 9, 2020, by and among Bonanza Creek Energy, Inc., Boron Merger Sub, Inc. and HighPoint Resources Corporation (incorporated by reference to Exhibit 2.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on November 9, 2020)
2.2	Amendment No. 1 to the Agreement and Plan of Merger, by and among Bonanza Creek Energy, Inc., Boron Merger Sub, Inc. and HighPoint Resources Corporation, dated as of January 29, 2021 (incorporated by reference to Exhibit 2.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on February 1, 2021)
2.3	Agreement and Plan of Merger, dated as of May 9, 2021, by and among Bonanza Creek Energy, Inc., Raptor Eagle Merger Sub, Inc. and Extraction Oil & Gas, Inc. (incorporated by reference to Exhibit 2.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on May 10, 2021).
2.4	Agreement and Plan of Merger, dated as of June 6, 2021, by and among Bonanza Creek Energy, Inc., Raptor Condor Merger Sub 1, Inc., Raptor Condor Merger Sub 2, LLC, Crestone Peak Resources LP, CPPIB Crestone Peak Resources America Inc., Crestone Peak Resources Management LP and Extraction Oil & Gas, Inc. (incorporated by reference to Exhibit 2.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on June 8, 2021).
2.5	Amendment No.1 to Agreement and Plan of Merger, dated as of June 6, 2021, by and among Bonanza Creek Energy, Inc., Raptor Eagle Merger Sub, Inc. and Extraction Oil & Gas, Inc. (incorporated by reference to Exhibit 2.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on June 8, 2021).
3.1	Third Amended and Restated Certificate of Incorporation of Bonanza Creek Energy, Inc. (incorporated by reference to Exhibit 3.1 to Bonanza Creek Energy, Inc.'s Registration Statement on Form 8-A filed on April 28, 2017)
3.2	Certificate of Amendment to the Third Amended and Restated Certificate of Incorporation of Bonanza Creek Energy, Inc. (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on November 3, 2021).
3.3	Fifth Amended and Restated Bylaws of Civitas Resources, Inc. (incorporated by reference to Exhibit 3.2 to Civitas Resources, Inc.'s Current Report on Form 8-K, File No. 001-35371, filed on November 3, 2021).
3.4	Certificate of Elimination of Series A Junior Participating Preferred Stock of Civitas Resources, Inc. (incorporated by reference to Exhibit 3.3 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
4.1	Description of Capital Stock
4.2	Indenture, dated as of April 1, 2021, by and among Bonanza Creek Energy, Inc., U.S. Bank National Association, as trustee, and the subsidiary guarantors party thereto (incorporated by reference to Exhibit 4.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 1, 2021).
4.3	First Supplemental Indenture, dated as of April 1, 2021, by and among Bonanza Creek Energy, Inc., U.S. Bank National Association, as trustee, HighPoint Resources Corporation, HighPoint Operating Corporation and Fifth Pocket Productions, LLC (incorporated by reference to Exhibit 4.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 1, 2021).
4.4	Indenture, dated as of October 13, 2021, by and among Bonanza Creek Energy, Inc., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on October 15, 2021).
4.5	First Supplemental Indenture, dated as of November 1, 2021, by and among Civitas Resources, Inc., Computershare Trust Company, N.A., as trustee, and certain guarantor parties thereto (incorporated by reference to Exhibit 4.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).

4.6	Second Supplemental Indenture, dated as of November 1, 2021, by and among Civitas Resources, Inc., U.S. Bank National Association, as trustee, and certain guarantor parties thereto (incorporated by reference to Exhibit 4.2 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
4.7	Confirmation Order, filed March 18, 2021 (incorporated by reference to Exhibit 99.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on March 22, 2021).
10.1	Tranche A Warrant Agreement, dated November 1, 2021, between Civitas Resources, Inc. and Broadridge Corporate Issuer Solutions, Inc. (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.2	Tranche B Warrant Agreement, dated November 1, 2021, between Civitas Resources, Inc. and Broadridge Corporate Issuer Solutions, Inc. (incorporated by reference to Exhibit 10.2 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.3	Registration Rights Agreement, dated April 1, 2021, between Bonanza Creek Energy, Inc., and Franklin Advisers, Inc. (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 1, 2021).
10.4	Registration Rights Agreement, dated as of May 9, 2021, by and between Bonanza Creek Energy, Inc. and Kimmeridge Chelsea, LLC (incorporated by reference to Exhibit 4.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on May 10, 2021).
10.5	Registration Rights Agreement, dated November 1, 2021, between Civitas Resources, Inc., and the persons identified on Schedule I thereto (incorporated by reference to Exhibit 10.7 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.6*	Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017).
10.7*	Form of Non-Qualified Stock Option Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017).
10.8*	Form of Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017).
10.9*	Form of Officer Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on May 22, 2018).
10.10*	Form of Independent Director Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on November 6, 2019).
10.11*	Form of Performance Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on May 22, 2018)
10.12*	Form of Officer Performance Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on August 9, 2021).
10.13*	Form of NYSE Inducement Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 5, 2018).
10.14*	Bonanza Creek Energy, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.6 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on August 9, 2021).
10.15*	First Amendment to the Bonanza Creek Energy, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.11 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.16*	Form of Independent Director Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on August 9, 2021).
10.17*	Form of Officer Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.8 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on October 28, 2021).

10.18*	Form of Non-Officer Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on October 28, 2021).
10.19*	Extraction Oil & Gas, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.6 to Extraction's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on January 20, 2021).
10.20*	Form of Restricted Stock Unit (RSU) Agreement (Time and Performance Vesting) (incorporated by reference to Exhibit 10.7 to Extraction Oil & Gas, Inc.'s Current Report on Form 8-K filed on January 20, 2021).
10.21*	Civitas Resources, Inc. Eighth Amended and Restated Executive Change in Control and Severance Benefit Plan (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on January 25, 2022).
10.22*	Form of Indemnity Agreement between Civitas Resources, Inc. and the directors and executive officers of Civitas Resources, Inc. (incorporated by reference to Exhibit 10.9 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.23*	Employment Letter Agreement dated June 20, 2019 between Bonanza Creek Energy, Inc. and Sandra Garbiso (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on June 20, 2019).
10.24*	Form of Officer Employment/Promotion Letter Agreement (incorporated by references to Exhibit 10.22 to Bonanza Creek Energy, Inc.'s Annual Report on Form 10-K filed February 28, 2020)
10.25	Amended and Restated Credit Agreement, dated as of November 1, 2021, between Civitas Resources, Inc., as borrower, JPMorgan Chase Bank, N.A., as the administrative agent, and a syndicate of financial institutions, as lenders (incorporated by reference to Exhibit 10.5 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.26	First Amendment to Amended and Restated Credit Agreement, among Civitas Resources, Inc., the guarantors party thereto, the lenders party thereto and JPMorgan Chase Bank, N.A., as the administrative agent (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on December 22, 2021).
10.27	Letter Agreement, dated as of May 19, 2021, by and among Bonanza Creek Energy, Inc., the Administrative Agent and the Lenders under that certain Credit Agreement, dated as of December 7, 2018 (as amended or restated from time to time) (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on May 21, 2021).
10.28	Support Agreement, dated as of June 6, 2021, by and among Bonanza Creek Energy, Inc., CPPIB Crestone Peak Resources Canada Inc., and CPPIB Crestone Peak Resources America Inc. (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on June 8, 2021).
10.29	Amended and Restated Voting Agreement, dated as of June 6, 2021 and effective as of May 9, 2021, by and among Bonanza Creek Energy, Inc., Extraction Oil & Gas, Inc. and Kimmeridge Energy Management Company, LLC (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on June 8, 2021).
10.30	Director Compensation Program, dated November 1, 2021 (incorporated by reference to Exhibit 10.10 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.31	Membership Interest Purchase Agreement, dated as of January 31, 2022, by and among Civitas Resources, Inc., Bison Oil & Gas Partners II, LLC, and Bison Oil & Gas II, LLC (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on February 1, 2022).
10.32	First Amendment to Membership Interest Purchase Agreement, dated as of February 27, 2022, by and among Civitas Resources, Inc., Bison Oil & Gas Partners II, LLC, and Bison Oil & Gas II, LLC. (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on March 2, 2022).
10.33	Severance, Release and Consulting Agreement, dated January 31, 2022 (incorporated by reference to Exhibit 10.2 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on February 1, 2022).
10.34	Board Observer and Confidentiality Agreement, dated November 1, 2021, between Civitas Resources, Inc. and CPPIB Crestone Peak Resources Canada Inc. (incorporated by reference to Exhibit 10.8 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
21.1	List of subsidiaries
23.1†	Consent of Deloitte & Touche LLP
23.2†	Consent of Independent Petroleum Engineers, Ryder Scott Company, L.P.

23.3†	Consent of Independent Petroleum Engineers, Netherland, Sewell & Associates, Inc.
31.1†	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)
31.2†	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)
32.1†	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith)
32.2†	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith)
99.1†	Report of Independent Petroleum Engineers, Ryder Scott Company, L.P., for reserves as of December 31, 2021
101.INS†	XBRL Instance Document
101.SCH†	XBRL Taxonomy Extension Schema
101.CAL†	XBRL Taxonomy Extension Calculation Linkbase
101.DEF†	XBRL Taxonomy Extension Definition Linkbase
101.LAB†	XBRL Taxonomy Extension Label Linkbase
101.PRE†	XBRL Taxonomy Extension Presentation Linkbase
104	Cover Page Interactive Data File (formatted as Inline XBRL)

* Management Contract or Compensatory Plan or Arrangement
† Filed or furnished herewith

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.

		CIVITAS RESOURCES, INC.	
Date:	March 8, 2022	By:	/s/ Benjamin Dell
			Benjamin Dell, *Interim Chief Executive Officer* *(principal executive officer)*

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Benjamin Dell, Marianella Foschi, Cyrus D. Marter IV, and Sandi K. Garbiso and each of them severally, his true and lawful attorney or attorneys-in-fact and agents, with full power to act with or without the others and with full power of substitution and resubstitution, to execute in his name, place, and stead, in any and all capacities, any or all amendments to this report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents and each of them, full power and authority to do and perform in the name of on behalf of the undersigned, in any and all capacities, each and every act and thing necessary or desirable to be done in and about the premises, to all intents and purposes and as fully as they might or could do in person, hereby ratifying, approving and confirming all that said attorneys-in-fact and agents or their substitutes may lawfully do or cause to be done by virtue hereof.

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

Date:	March 8, 2022	By:	/s/ Benjamin Dell
			Benjamin Dell, *Chairman of the Board and Interim Chief Executive Officer* *(principal executive officer)*
Date:	March 8, 2022	By:	/s/ Marianella Foschi
			Marianella Foschi, *Chief Financial Officer (principal financial officer)*
Date:	March 8, 2022	By:	/s/ Sandi K. Garbiso
			Sandi K. Garbiso, *Chief Accounting Officer and Treasurer* *(principal accounting officer)*
Date:	March 8, 2022	By:	/s/ Morris R. Clark
			Morris R. Clark, *Director*
Date:	March 8, 2022	By:	/s/ Carrie M. Fox
			Carrie M. Fox, *Director*
Date:	March 8, 2022	By:	/s/ Carrie Hudak
			Carrie Hudak, *Director*
Date:	March 8, 2022	By:	/s/ Brian Steck
			Brian Steck, *Director*
Date:	March 8, 2022	By:	/s/ James Trimble
			James Trimble, *Director*
Date:	March 8, 2022	By:	/s/ Howard A. Willard, III
			Howard A. Willard, III, *Director*
Date:	March 8, 2022	By:	/s/ Jeffrey E. Wojahn
			Jeffrey E. Wojahn, *Director*

Exhibit 21.1

Subsidiaries of Civitas Resources, Inc., a Delaware corporation

SUBSIDIARIES OF CIVITAS RESOURCES, INC. (f/k/a BONANZA CREEK ENERGY, INC.):
- BONANZA CREEK ENERGY OPERATING COMPANY, LLC, a Delaware limited liability company
- HIGHPOINT RESOURCES CORPORATION, a Delaware corporation
- EXTRACTION OIL & GAS, INC., a Delaware corporation
- RAPTOR CONDOR MERGER SUB 2, LLC, a Delaware limited liability company
- BISON OIL & GAS II, LLC, a Colorado limited liability company

SUBSIDIARIES OF BONANZA CREEK ENERGY OPERATING COMPANY, LLC:
- ROCKY MOUNTAIN INFRASTRUCTURE, LLC, a Delaware limited liability company
- HOLMES EASTERN COMPANY, LLC, a Delaware limited liability company

SUBSIDIARIES OF HIGHPOINT RESOURCES CORPORATION:
- HIGHPOINT OPERATING CORPORATION, a Delaware corporation

SUBSIDIARIES OF HIGHPOINT OPERATING CORPORATION:
- FIFTH POCKET PRODUCTION, LLC, a Colorado limited liability company

SUBSIDIARIES OF EXTRACTION OIL & GAS, INC.:
- EXTRACTION FINANCE CORP., a Delaware corporation
- MOUNTAINTOP MINERALS, LLC, a Delaware limited liability company
- TABLE MOUNTAIN RESOURCES, LLC, a Delaware limited liability company
- NORTHWEST CORRIDOR HOLDINGS, LLC, a Delaware limited liability company
- XTR MIDSTREAM, LLC, a Delaware limited liability company
- 7N, LLC, a Delaware limited liability company
- 8 NORTH, LLC, a Delaware limited liability company
- AXIS EXPLORATION, LLC, a Delaware limited liability company
- XOG SERVICES, LLC, a Delaware limited liability company

SUBSIDIARIES OF RAPTOR CONDOR MERGER SUB 2, LLC:
- CRESTONE PEAK RESOURCES GP INC., a Delaware corporation
- CRESTONE PEAK RESOURCES LP, a Delaware limited partnership
- CRESTONE PEAK RESOURCES LLC, a Delaware limited liability company
- CRESTONE PEAK RESOURCES ACQUISITION COMPANY I LLC, a Delaware limited liability company
- CRESTONE PEAK RESOURCES OPERATING LLC, a Delaware limited liability company
- CRESTONE PEAK RESOURCES MIDSTREAM LLC, a Delaware limited liability company
- CRESTONE PEAK RESOURCES HOLDINGS LLC, a Delaware limited liability company
- COLLEGIATE HOLDINGS LLC, a Delaware limited liability company
- CRESTONE PEAK RESOURCES WATKINS MIDSTREAM LLC, a Delaware limited liability company
- CRESTONE PEAK RESOURCES WATKINS HOLDINGS LLC, a Delaware limited liability company

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-217545, 333-229431, 333-257295 and 333-260881 on Form S-8 of our reports dated March 8, 2022, relating to the financial statements of Civitas Resources, Inc. (formerly Bonanza Creek Energy, Inc.) and its subsidiaries (the “Company”) and the effectiveness of the Company’s internal control over financial reporting appearing in this Annual Report on Form 10-K for the year ended December 31, 2021.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 8, 2022

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580

633 SEVENTEENTH STREET, SUITE 1700 DENVER, COLORADO 80202 (303) 339-8110

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of Civitas Resources, Inc. for the year ended December 31, 2021. We further consent to the incorporation by reference thereof into Civitas Resources, Inc.'s Registration Statements on Form S-8 (Registration Nos. 333-217545, 333-229431, 333-257925 and 333-260881).

By: /s/Ryder Scott Company, L.P.
RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Denver, Colorado
March 8, 2022

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

Exhibit 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of Civitas Resources, Inc. for the year ended December 31, 2021. We further consent to the incorporation by reference thereof into Civitas Resources, Inc.'s Registration Statements on Form S-8 (Registration Nos. 333-217545, 333-229431, 333-257925 and 333-260881).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dallas, Texas
March 8, 2022

Exhibit 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER PURSUANT TO RULE 13a‑14(a)

I, Benjamin Dell, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2021 of Civitas Resources, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the periods covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

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

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 8, 2022

/s/ Benjamin Dell

Benjamin Dell
Chairman of the Board and Interim Chief Executive Officer
(principal executive officer)

Exhibit 31.2

CERTIFICATION OF THE PRINCIPAL FINANCIAL OFFICER PURSUANT TO RULE 13a-14(a)

I, Marianella Foschi, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2021 of Civitas Resources, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the periods covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

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

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 8, 2022

/s/ Marianella Foschi

Marianella Foschi
Chief Financial Officer (principal financial officer)

Exhibit 32.1

Certification of the Chief Executive Officer
Pursuant to 18 U.S.C. Section 1350,
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Civitas Resources, Inc. (the “Company”) on Form 10-K for the year ended December 31, 2021 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Benjamin Dell, Interim Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: March 8, 2022

/s/ Benjamin Dell
Benjamin Dell
Chairman of the Board and Interim Chief Executive Officer
(principal executive officer)

Exhibit 32.2

Certification of the Principle Financial Officer
Pursuant to 18 U.S.C. Section 1350,
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Civitas Resources, Inc. (the "Company") on Form 10-K for the year ended December 31, 2021 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Marianella Foschi, Chief Financial Officer, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: March 8, 2022

/s/ Marianella Foschi

Marianella Foschi
Chief Financial Officer (principal financial officer)

CIVITAS RESOURCES, Inc.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2021

/s/ Scott J. Wilson
Scott J. Wilson, P.E., MBA
Colorado License No. 36112
Senior Vice President

/s/ Edward M. Polishuk
Edward M. Polishuk
Senior Petroleum Evaluator

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

February 20, 2022

Civitas Resources, Inc.
555 17th Street, Suite 3700
Denver, Colorado 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Civitas Resources, Inc. (Civitas) as of December 31, 2021. The subject properties are located in the state of Colorado. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on February 20, 2022 and presented herein, was prepared for public disclosure by Civitas in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Civitas as of December 31, 2021.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2021 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
Civitas Resources, Inc.
As of December 31, 2021

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate – Mbbl	97,996	6,082	39,501	143,579
Plant Products – Mbbl	84,914	4,053	17,061	106,028
Gas – MMcf	713,958	34,804	139,737	888,499
Income Data ($M)				
Future Gross Revenue	$10,445,606	$549,035	$3,304,278	$14,298,919
Deductions	3,882,701	366,598	1,810,076	6,059,375
Future Net Income (FNI)	$ 6,562,905	$182,437	$1,494,202	$ 8,239,544
Discounted FNI @ 10%	$ 4,301,744	$161,561	$ 863,850	$ 5,327,155

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the area in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of Civitas. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, plant treatment costs, ad valorem taxes, development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 84 percent and gas reserves account for the remaining 16 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates, which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2021
Discount Rate Percent	Total Proved
5	$6,446,319
15	$4,567,148
20	$4,017,602
25	$3,601,122

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined under the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of wells shut in due to offset completion activity or waiting on facility connection.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Civitas's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Civitas's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Civitas owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

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 set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). 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 individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods, which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods or analogy. Approximately one hundred percent of the proved producing reserves were estimated by performance methods. These performance methods include decline curve analysis, which utilized extrapolations of historical production data available through December 2021 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Civitas and were considered sufficient for the purpose thereof.

Approximately ten percent of the proved developed non-producing reserves were estimated by historical performance prior to the wells being shut in. The remaining ninety percent of proved developed non-producing reserves were estimated by analogy. Approximately one hundred percent of the proved undeveloped reserves included herein, were estimated by analogy. The data utilized from the shut-in wells and from the analogues were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Civitas has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Civitas with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Civitas. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Civitas. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling and completing wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

Civitas furnished us with the above mentioned average prices in effect on December 31, 2021. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by Civitas. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Civitas to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Proved Realized Prices
North America				
	Oil/Condensate	WTI Cushing	$66.56/bbl	$61.60/bbl
United States	NGLs	WTI Cushing	$66.56/bbl	$30.60/bbl
	Gas	Henry Hub	$3.598/MMBTU	$2.60/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations

Costs

Operating costs for the leases and wells in this report were furnished by Civitas and are based on the operating expense reports of Civitas and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For Civitas operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-Civitas-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Civitas. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Civitas and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by Civitas were accepted without independent verification.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Civitas's plans to develop these reserves as of December 31, 2021. The implementation of Civitas's development plans as presented to us and incorporated herein is subject to the approval process adopted by Civitas's management. As the result of our inquiries during the course of preparing this report, Civitas has informed us that the development activities included herein have been subjected to and received the internal approvals required by Civitas's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Civitas. Civitas has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Civitas has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2021, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Civitas were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Civitas. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Civitas.

Civitas makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Civitas has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-8 of Civitas, of the references to our name, as well as to the references to our third party report for Civitas, which appears in the December 31, 2021 annual report on Form 10-K of Civitas. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Civitas.

We have provided Civitas with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Civitas and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Scott J. Wilson

Scott J. Wilson, P.E., MBA
Colorado License No. 36112

Senior Vice President **[SEAL]**

/s/ Edward M. Polishuk

Edward M. Polishuk
Senior Petroleum Evaluator

SJW-EMP (FWZ)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Scott James Wilson was the primary technical person responsible for the estimate of the reserves, future production, and income presented herein.

Mr. Wilson, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2000, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Wilson served in a number of engineering positions with Atlantic Richfield Company. For more information regarding Mr. Wilson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com.

Mr. Wilson earned a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines in 1983 and an MBA in Finance from the University of Colorado in 1985, graduating from both with High Honors. He is a registered Professional Engineer by exam in the States of Alaska, Colorado, Texas, and Wyoming. He is also an active member of the Society of Petroleum Engineers; serving as co-Chairman of the SPE Reserves and Economics Technology Interest Group, and Gas Technology Editor for SPE's Journal of Petroleum Technology. He is a member and past chairman of the Denver section of the Society of Petroleum Evaluation Engineers. Mr. Wilson has published several technical papers, one chapter in Marine and Petroleum Geology and two in SPEE monograph 4, which was published in 2016. He is the primary inventor on four US patents and won the 2017 Reservoir Description and Dynamics award for the SPE Rocky Mountain Region.

In addition to gaining experience and competency through prior work experience, several state Boards of Professional Engineers require a minimum number of hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Wilson fulfills as part of his registration in four states. As part of his continuing education, Mr. Wilson attends internally presented training as well as public forums relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, and Final Rule released January 14, 2009 in the Federal Register. Mr. Wilson attends additional hours of formalized external training covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on his educational background, professional training and more than 35 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Wilson has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, Civitas method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized Civitas technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and 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 gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be 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).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and 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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed Civitas equipment and infrastructure operational at the time of the reserves estimate if the Civitas is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.