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

For the transition period from _______________ to _______________

Commission file number: **001-31899**

WHITING PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**20-0098515**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1700 Lincoln Street, Suite 4700 Denver, Colorado	**80203-4547**
(Address of principal executive offices)	(Zip code)

(303) 837-1661
(Registrant's telephone number, including area code)

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

Common Stock, $0.001 par value	**WLL**	**New York Stock Exchange**
(Title of each class)	(Trading Symbol)	(Name of each exchange on which registered)

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 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	☒	Smaller reporting company	☐
Accelerated filer	☐	Emerging growth company	☐
Non-accelerated filer	☐		

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 Exchange 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 ☐

Aggregate market value of the voting common stock held by non-affiliates of the registrant at June 30, 2021: $2,126,000,000.

Number of shares of the registrant's common stock outstanding at February 17, 2022: 39,240,791 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2022 Annual Meeting of Stockholders are incorporated by reference into Part III.

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GLOSSARY OF CERTAIN DEFINITIONS

Unless the context otherwise requires, the terms "we," "us," "our" or "ours" when used in this Annual Report on Form 10-K refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries. When the context requires, we refer to these entities separately.

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

"ASC" Accounting Standards Codification.

"Bankruptcy Code" Title 11 of the United States Code.

"Bankruptcy Court" United States Bankruptcy Court for the Southern District of Texas.

"basis swap" or "differential swap" A derivative instrument that guarantees a fixed price differential to NYMEX at a specified delivery point. We receive the difference between the floating market price differential and the fixed price differential from the counterparty if the floating market differential is greater than the fixed price differential for the hedged commodity. We pay the difference between the floating market price differential and the fixed price differential to the counterparty if the fixed price differential is greater than the floating market differential for the hedged commodity.

"Bbl" One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil, NGLs and other liquid hydrocarbons.

"Bcf" One billion cubic feet, used in reference to natural gas.

"Board" The board of directors of Whiting Petroleum Corporation.

"BOE" One stock tank barrel of oil equivalent, computed on an approximate energy equivalent basis that one Bbl of crude oil equals six Mcf of natural gas and one Bbl of crude oil equals one Bbl of natural gas liquids.

"Btu" or *"British thermal unit"* The quantity of heat required to raise the temperature of one pound of water one degree Fahrenheit.

"completion" The process of preparing an oil and gas wellbore for production through the installation of permanent production equipment, as well as perforation and fracture stimulation to optimize production.

"Credit Agreement" A reserves-based credit facility with a syndicate of banks that was entered into by Whiting Petroleum Corporation, as parent guarantor, and Whiting Oil and Gas Corporation, as borrower on September 1, 2020. Refer to the Long-Term Debt footnote in Item 8. "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K for more information.

"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.

"development well" A well drilled within the proved area of an oil or natural gas 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 price, and the wellhead price received.

"dry hole" or "dry well" A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

"EOR" Enhanced oil recovery.

"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 natural gas in another reservoir.

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

"FASB" Financial Accounting Standards Board.

"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 that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or 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.

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

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

"ISDA" International Swaps and Derivatives Association, Inc.

"lease operating expense" or "LOE" The expenses of lifting oil or gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

"LIBOR" London interbank offered rate.

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

"MBbl/d" One MBbl per day.

"MBOE" One thousand BOE.

"MBOE/d" One MBOE per day.

"Mcf" One thousand cubic feet, used in reference to natural gas.

"MMBbl" One million barrels of oil, NGLs or other liquid hydrocarbons.

"MMBOE" One million BOE.

"MMBtu" One million British Thermal Units, used in reference to natural gas.

"MMcf" One million cubic feet, used in reference to natural gas.

"MMcf/d" One MMcf per day.

"net acres" or *"net wells"* The sum of the fractional working interests owned in gross acres or wells, as the case may be.

"net production" The total production attributable to our fractional working interest owned.

"NGL" Natural gas liquid.

"NYMEX" The New York Mercantile Exchange.

"PDNP" Proved developed nonproducing reserves.

"PDP" Proved developed producing reserves.

"plugging and abandonment" Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of most states legally require plugging of abandoned wells.

"pre-tax PV10%" The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with the guidelines of the SEC, net of estimated lease operating expense, transportation, gathering, compression and other expense, production taxes, future development costs and future abandonment costs, using costs as of the date of estimation without future escalation and using an average of the first-day-of-the-month price for each of the 12 months within the fiscal year, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, or federal income taxes and discounted using an annual discount rate of 10%. Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the SEC. Refer to the footnote to the Proved Reserves table in Item 1. "Business" of this Annual Report on Form 10-K for more information.

"probabilistic method" The method of estimating reserves using the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) to generate a full range of possible outcomes and their associated probabilities of occurrence.

"prospect" A property on which indications of oil or gas have been identified based on available seismic and geological information.

"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 reserves 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.

The area of the reservoir considered as proved includes all of the following:

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.

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

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.

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 before 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 "PUDs" 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 of 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.

"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 with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

"recompletion" An operation whereby a completion in one zone is abandoned in order to attempt a completion in a different zone within the existing wellbore.

"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.

"resource play" An expansive contiguous geographical area with known accumulations of crude oil or natural gas reserves that has the potential to be developed uniformly with repeatable commercial success due to advancements in horizontal drilling and completion technologies.

"royalty" The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from crude oil or natural gas produced and sold, unencumbered by expenses relating to the drilling, completing or operating of the affected well.

"royalty interest" An interest in an oil or natural gas property entitling the owner to shares of the crude oil or natural gas production free of costs of exploration, development and production operations.

"SEC" The United States Securities and Exchange Commission.

"standardized measure of discounted future net cash flows" or *"Standardized Measure"* The discounted future net cash flows relating to proved reserves based on the average price during the 12-month period before 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); current costs and statutory tax rates (to the extent applicable); and a 10% annual discount rate.

"turn-in-line" or "TIL" To turn a drilled and completed well online to begin sales.

"two-way collar" An option position where the proceeds from the sale of a call option at its inception fund the purchase of a put option at its inception.

"working interest" The interest in a crude oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and to a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all associated risks.

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

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PART I

Item 1. Business

Overview

We are an independent oil and gas company engaged in development, production and acquisition activities primarily in the Rocky Mountains region of the United States where we are focused on developing our large resource play in the Williston Basin of North Dakota and Montana. Since our inception, we have built a strong asset base through a combination of property acquisitions, development of proved reserves and exploration activities. We are currently focusing our capital programs on drilling and workover opportunities that we believe provide attractive well-level returns in order to maintain consistent production levels and generate free cash flow. In addition, we are selectively pursuing acquisitions that complement our existing core properties. During 2021, we focused on high-return projects in our asset portfolio that generated significant cash flow from operations. We continually evaluate our property portfolio and sell properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own. Refer to "Acquisitions and Divestitures" below for a summary of certain recent asset purchase and sale activity.

As of December 31, 2021, our estimated proved reserves totaled 326.0 MMBOE and our 2021 average daily production was 91.9 MBOE/d.

The following table summarizes, by core area, our estimated proved reserves as of December 31, 2021 with the corresponding pre-tax PV10% values, our fourth quarter 2021 average daily production rates, and our total standardized measure of discounted future net cash flows as of December 31, 2021:

	Proved Reserves [1]						
Core Area	**Oil (MMBbl)**	**NGLs (MMBbl)**	**Natural Gas (Bcf)**	**Total (MMBOE)**	**% Oil**	**Pre-Tax PV10% Value [2] (in millions)**	**4th Quarter 2021 Average Daily Production (MBOE/d)**
North Dakota & Montana	183.6	66.3	422.5	320.3	57%	$ 4,342	91.6
Other [3]	5.0	0.1	3.5	5.7	88%	39	1.2
Total	**188.6**	**66.4**	**426.0**	**326.0**	**58%**	**$ 4,381**	**92.8**
Discounted future income tax expense						**(702)**	
Standardized measure of discounted future net cash flows						**$ 3,679**	

(1) Oil and gas reserve quantities and related discounted future net cash flows have been derived from a WTI oil price of $66.56 per Bbl and a Henry Hub gas price of $3.60 per MMBtu, which were calculated using an average of the first-day-of-the-month price for each month within the 12 months ended December 31, 2021 as required by SEC and FASB guidelines.

(2) Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows (the "Standardized Measure"), which is the most directly comparable GAAP financial measure. Pre-tax PV10% is computed on the same basis as the Standardized Measure but without deducting future income taxes. We believe pre-tax PV10% is a useful measure for investors when evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our pre-tax PV10% as a basis for comparison of the relative size and value of our proved reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and gas properties and acquisitions. However, pre-tax PV10% is not a substitute for the Standardized Measure. Our pre-tax PV10% and Standardized Measure do not purport to present the fair value of our proved oil, NGL and natural gas reserves.

(3) Primarily includes non-core oil and gas properties located in Arkansas, Colorado, Mississippi, New Mexico, Texas and Wyoming.

During 2021, we incurred $247 million in exploration and development ("E&D") expenditures for the drilling of 41 gross (25.5 net) wells and the completion of 57 gross (34.4 net) operated and nonoperated wells.

Our current 2022 E&D budget is a range of $360 million to $400 million, which we expect to fund with net cash provided by operating activities and cash on hand. Our level of E&D expenditures is largely discretionary, although a portion of our E&D expenditures are for non-operated properties where we have limited control over the timing and amount of such expenditures, and the amount of funds we devote to any particular activity may increase or decrease significantly depending on commodity prices, cash flows, available opportunities and development results, among other factors. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we would generate more or less free cash flow than we currently anticipate and could adjust our E&D budget, our cash on hand or our borrowings outstanding under our credit facility.

On April 1, 2020, we and certain of our subsidiaries (collectively, the "Debtors") commenced voluntary cases (the "Chapter 11 Cases") under chapter 11 of the Bankruptcy Code. On June 30, 2020, the Debtors filed the Joint Chapter 11 Plan of Reorganization of Whiting Petroleum Corporation and its Debtor affiliates (as amended, modified, and supplemented, the "Plan"). On August 14, 2020, the Bankruptcy Court confirmed the Plan and on September 1, 2020 (the "Emergence Date"), the Debtors satisfied all conditions required for Plan effectiveness and emerged from the Chapter 11 Cases. Upon emergence, we adopted fresh start accounting in accordance with FASB ASC Topic 852 – *Reorganizations*, which specifies the accounting and financial reporting requirements for entities reorganizing through chapter 11 bankruptcy proceedings. The application of fresh start accounting resulted in a new basis of accounting and us becoming a new entity for financial reporting purposes. As a result of the implementation of the Plan and the application of fresh start accounting, the consolidated financial statements after the Emergence Date are not comparable to the consolidated financial statements before that date and the historical financial statements on or before the Emergence Date are not a reliable indicator of our financial condition and results of operations for any period after our adoption of fresh start accounting. Refer to the "Fresh Start Accounting" footnote in the consolidated financial statements in Item 8 of this Annual Report on Form 10-K for more information. References to "Successor" refer to the Whiting entity and its financial position and results of operations after the Emergence Date. References to "Predecessor" refer to the Whiting entity and its financial position and results of operations on or before the Emergence Date.

Acquisitions and Divestitures

Recent Acquisitions and Divestitures. In September 2021, we completed the acquisition of interests in oil and gas properties located in Mountrail County, North Dakota for an aggregate purchase price of $271 million (before closing adjustments).

In December 2021, we completed the acquisition of additional interests in oil and gas properties located in Mountrail County, North Dakota for an aggregate purchase price of $32 million (before closing adjustments).

Subsequent to December 31, 2021, we entered into a purchase and sale agreement to acquire additional interests in oil and gas properties located in Mountrail County, North Dakota for an aggregate purchase price of $240 million (before closing adjustments). We expect this transaction to close in March 2022. We intend to finance this acquisition with cash on hand and borrowings under our Credit Agreement.

On a combined basis, our recent Williston Basin acquisitions included interests in 76 new gross producing oil and gas wells and increased interests in 527 existing gross producing wells. Overall, the acquisitions effectively added 136.2 net producing wells and included approximately 23,300 net undeveloped acres.

In September 2021, we completed the divestiture of all of our interests in producing assets and undeveloped acreage, including the associated midstream assets, of our Redtail field located in the Denver-Julesburg Basin of Weld County, Colorado for aggregate sales proceeds of $171 million (before closing adjustments). The production from the divested properties (which was approximately 51% oil) represented approximately 8% of our average total production as of the divestiture date.

2020 Acquisitions and Divestitures. In January 2020, we completed the divestiture of our interests in 30 non-operated, producing oil and gas wells and related undeveloped acreage located in McKenzie County, North Dakota for aggregate sales proceeds of $25 million (before closing adjustments). The divested properties consisted of less than 1% of our estimated proved reserves as of December 31, 2019 and 1% of our average daily production for the year ended December 31, 2019.

There were no significant acquisitions during the year ended December 31, 2020.

2019 Acquisitions and Divestitures. In July 2019, we completed the divestiture of our interests in 137 non-operated, producing oil and gas wells located in McKenzie, Mountrail and Williams counties of North Dakota for aggregate sales proceeds of $27 million (before closing adjustments).

In August 2019, we completed the divestiture of our interests in 58 non-operated, producing oil and gas wells located in Richland County, Montana and Mountrail and Williams counties of North Dakota for aggregate sales proceeds of $26 million (before closing adjustments).

On a combined basis, the divested properties consisted of less than 1% of our estimated proved reserves as of December 31, 2018 and our April 2019 average daily production.

There were no significant acquisitions during the year ended December 31, 2019.

Business Strategy

Our goal is to generate meaningful growth in shareholder value through the development, production and acquisition of oil and gas projects with attractive rates of return on invested capital. Our assets, dedicated professionals, commitment to environmental stewardship and value-focused business execution position Whiting for success. Specifically, we have focused, and plan to continue to focus, on the following:

Efficiently Developing and Producing our Existing Properties. The development of our large resource play at our Williston Basin project in North Dakota and Montana continues to be our central objective. We have assembled approximately 731,100 gross (479,700 net) developed and undeveloped acres in this area. After suspending all drilling and completion activity in 2020 in response to depressed crude oil prices, in February 2021 we commenced drilling with one rig in the Williston Basin and added a second rig at the end of September 2021. We had one active completion crew for three quarters of 2021, and we brought online 56 gross (36.8 net) operated Bakken and Three Forks wells in the Williston Basin during the year. Under our current 2022 capital program, we expect to execute a two-rig drilling program for the majority of the year along with a slight increase in completion activity. We plan to TIL approximately 68 gross (44.4 net) wells in this area during the year.

Disciplined Financial Approach. Our goal is to remain financially strong, yet flexible, through the prudent management of our balance sheet and active management of our exposure to commodity price volatility. We have historically funded our acquisition and development activity through a combination of internally generated cash flows, equity and debt issuances, bank borrowings and certain oil and gas property divestitures, as appropriate, to maintain our financial position. During 2021, we were focused on high-return projects in our asset portfolio that generated significant cash flow from operations. We are currently focusing our capital programs on drilling and workover opportunities that we believe provide the greatest well-level returns in order to maintain consistent production levels and generate free cash flow, while selectively pursuing acquisitions that complement our existing core properties. From time to time, we monetize non-core properties and use the net proceeds from these asset sales to repay debt under our Credit Agreement or fund our E&D expenditures. For example, in each of the last three years we sold certain oil and gas properties that could no longer compete for capital or that otherwise no longer matched the profile of properties we desire to own. In addition, to support cash flow generation on our existing properties and help ensure expected cash flows from newly acquired properties, we periodically enter into derivative contracts. Typically, we use two-way collars and swaps to provide an attractive base commodity price level.

Commitment to Safety and Social Responsibility. We are committed to developing the energy resources the world needs in a safe and responsible way that allows us to protect our employees, our contractors, our vendors, the public and the environment while also meeting or exceeding regulatory requirements. We continually evolve our practices to better protect wildlife habitats and communities, to reduce freshwater use in our development process, to identify and reduce methane emissions from our operations, to encourage waste reduction programs and to promote worker safety. Additionally, we are committed to transparency in reporting our environmental, social and governance performance and to monitoring such performance through various measures, some of which are tied to our short-term incentive program for all employees. Refer to our Sustainability Report published on our website for sustainability performance highlights and additional information. Information contained in our Sustainability Report is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

Growing Through Accretive Acquisitions. Since 2014, we have completed 7 separate significant acquisitions of producing and undeveloped properties for total estimated proved reserves of 238.7 MMBOE, as of the effective dates of the acquisitions. Our experienced team of management, land, engineering and geoscience professionals has executed an acquisition program designed to increase reserves and complement our existing properties, including closing purchases and effectively managing the properties we acquire. We intend to selectively pursue the acquisition of properties that are complementary to our core operating areas, as well as explore opportunities in other basins where we can apply our existing knowledge and expertise to build production and add proved reserves.

Return of Capital. As a result of our strong operating base and our disciplined financial approach, we reduced the borrowings under our Credit Agreement to zero as of December 31, 2021. We expect that our business strategy will continue to provide sizable cash flow generation which will enable us to return capital to our shareholders and continue to pursue acquisitions that add to our inventory, while maintaining a strong balance sheet. As a first step in delivering on this commitment, in February 2022 we announced an initial regular dividend payment which will begin in the first quarter of 2022. Our Board and management are committed to returning capital in line with our industry peers and we will continue to evaluate all forms of capital returns, including buying back outstanding shares and paying variable dividends.

Competitive Strengths

We believe that our key competitive strengths lie in our focused asset portfolio, our experienced management and technical teams, our commitment to the effective application of new technologies and our commitment to cost management.

Focused, Long-Lived Asset Base. As of December 31, 2021, we had interests in 4,720 gross (1,917 net) productive wells on approximately 844,700 gross (539,900 net) developed acres across our geographical areas. We believe the concentration of our operated assets presents us with multiple opportunities to successfully execute our business strategy by enabling us to leverage our technical expertise and take advantage of operational efficiencies.

Experienced Management and Technical Teams. Our management team averages 26 years of experience in the oil and gas industry. Our personnel have extensive experience in our core geographical areas, all operational disciplines and the evaluation, acquisition and operational assimilation of oil and gas properties.

Commitment to Technology. In each of our core operating areas, we have accumulated extensive engineering, operational, geologic and geophysical technical knowledge. Our technical team has access to an abundance of digital well log, seismic, completion, production and other subsurface information, which is analyzed in order to accurately and efficiently characterize the anticipated performance of our oil and gas reservoirs. We leverage many technologies in support of data gathering, information analysis and production optimization. Artificial intelligence and machine learning solutions support both field and corporate business processes. Data management and reporting practices improve the availability, accuracy and analysis of our information in a cycle of continuous improvement. Emerging technologies are evaluated on a regular basis, ensuring we are implementing the best technologies for our business needs.

We continue to advance the development of our completion techniques to match the varying reservoir properties across the Williston Basin while utilizing the latest completion technologies available. Each new well provides us with valuable data that is evaluated and used in conjunction with publicly available third-party data to adjust the overall completion design for each of our prospect areas and unlock maximum value from our assets. Our 2022 program will continue to focus on reducing time-on-location through efficiency gains in our drilling practices and completion techniques.

Commitment to Cost Management. We are committed to continued cost management strategies to remain a lower-cost operator. During 2020, in response to the sharp decline in commodity prices, as well as our chapter 11 reorganization, we significantly reduced our operating and overhead costs. During 2021, we continued to create lease operating expense efficiencies across the majority of our properties while maintaining our substantial production base. These cost efficiencies and production maintenance efforts resulted in reductions in saltwater disposal costs by 25%, utility costs by 10% and lost oil volumes to downtime by 20% from 2020 to 2021.

We expect that our ongoing cost management efforts will result in sustainable operations and long-term value to our shareholders.

Proved Reserves

Our estimated proved reserves as of December 31, 2021 are summarized by core area in the table below. Refer to "Reserves" in Item 2 of this Annual Report on Form 10-K for information relating to the uncertainties surrounding these reserve categories.

	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% of Total Proved	Estimated Future Capital Expenditures [1] (in millions)
North Dakota & Montana						
PDP	138.5	53.5	338.6	248.5	78%	
PDNP	4.8	1.4	9.8	7.8	2%	
PUD	40.3	11.4	74.1	64.0	20%	
Total proved	**183.6**	**66.3**	**422.5**	**320.3**	**100%**	**$ 572.2**
Other [2]						
PDP	4.6	0.1	2.9	5.2	91%	
PDNP	0.4	-	0.6	0.5	9%	
Total proved	**5.0**	**0.1**	**3.5**	**5.7**	**100%**	**$ 8.5**
Total Company						
PDP	143.1	53.6	341.5	253.7	78%	
PDNP	5.2	1.4	10.4	8.3	2%	
PUD	40.3	11.4	74.1	64.0	20%	
Total proved	**188.6**	**66.4**	**426.0**	**326.0**	**100%**	**$ 580.7**

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(1) Estimated future capital expenditures incorporate numerous assumptions and are subject to many uncertainties, including oil and natural gas prices, costs of oil field goods and services, drilling results, well abandonment costs and several other factors.

(2) Primarily includes non-core oil and gas properties located in Arkansas, Colorado, Mississippi, New Mexico, Texas and Wyoming.

Marketing

We principally sell our oil and gas production to end users, marketers and other purchasers that have access to nearby pipeline or rail takeaway. In areas where there is no practical access to gathering pipelines, oil is trucked or transported to terminals, market hubs, refineries or storage facilities. We believe that the loss of any individual purchaser would not have a long-term material adverse impact on our financial position or results of operations, as alternative customers and markets for the sale of our products are readily available in the areas in which we operate.

Title to Properties

Our properties are subject to customary royalty interests, liens securing indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. Our Credit Agreement is also collateralized by a first lien on substantially all of our assets. We do not believe that any of these burdens materially interfere with the use of our properties or the operation of our business.

We believe that we have satisfactory rights or title to all of our producing properties. As is customary in the oil and gas industry, limited investigation of title is made at the time of acquisition of undeveloped properties. In most cases, we investigate title and obtain title opinions from counsel only when we acquire producing properties or before commencement of drilling operations.

Competition

There is a high degree of competition in the oil and gas industry for acquiring properties, obtaining investment capital, securing oil field goods and services, marketing oil and natural gas products and attracting and retaining qualified personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects, better sustain production in periods of low commodity prices and evaluate, bid for and purchase a greater number of properties and prospects than our resources permit. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation or regulation enacted by state, local and U.S. government bodies and their associated agencies, especially with regard to environmental protection and climate-related policies. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or the resultant effects on our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and our larger competitors may be able to better absorb the burden of such legislation and regulation, which would also adversely affect our competitive position. Refer to “Government Regulation” below as well as Item 1A within this Annual Report on Form 10-K for more information on and the potential associated risks resulting from existing and future legislation and regulation of our industry. Additionally, the unavailability or high cost of drilling rigs, completion crews or other equipment and services could delay or adversely affect our development and exploration operations. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to obtain necessary capital as well as evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

In addition, the oil and gas industry as a whole competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers. The price and availability of alternative energy sources, such as wind, solar, nuclear and electric power, as well as the emerging impact of climate change activism, fuel conservation measures and governmental requirements for renewable energy sources, could adversely affect our revenues.

Human Capital

We believe that in order to execute our strategy in the highly competitive oil and gas industry we need to attract, develop and retain a highly effective and diverse employee workforce. Our ability to do so depends on a number of factors, including an available qualified talent pool, compensation plans, benefits programs, talent development efforts, career opportunity generation and our work environment. As of January 31, 2022, we had approximately 356 full-time employees, 197 of which were field employees, primarily located in North Dakota and Montana, and 159 of which were corporate employees, primarily located in Colorado. None of our employees are represented by any labor unions. We also engage independent contractors and consultants to support our work in specific areas.

Safety. "Safety Always" is one of our core, foundational values. We strive to create a culture of safety that promotes transparency and accountability by providing the tools and resources that empower employees and contractors to identify and report potential hazards, assess risks inherent to our industry and stop work when necessary. Through health and safety training, we prepare our employees and contractors to use industry best practices and standards to mitigate risk in a manner that protects themselves, their co-workers, the public and property. We have developed a comprehensive safety management system that includes recurring risk assessment, hazard recognition and mitigation and emergency response preparedness training, protective measures including adequate personal protective equipment, life-saving rules, onboarding processes, contractor safety management, partner surveys, comprehensive audits, quarterly safety summits, executive-level reviews of incidents and ad-hoc safety stand-downs. In 2021, Whiting established corporate goals specifically related to employee and contractor safety. All employee and executive short-term incentive compensation is impacted by our performance relative to these safety goals and other performance metrics deemed material by the Board. We monitor employee and contractor safety performance based on several metrics, which are communicated to employees through a dashboard that is updated continuously. These metrics are also communicated regularly to senior management and key operational employees to monitor progress, provide opportunities for training and reinforce the importance of safety. Two key metrics that we monitor are our Combined Total Recordable Incident Rate and our Days Away, Restricted and/or Transferred Rate. Whiting seeks to only partner with contractors and vendors who share our commitment to safety.

Diversity, Equity and Inclusion. We recognize the advantages of a company culture that embraces diversity, constructive debate and differing viewpoints, continuous learning, servant leadership and an engaged workforce. We believe that a workforce diverse in background and experience will create such a culture. We recruit, hire, promote and perform personnel actions without regard to race, color, religion, sex, national origin, age, disability, genetic information or any other applicable status under federal, state or local law. Whiting's leadership is mindful of ways to increase the diversity of our workforce and our Board. In order to continually grow our diversity of background and experience, we actively make appropriate efforts to increase the percentage of our workforce that is female or minority while also maintaining the high qualification standards required of Whiting employees. Additionally, we have achieved gender parity among our independent directors.

Ethics. Whiting is committed to demonstrating adherence to our corporate core values, the first of which is "Highest Integrity." We expect all of our employees, officers and directors to adhere to our Code of Business Conduct and Ethics. Whiting has an Ethics Hotline for the purpose of allowing all employees an avenue for confidential, anonymous submission of concerns.

Competitive Compensation and Benefits. The objective of our compensation program is to maintain a strong pay-for-performance culture in order to attract, retain and motivate employees. Our program includes competitive market-based salaries, short-term incentives that tie to corporate and individual performance, long-term incentives, market-competitive health benefits and other appropriate benefits including workplace flexibility.

Training, Development and Career Opportunities. We are committed to the personal and professional development of our employees, with the belief that a greater level of knowledge, skill and ability is of personal benefit to the employee and fosters a more creative, innovative, efficient and therefore competitive company. We empower our employees to develop the skills they need to perform their current jobs while developing acumen for future opportunities. We want our talent pool to envision a successful and fulfilling career progression within our company.

Refer to our Sustainability Report published on our website for performance highlights regarding various human capital measures and additional information. Information contained in our Sustainability Report is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

Government Regulation

Regulation of Production

The production of oil and 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 permits for drilling operations, drilling bonds and periodic report submittals during operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum allowable rates of production from oil and gas wells, the regulation of well spacing and the plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and gas that we can produce from our wells and to limit the number of wells or the locations that we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production or sale of oil, NGLs and natural gas within its jurisdiction.

Currently, none of our production volumes are produced from offshore leases, however, some of our prior offshore operations were conducted on federal leases that are administered by the Bureau of Ocean Energy Management (the "BOEM"). Among other things, BOEM regulations, along with regulations of the Bureau of Safety and Environmental Enforcement ("BSEE"), govern the plugging and

abandonment of wells and the removal of production facilities from these leases. We are therefore required to comply with the regulations and orders issued by the BOEM and BSEE under the Outer Continental Shelf Lands Act.

The Bureau of Land Management (the "BLM") and Office of Natural Resources Revenue (the "ONRR") establish the basis for onshore royalty payments due under federal oil and gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and gas leases. The basis for royalty payments established by the BLM, the ONRR and the state regulatory authorities is generally applicable to all federal and state oil and gas lessees. Accordingly, we believe that the impact of royalty regulation on our operations should generally be the same as the impact on our competitors.

Regulation of Sale and Transportation of Oil

Our crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission (the "FERC") regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for crude oil transportation rates that allowed for an increase or decrease in the cost of transporting oil to the purchaser. The FERC's regulations include a methodology for oil pipelines to change their rates through the use of an index system that establishes ceiling levels for such rates. The most recent mandatory five-year review period resulted in a 2020 order from the FERC for the index to be based on the Producer Price Index for Finished Goods (the "PPI-FG") plus 0.78 percent (PPI-FG+0.78%) for the five-year period from July 1, 2021 to June 30, 2026. This represents a decrease from the PPI-FG plus 1.23% adjustment from the prior five-year period. The FERC uses a calculation based on a data source that reflects actual cost-of-service data. The regulations provide that each year the Commission will publish the oil pipeline index after the PPI-FG becomes available. 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 of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. In addition, the FERC has emergency authority under the Interstate Commerce Act to intervene and direct priority use of oil pipeline transportation capacity. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Transportation and safety of oil and hazardous liquid is subject to regulation by the Department of Transportation (the "DOT") under the Pipeline Integrity, Protection, Enforcement and Safety Act of 2006 and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2012. The Pipeline and Hazardous Material Safety Administration ("PHMSA"), an agency within the DOT, enforces regulations on all interstate liquids transportation and some intrastate liquids transportation. The effect of regulatory changes under the DOT and their effect on interstate and intrastate oil and hazardous liquid transportation will not affect our operations in any way that is of material difference from those of our competitors.

A portion of our crude oil production may be shipped to market centers using rail transportation facilities owned and operated by third parties. The DOT, generally, and PHMSA, more specifically, establish safety regulations relating to crude-by-rail transportation. In addition, third-party rail operators are subject to the regulatory jurisdiction of the Surface Transportation Board of the DOT, the Federal Railroad Administration (the "FRA") of the DOT, the Occupational Safety and Health Administration and other federal regulatory agencies.

In response to rail accidents, the U.S. Congress passed the Rail Safety and Improvement Act of 2008, which implemented regulations governing different areas related to railroad safety. In response to train derailments occurring in the United States and Canada, U.S. regulators have taken a number of additional actions to address the safety risks of transporting crude oil by rail.

In February 2014, the DOT issued an emergency order requiring all persons to ensure crude oil is properly tested and classed prior to offering such product into transportation, and to assure all shipments by rail of crude oil be handled as a Packing Group I or II hazardous material. Also in February 2014, the Association of American Railroads entered into a voluntary agreement with the DOT to implement certain restrictions around the movement of crude oil by rail. In May 2014 (and extended indefinitely in May 2015), the DOT issued an Emergency Restriction/Prohibition Order requiring each railroad carrier operating trains transporting 1,000,000 gallons or more of Bakken crude oil to provide notice to state officials regarding the expected movement of the trains through the counties in each state. The PHMSA and FRA have also issued safety advisories and alerts regarding oil transportation and have issued a report focused on the increased volatility and flammability of Bakken crude oil as compared with other crudes in the U.S. In May 2015, PHMSA issued

rules applicable to "high-hazard flammable trains," defined as a continuous block of 20 or more tank cars loaded with a flammable liquid or 35 or more tank cars loaded with a flammable liquid dispersed throughout a train. Among other requirements, the rules require enhanced standards for newly constructed tank cars and retrofitting of existing tank cars, restricted operating speeds, a documented testing and sampling program, and routine assessments that evaluate certain safety and security factors. In June 2016, the Protecting our Infrastructure of Pipelines and Enhancing Safety ("PIPES") Act became law. The PIPES Act strengthens PHMSA's safety authority, including by expanding its ability to issue emergency orders, which was adopted by rule in October 2016 and further enhanced by rule in October 2019. PHMSA continues to review further potential new safety regulations under the PIPES Act.

We do not currently own or operate rail transportation facilities or rail cars. However, the adoption of any regulations that impact the testing or rail transportation of crude oil could increase our costs of doing business and limit our ability to transport and sell our crude oil at favorable prices at market centers throughout the U.S., the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows. The effect of any such regulatory changes will not affect our operations in any way that is of material difference from those of our competitors.

Regulation of Transportation, Storage, Sale and Gathering of Natural Gas

The FERC regulates the transportation and, to a lesser extent, the sale of natural gas for resale in interstate commerce pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 and regulations issued under those Acts. In 1989, however, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas, effective January 1, 1993. While sales by producers of natural gas can currently be made at unregulated market prices, in the future Congress could reenact price controls or enact other legislation with detrimental impact on many aspects of our business.

Our natural gas sales are affected by the availability, terms and cost of transportation. The price and terms of access to pipeline transportation and underground storage are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and the FERC that affect the economics of natural gas production, transportation and sales. In addition, the FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry that remain subject to the FERC's jurisdiction, most notably interstate natural gas transmission companies and certain underground storage facilities. These initiatives may also affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. Owners of natural gas pipelines are responsible for administering FERC-approved tariffs which govern the availability, terms and costs of transportation on specific pipelines. Owners of natural gas pipelines may propose changes to these tariffs. Such proposals are subject to comment by interested parties and must be approved by FERC before taking effect. For example, in May 2020 Northern Border Pipeline Company proposed changes to the gas quality standards in its tariff which would have negatively impacted our interests and those of many other pipeline customers. FERC ultimately rejected that proposal in November 2020, but similar proposals could be presented to FERC in the future.

We cannot accurately predict whether the FERC's actions will achieve the goal of increasing competition in the markets in which our natural gas is sold. Regulations implemented by the FERC could result in an increase in the cost of transportation service on certain petroleum product pipelines. In addition, the natural gas industry has historically been heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Transportation and safety of natural gas is subject to regulation by the DOT under the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2012. In addition, intrastate natural gas transportation is subject to enforcement by state regulatory agencies and PHMSA enforces regulations on interstate natural gas transportation. State regulatory agencies can also create their own transportation and safety regulations as long as they meet PHMSA's minimum requirements. 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 any of the states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Likewise, the effect of regulatory changes by the DOT and their effect on interstate natural gas transportation will not affect our operations in any way that is of material difference from those of our competitors.

The failure to comply with these rules and regulations can result in substantial penalties. We use the latest tools and technologies to remain compliant with current pipeline safety regulations.

In October 2015, a failure at an underground natural gas storage facility in Southern California prompted PHMSA to issue an advisory bulletin reminding owners and operators of underground storage facilities to review operations, identify the potential for facility leaks and failures and to review and update emergency plans. The State of California proclaimed the underground natural gas storage facility

an emergency situation in January 2016. A federal task force was also convened to make recommendations to help avoid such failures. An interim final rule of PHMSA became effective in January 2017 which adopted certain specific industry recommended practices into Part 192 of the Federal Pipeline Safety Regulations. PHMSA later reopened the post-promulgation comment period through November 2017 in response to petitions for reconsideration and has stated it would consider such comments further when it adopts a final rule. Under the interim final rule, if an operator fails to take any measures recommended it would need to justify in its written procedures why the measure is impracticable and unnecessary. PHMSA regulations had previously covered much of the surface piping up to the wellhead at underground natural gas storage facilities served by pipelines and did not extend in part to the "downhole" portion of these facilities. The adopted requirements cover design, construction, material, testing, commissioning, reservoir monitoring and recordkeeping for existing and newly constructed underground natural gas storage facilities as well as procedures and practices for newly constructed and existing underground natural gas storage facilities, such as operations, maintenance, threat identification, monitoring, assessment, site security, emergency response and preparedness, training, recordkeeping and reporting. These regulations and any further increased attention to and requirements for underground storage safety and infrastructure by state and federal regulators that may result from this incident will not affect us in a way that materially differs from the way it affects other natural gas producers.

Environmental Regulations

General. Our oil and gas development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge or release of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency (the "EPA"), issue regulations to implement and enforce such laws, which often require costly compliance measures that carry substantial penalties for noncompliance. These laws and regulations may require the acquisition of a permit before drilling or facility construction commences; restrict the types, quantities and concentrations of various materials that can be released into the environment; limit or prohibit project siting, construction or drilling activities on certain lands; require remedial and closure activities to prevent pollution from former operations; and impose substantial liabilities for unauthorized pollution. The EPA and analogous state agencies may delay or refuse the issuance of required permits or otherwise include onerous or limiting permit conditions that may have a significant adverse impact on our ability to conduct operations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly material handling, storage, transport, disposal or cleanup requirements could materially and adversely affect our operations and financial position, as well as those of the oil and gas industry in general. While we believe that we are in compliance, in all material respects, with current applicable environmental laws and regulations, future environmental enforcement remains a material risk due to the potential magnitude of exposure in the event of noncompliance. We have incurred in the past, and expect to incur in the future, capital expenditures and operating costs related to environmental compliance. Such expenditures are included within our overall capital and operating budgets and are not separately itemized.

The environmental laws and regulations which have the most significant impact on the oil and gas exploration and production industry are as follows:

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA" or "Superfund"), and comparable state laws impose strict joint and several liability for sites contaminated by certain hazardous substances on classes of potentially responsible persons. These persons include the owner or operator of the site where a release occurred and anyone who disposed of or arranged for the disposal of the hazardous substance released at the site. Under CERCLA, such persons may be subject to 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. In the course of our ordinary operations, we may use, generate or handle material that may be regulated as "hazardous substances." Consequently, we may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites where these materials have been disposed or released.

We currently own or lease, and in the past have owned or leased, properties that for many years have been used for the exploration and production of oil and gas. Although we have used operating and disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on, under or from the properties owned or leased by us or on, under or from other locations where such substances have been taken for recycling or disposal. In addition, many of these owned and leased properties have been previously owned or operated by third parties whose treatment and disposal of hazardous substances, wastes or hydrocarbons were not under our control and not known to us. Similarly, the disposal facilities where discarded materials are sent are also often operated by third parties whose waste treatment and disposal practices are similarly not under our control. While we only use what we consider to be reputable disposal facilities, we might not know of a potential problem if the problem itself is not discovered until years later. Current and formerly owned or operated properties, adjacent affected properties, offsite disposal facilities and substances disposed or released on them may be subject to CERCLA and analogous state laws. Under these laws, we could be required:

- to investigate the source and extent of impacts from released hazardous substances;

- to remove or remediate previously disposed materials, including materials disposed or released by prior owners or operators or other third parties;
- to clean up and remediate contaminated property, including both soils and contaminated groundwater;
- to perform remedial operations to prevent future contamination, including the plugging and abandonment of wells drilled and left inactive by prior owners and operators; or
- to pay some or all of the costs of any such action.

At this time, we do not believe that we are a potentially responsible party with respect to any Superfund site and we have not been notified of any claim, liability or damages under CERCLA or any state analog.

Oil Pollution Act. The Oil Pollution Act of 1990 ("OPA") and regulations issued under OPA impose strict, joint and several liability on "responsible parties" for removal costs and damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility and the lessee, permittee or holder of a right of use and easement of the area in which an offshore facility is located. OPA establishes a liability limit for onshore facilities of $350 million per spill, while the liability limit for offshore facilities is the payment of all removal costs plus $75 million per spill damages. These limits do not apply if the spill is caused by a responsible party's gross negligence or willful misconduct; the spill resulted from a responsible party's violation of a federal safety, construction or operating regulation; a responsible party fails to report a spill or to cooperate fully in a cleanup; or a responsible party fails to comply with an order issued under the authority of the Intervention on the High Seas Act. OPA requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35 million to cover liabilities related to an oil spill for which such responsible party is statutorily responsible. The President of the United States may increase the amount of financial responsibility required under OPA by up to $150 million, depending on the risk represented by the quantity or quality of oil that is handled by the facility. Any failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to administrative penalties. We believe we are in compliance with all applicable OPA financial responsibility obligations, and we are not aware of any action or event that would subject us to liability under OPA.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. Additionally, various federal, state and local agencies have jurisdiction over transportation, storage and disposal of hazardous waste and seek to regulate movement of hazardous waste in ways not preempted by federal law. We generate solid and hazardous wastes that are subject to RCRA and comparable state laws. Drilling fluid, produced water and many other wastes associated with the exploration, development and production of crude oil or natural gas are currently exempt from RCRA's hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be regulated as hazardous waste in the future, or that the EPA could implement broader RCRA reforms at a later date. Any such change in the current RCRA exemption and comparable state laws could result in an increase in the costs to manage and dispose of wastes. Additionally, these exploration and production wastes will continue to be regulated by state agencies as solid waste and non-exempt waste streams generated by us will continue to be subject to existing onerous hazardous waste regulations. Although we do not believe the current costs of managing our wastes (as they are presently classified) to be significant, any repeal or modification of the oil and gas exploration and production exemption by administrative, legislative or judicial process, or modification of similar exemptions in analogous state statutes would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses.

Clean Water Act. The Federal Water Pollution Control Act, or the Clean Water Act, as amended (the "CWA"), and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into state waters or other waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

Where required, costs may be associated with the treatment of wastewater and/or the development and implementation of storm water pollution prevention plans. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of CWA and analogous state laws and regulations.

In addition, the CWA requires permits for discharges of dredged or filled materials into waters of the United States. These permits ("404 Permits") are under the joint jurisdiction of the EPA and the Army Corps of Engineers. 404 Permits may be required where

development or construction activities have the potential to impact wetland areas that are considered waters of the United States. In 2020, the EPA revised the definition of waters of the United States to narrow its scope from the 2015 definition that had been promulgated under the Obama administration. In large part, this rulemaking codified that "waters of the United States" include only those water bodies (including wetlands) that have a "significant nexus" to navigable waters of the United States. The rule, however, was vacated by two separate federal district courts in late 2021. On December 7, 2021, the EPA and the Army Corps of Engineers published in the Federal Register a proposed rule that would largely reinstate the previous 1986 "waters of the United States" 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"). Publication of the 2021 Proposed Rule in the Federal Register triggered a 60-day public comment period, sometime after which the rule is expected to be finalized by the agencies. Although the outcome of the 2021 Proposed Rule and any additional amendments to the regulations is unknown, the regulations under the Biden administration are undoubtedly more stringent in terms of scope. Any expansion of the scope of the CWA could increase costs associated with permitting and regulatory compliance. However, it is expected that any such change would not disparately affect us and our competitors.

Also, the U.S. Supreme Court in a 2020 case further expanded the reach of the CWA from what had been previously understood. In this case, the U.S. Supreme Court held that a CWA permit may be required when the addition of pollutants into the waters of the United States is the functional equivalent of a direct discharge into those waters. This interpretation could increase costs associated with CWA permitting or subject past activities to liability under the CWA.

Air Emissions. The Federal Clean Air Act, as amended (the "CAA"), and comparable state laws regulate emissions of various air pollutants from various industrial sources through air emissions permitting programs and also impose other monitoring and reporting requirements. New Source Performance Standards were promulgated for the oil and gas industry in 2012. These standards set limits for sulfur dioxide and volatile organic compound emissions and required application of reduced emission completion techniques by the industry. We may be required to incur certain capital or operating expenditures in the future for air pollution control equipment in connection with obtaining and maintaining pre-construction and operating permits and approvals for air emissions. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations.

In June 2016, the EPA issued a final rule regulating methane emissions from oil and natural gas operations (the "Subpart OOOOa Rule"). This rule applies to emissions from new, reconstructed and modified processes and equipment and also requires owners and operators to find and repair leaks to address fugitive emissions. In August 2020, the EPA enacted an amendment to the Subpart OOOOa Rule, which removed all methane-specific requirements from production and processing segments and removed volatile organic compounds and methane emission standards from transmission and storage facilities. On June 30, 2021, however, President Biden signed into law a joint Congressional resolution disapproving and invalidating much of the 2020 rule amendments under the prior administration, including the 2020 rule's rescission of the methane requirements. On November 15, 2021, the EPA published in the Federal Register a proposed rule that would update and expand existing requirements for the oil and gas industry, as well as create significant new requirements and standards for new, modified and existing oil and gas facilities. The proposed new requirements would include, for example, new standards and emission limitations applicable to storage vessels, well liquids unloading, pneumatic controllers and flaring of natural gas at both new and existing facilities. 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.

Certain states have also adopted, or are considering, regulations addressing methane releases from oil and gas operations. Compliance with rules applicable to jurisdictions in which we operate could result in significant costs, including increased capital expenditures and operating costs, which may adversely impact our business.

Environmental Protection and Natural Gas Flaring. North Dakota law restricts the flaring of natural gas from wells that have not been connected to a gas gathering line for a period of one year from the date of the well's first production. After one year, an operator is required to cap the well, connect it to a gas gathering line, find acceptable alternative uses for a percentage of the flared gas or apply to the North Dakota Industrial Commission (the "NDIC") for a written exemption for any future flaring.

In addition, NDIC rules for new drilling permits require the submission of gas capture plans setting forth the operator's plan to capture and not flare produced gas, regardless of whether it has been or will be connected within the first year of production. The NDIC currently requires us to capture 91% of the natural gas produced from a field, with various allowances for, including but not limited to, initial production testing, force majeure events and temporary midstream outages. If an operator is unable to attain the applicable gas capture percentage goal at maximum efficient rate, wells will be restricted in production to 200 barrels of crude oil per day if at least 60% of the monthly volume of associated natural gas produced from the well is captured, or otherwise crude oil production from such wells is not permitted to exceed 100 barrels of crude oil per day. However, the NDIC will consider temporary exemptions from the foregoing restrictions or for other types of extenuating circumstances after notice and hearing if the effect is a significant net increase in gas capture within one year of the date such relief is granted. Monetary penalty provisions also apply under this regulation if an operator fails to timely file for a hearing with the NDIC upon being unable to meet such percentage goals or if the operator fails to timely implement

production restrictions once below the applicable percentage goals. Ongoing compliance with the NDIC's flaring requirements or the imposition of any additional limitations on flaring could result in increased costs and have an adverse effect on our operations. However, it is expected that any such change would not disparately affect us and our competitors. We believe we operated in compliance with the NDIC standards throughout 2021.

Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight rock formations. The process involves the injection of mainly water and sand plus a de minimis amount of chemicals under pressure into formations to fracture the surrounding rock and stimulate production. We expect that we will utilize hydraulic fracturing for the foreseeable future to complete or recomplete wells in areas in which we work. Hydraulic fracturing is typically regulated at the state level; however, the EPA issued guidance in 2014 to address hydraulic fracturing injections using diesel.

In addition, in June 2016, the EPA issued a final rule promulgating pretreatment standards for discharges of wastewater pollutants from onshore unconventional oil and gas extraction facilities to publicly-owned treatment works. The EPA, along with other federal agencies such as the U.S. Department of Energy, the U.S. Government Accountability Office, the U.S. Department of Interior and the White House Council for Environmental Quality continue to study various aspects of hydraulic fracturing.

In addition, legislation has been introduced in Congress from time to time to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Multiple states, including Texas, Colorado and Wyoming have already adopted rules requiring disclosures of chemicals used in hydraulic fracturing and others have enacted regulations imposing additional requirements on activities involving hydraulic fracturing. Chemical disclosure regulations may increase compliance costs and may limit our ability to use cutting-edge technology in markets where disclosure is required. Further, laws such as those restricting the use of or regulating the time, place and manner of hydraulic fracturing (such as setback ordinances) may impact our ability to fully extract reserves. No assurance can be given as to whether or not more stringent hydraulic fracturing measures might be adopted in additional jurisdictions in which our properties are located. If new laws, regulations or ordinances that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in the states or local municipalities where our properties are located, such legal requirements could prohibit or make it more difficult or costly for us to perform hydraulic fracturing activities.

Further, in May 2014, the EPA published an Advance Notice of Proposed Rulemaking under the Toxic Substances Control Act, relating to the disclosure of chemical substances and mixtures used in oil and gas exploration and production. On July 11, 2014, the EPA extended the public comment period for the rulemaking to September 18, 2014. The EPA has not yet taken further action with respect to this rule. Depending on the precise disclosure requirements the EPA elects to impose, if any, we may be obliged to disclose valuable proprietary information, and failure to do so may subject us to penalties. In addition, we may be required to disclose information of third parties, that may be inaccurate or that we may be contractually prohibited from disclosing, which could also subject us to penalties.

In addition, in July 2014, a major university and U.S. Geological Survey researchers published a study purporting to find a connection between the deep well injection of hydraulic fracturing wastewater and a sharp increase in seismic activity in Oklahoma since 2008. This study, as well as subsequent studies and reports, may trigger new legislation or regulations that would limit or ban the disposal of hydraulic fracturing wastewater in deep injection wells. If such new laws or rules are adopted, our operations may be curtailed while alternative treatment and disposal methods are developed and approved.

Global Warming and Climate Change. In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHG") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. Based on these findings, the EPA has adopted and implemented regulations that restrict emissions of GHG under existing provisions of the CAA.

At present, the EPA may establish GHG permitting requirements for stationary sources already subject to the Prevention of Significant Deterioration ("PSD") and Title V requirements of the CAA. Certain of our equipment and installations may currently be subject to PSD and Title V requirements and hence, under the U.S. Supreme Court's ruling, may also be subject to the installation of controls to capture GHGs. For any equipment or installation so subject, we may have to incur increased compliance costs to capture related GHG emissions.

In October 2016, the EPA proposed revisions to the rule applicable to GHGs for PSD and Title V permitting requirements. The public comment period for the rulemaking concluded on December 16, 2016. While no final rule has been published, this may be taken up as a priority by the Biden administration.

In August 2015, the EPA issued a rule to reduce carbon emissions from electric generating units. The rule, commonly called the "Clean Power Plan," required states to develop plans to reduce carbon emissions from fossil fuel-fired generating units commencing in 2022, with the reductions to be fully phased in by 2030. However, in February 2016, the U.S. Supreme Court stayed the implementation of the Clean Power Plan while it was being challenged in court. On October 16, 2017, the EPA published a proposed rule that would repeal the Clean Power Plan and on August 18, 2018, the EPA proposed the Affordable Clean Energy ("ACE") rule as a replacement to the Clean Power Plan. The EPA issued the final ACE rule in June 2019. As expected, over 20 states and public health and environmental

organizations challenged the rule and it was vacated on January 29, 2021. The matter has been remanded to the EPA and it is expected that the Biden administration will propose new rules in this area during the next few years.

In addition, both houses of Congress have actively considered legislation to reduce emissions of GHG, and many states have already taken legal measures to reduce emissions of GHG, primarily through the development of GHG inventories, GHG permitting and/or regional GHG "cap and trade" programs. Most of these "cap and trade" programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. In November 2021, the U.S. House of Representatives passed the H.R. 5376 bill, which would amend the CAA to impose a fee of $1,500 per ton of methane emitted above specified thresholds from onshore petroleum and natural gas production facilities, natural gas processing facilities, natural gas transmission and compression facilities, and onshore petroleum and natural gas gathering and boosting facilities, among other facilities. The U.S. Senate is currently considering H.R. 5376 and may adopt, modify, or eliminate the methane fee. Also, in recent years, lawsuits have been brought against other energy companies for matters relating to climate change. Multiple states and localities have also initiated investigations in climate-change related matters. While the current suits focus on a variety of issues, at their core they seek compensation for the effects of climate change from companies with ties to GHG emissions. It is currently unknown what the outcome of these types of actions may be, but the costs of defending against such actions may be expected to rise. Finally, it should be noted that many scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If such effects occur, they could have a material adverse effect on our assets and limit the type, timing and location of our operations.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including the Outer Continental Shelf Lands Act ("OCSLA"), the National Environmental Policy Act ("NEPA") and the Coastal Zone Management Act ("CZMA"), require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. OCSLA, for instance, requires the U.S. Department of Interior to evaluate whether certain proposed activities would cause serious harm or damage to the marine, coastal or human environment. Similarly, NEPA requires the U.S. Department of Interior and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency would have to prepare an environmental assessment and potentially an environmental impact statement. Recent federal court cases involving natural gas pipelines have involved challenges to the sufficiency of the evaluation of climate change impacts in environmental impact statements prepared under NEPA. The CZMA, on the other hand, aids states in developing a coastal management program to protect the coastal environment from growing demands associated with various uses, including offshore oil and gas development. In obtaining various approvals from the U.S. Department of Interior, we must certify that we will conduct our activities in a manner consistent with all applicable regulations.

Available Information

We maintain a website at the address www.whiting.com. We are not including the information contained on our website as part of, or incorporating it by reference into, this report. We make available free of charge (other than an investor's own Internet access charges) through our website our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, including exhibits and amendments to these reports, as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the SEC.

Item 1A. Risk Factors

Each of the risks described below should be carefully considered, together with all of the other information contained in this Annual Report on Form 10-K, before making an investment decision with respect to our securities. In the event of the occurrence, reoccurrence, continuation or increased severity of any of the risks described below, our business, financial condition or results of operations could be materially and adversely affected, and you may lose all or part of your investment.

Summary Risk Factors

The following is a summary of the material risks and uncertainties we have identified, which should be read in conjunction with the more detailed description of each risk factor contained below.

Risks Related to Our Business and Operations

- Declines in, or extended periods of low oil, NGL or natural gas prices and/or widened differentials;
- The occurrence of epidemic or pandemic diseases, including the coronavirus ("COVID-19") pandemic;
- Actions of the Organization of Petroleum Exporting Countries ("OPEC") and other oil exporting nations to set and maintain production levels;
- The potential shutdown of the Dakota Access Pipeline ("DAPL");
- The geographic concentration of our operations;
- Our potential inability to access oil and gas markets due to market conditions or operational impediments;
- Market availability of, and risks associated with, transport of oil and natural gas, which may subject us to substantial liability claims;
- Shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and completion services;
- Adverse weather conditions that may negatively impact development or production activities;
- Lack of control over non-operated properties;
- Cybersecurity attacks or failures of our telecommunication and other information technology infrastructure;
- Our level of success in development and production activities;
- Our ability to replace our oil and natural gas reserves;
- Impacts resulting from the allocation of resources among our strategic opportunities;
- Our ability to successfully complete asset acquisitions and dispositions and the risks related thereto;
- The timing of our development expenditures;
- Unforeseen underperformance of or liabilities associated with acquired properties or other strategic partnerships or investments; and
- Competition in the oil and gas industry.

Risks Related to Our Capital Structure and Financial Results

- The impacts of hedging on our results of operations and cash flows;
- Revisions to reserve estimates as a result of changes in commodity prices, regulation and other factors;
- Inaccuracies of our reserve estimates or our assumptions underlying them;
- Our ability to use net operating loss carryforwards ("NOLs") in future periods;
- Our ability to comply with debt covenants, periodic redeterminations of the borrowing base under Whiting Oil and Gas Corporation's ("Whiting Oil and Gas") Credit Agreement and our ability to generate sufficient cash flows from operations to service any indebtedness we incur;
- Our ability to generate sufficient cash flows from operations to meet the internally funded portion of our capital expenditures budget; and
- Impacts to financial statements as a result of impairment write-downs and other cash and noncash charges.

Risks Related to Government Regulations, Investor Sentiment, Corporate Governance and Legal Proceedings

- The impact and costs of compliance with laws and regulations governing our oil and gas operations;
- Impacts of local regulations, climate change issues, negative perception of our industry and corporate governance standards;
- The potential impact of changes in laws that could have a negative effect on the oil and gas industry;
- The impact of negative shifts in investor sentiment towards the oil and gas industry; and
- Negative impacts from litigation and legal proceedings.

Risks Related to Our Chapter 11 Bankruptcy

- The effect of our emergence from bankruptcy on our business and relationships;
- The fact that our historical financial results may not be comparable to our actual financial results after emergence from bankruptcy and may not be indicative of future financial performance; and
- The new securities we issued upon emergence may result in potential future dilution.

Risks Related to Our Business and Operations

Oil and natural gas prices and differentials are very volatile. An extended period of low oil and natural gas prices and/or widened differentials may adversely affect our business, financial condition, results of operations or cash flows.

The oil and natural gas markets are very volatile, and we cannot predict future oil and natural gas prices. The price we receive for our oil, NGL and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. The prices we receive for our production depend on numerous factors beyond our control, including, but not limited to, the following:

- changes in regional, domestic and global supply and demand for oil and natural gas;
- the level of global oil and natural gas inventories and storage capacity;
- the occurrence or threat of epidemic or pandemic diseases, such as the COVID-19 pandemic, or any government response to such occurrence or threat;
- the actions or inactions of OPEC;

- proximity, capacity and availability of oil and natural gas pipelines and other transportation facilities, including any court rulings which may result in the inability to transport oil on the DAPL;
- the price and quantity of imports of oil and natural gas;
- market demand and capacity limitations on exports of oil and natural gas;
- political and economic conditions, including embargoes and sanctions, in oil-producing countries or affecting other oil-producing activity, such as the U.S. imposed sanctions on Venezuela and Iran and conflicts in the Middle East;
- developments relating to North American energy infrastructure, including legislative, regulatory and court actions that may impact such infrastructure and other developments that may cause short- or long-term capacity constraints;
- the level of global oil and natural gas exploration and production activity;
- the effects of global conservation and sustainability measures;
- the effects of the global and domestic economies, including the impact of expected growth, access to credit and financial markets, the relative strength of the United States dollar compared to foreign currencies and other economic conditions;
- weather conditions and natural disasters;
- technological advances affecting energy consumption;
- current and anticipated changes to domestic and foreign governmental regulations, such as regulation of oil and natural gas gathering and transportation;
- the price and availability of competitors' supplies of oil and natural gas;
- basis differentials associated with market conditions, the quality and location of production and other factors;
- acts of terrorism;
- the price and availability of alternative fuels and energy sources; and
- force majeure events.

These factors and the volatility of the energy markets generally make it extremely difficult to predict future oil and natural gas price movements. Also, prices for crude oil, NGLs and natural gas do not necessarily move in tandem. Declines in oil, NGL or natural gas prices would not only reduce revenue, but could also reduce the amount of economically viable production and therefore potentially lower our reserve quantities. If the oil and natural gas industry experiences extended periods of low prices, we may, among other things, be unable to meet all of our financial obligations or make planned expenditures.

Substantial and extended declines in oil, NGL and natural gas prices have resulted and may continue to result in impairments of our proved oil and gas properties or undeveloped acreage and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, we will be required to reduce spending, borrow under the Credit Agreement or sell assets. Lower commodity prices may reduce the amount of our borrowing base under the Credit Agreement, which is determined at the discretion of our lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations on April 1 and October 1 of each year, as well as special redeterminations described in the Credit Agreement. Upon a redetermination, if total outstanding credit exposure exceeds the redetermined borrowing base, we could be forced to repay borrowings under the Credit Agreement.

Lower commodity prices may also reduce the proceeds we receive from the sale of assets or make it more difficult for us to comply with the covenants and other restrictions in the agreements governing our debt as described under the Risk Factor entitled "The Credit Agreement contains various covenants limiting the discretion of our management in operating our business."

Alternatively, higher oil, NGL and natural gas prices may result in significant mark-to-market losses being incurred on our commodity-based derivatives.

Additionally, the prices that we receive for our oil and natural gas production generally reflect a discount, but sometimes a premium, to relevant benchmark prices such as NYMEX. A negative or positive difference between the benchmark price and the price received is called a differential. The differential may vary significantly due to market conditions, the quality and location of production and other risk factors, as demonstrated in the fourth quarter of 2018 when our oil differentials weakened substantially. We cannot accurately predict oil and natural gas differentials. Changes in the differential and decreases in the benchmark price for oil and natural gas could have a material adverse effect on our business, financial condition, results of operations or cash flows.

The occurrence of epidemic or pandemic diseases, including the COVID-19 pandemic, could adversely affect our business, financial condition, results of operations and cash flows.

Global or national health concerns, including the outbreak of pandemic or contagious disease or its related variants, can negatively impact the global economy and, therefore, demand and pricing for oil and natural gas products. For example, the World Health Organization declared COVID-19 a pandemic in March 2020, and the continued duration and severity of the COVID-19 pandemic and its ongoing impact on our business cannot be predicted. The outbreak of communicable diseases, or the perception that such an outbreak could occur, could result in a widespread public health crisis that could adversely affect the economies and financial markets of many countries, resulting in an economic downturn that would negatively impact the demand for oil and natural gas products. Furthermore, uncertainty regarding the impact and length of any outbreak of pandemic or contagious disease, including COVID-19, can and has led to increased volatility in oil and natural gas prices. Finally, in the event that there is an outbreak of COVID-19 at any of our operating locations, we could be forced to cease operations at such locations for a period of time. The occurrence or continuation of any of these events could lead to decreased revenues and limit our ability to execute our business plan, which could adversely affect our business, financial condition, results of operations and cash flows.

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

OPEC is an intergovernmental organization that seeks to manage the price and supply of oil on the global energy market. Actions or inaction of OPEC members, including those taken alongside other oil exporting nations, have a significant impact on global oil supply and pricing. For example, OPEC and certain other oil exporting nations have previously agreed to take measures, including production cuts and increases, in an effort to achieve certain global supply or demand targets or to achieve certain crude oil price outcomes. There can be no assurance that OPEC members and other oil exporting nations will continue to agree to future production cuts, moderating future production or other actions to support and stabilize oil prices, and they may take actions that have the effect of reducing oil prices. Uncertainty regarding future actions to be taken by OPEC members or other oil exporting countries could lead to increased volatility in the price of oil, which could adversely affect our business, financial condition, results of operations and cash flows.

We transport a portion of our crude oil through the DAPL, which is subject to ongoing litigation that may result in a shutdown of the DAPL, which could adversely affect our business, financial condition, results of operations or cash flows.

On March 25, 2020, the U.S. District Court for D.C. ("D.C. District Court") found that the U.S. Army Corps of Engineers ("Army Corps") had violated the National Environmental Policy Act when it granted an easement relating to a portion of the Dakota Access Pipeline ("DAPL") because it had failed to prepare an environmental impact statement ("EIS"). As a result, in an order issued July 6, 2020, the D.C. District Court vacated the easement and directed that the DAPL be shut down and emptied of oil by August 5, 2020. After issuing a stay of the order to shut down the pipeline on August 5, 2020, the U.S. Court of Appeals for the D.C. Circuit ("D.C. Appellate Court"), on January 26, 2021, affirmed the D.C. District Court's decision to vacate the easement and concluded that the D.C. District Court must further consider whether shut down of the DAPL is an appropriate remedy while the Army Corps develops an EIS. On May 21, 2021, the D.C. District Court ruled that it would not issue an injunction requiring a shutdown of the DAPL and that the DAPL could continue to operate while the Army Corps prepares an EIS. The D.C. District Court further ruled on June 22, 2021 that the litigation be dismissed and that the plaintiffs could renew their challenge to DAPL upon the Army Corps' issuance of an EIS. Barring different discretionary action by the Army Corps, these rulings allow the DAPL's continued operation unless and until new challenges are made and succeed following issuance of the EIS, which the Army Corps anticipates issuing in the fall of 2022. On September 20, 2021, the DAPL's owner filed a petition with the U.S. Supreme Court seeking review of the lower courts' decisions requiring a new EIS and permit, and the plaintiff tribes and Army Corps filed briefs opposing such review. However, the U.S. Supreme Court declined to accept the case for review. The potential disruption of transportation as a result of the DAPL being shut down or the anticipation of the DAPL being shut down could negatively impact our ability to achieve the most favorable prices for our crude oil production, which could have an adverse effect on our business, financial condition, results of operations or cash flows. While we are coordinating with our midstream partners and downstream markets to source transportation alternatives in order to mitigate the impact of a DAPL shutdown, we cannot provide any assurance that our efforts to do so will be successful.

Substantially all of our producing properties are concentrated in the Williston Basin of North Dakota and Montana, making us vulnerable to risks associated with operating in one major geographic area.

Substantially all of our producing properties are geographically concentrated in the Williston Basin of North Dakota and Montana. At December 31, 2021, approximately 98% of our total estimated proved reserves were attributable to properties located in this area. Because of this concentration in a limited geographic area, the success and profitability of our operations may be disproportionately exposed to regional factors compared to competitors having more geographically dispersed operations. These factors include, among others: (i) the prices of crude oil and natural gas produced from wells in the region and other regional supply and demand factors, including gathering, pipeline and rail transportation capacity constraints, (ii) the availability of rigs, equipment, oilfield services, supplies and labor, (iii) the availability of processing and refining facilities and (iv) infrastructure capacity. In addition, our operations in the Williston Basin may be adversely affected by severe weather events such as floods, blizzards, ice storms, tornadoes and freezing temperatures which can intensify competition for the items and services described above and may result in periodic shortages. The concentration of our operations in a limited geographic area also increases our exposure to changes in local laws and regulations, certain lease stipulations designed to protect wildlife and unexpected events that may occur in the regions such as natural disasters, seismic events (which may result in third-party lawsuits), industrial accidents, labor difficulties, civil disturbances, public protests or terrorist attacks. Any one of these events has the potential to cause producing wells to be shut-in, delay operations, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. Any of the risks described above could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Market conditions or operational impediments may hinder our access to oil and gas markets or delay our production.

In connection with our continued development of oil and gas properties, we are exposed to the risk of delays or interruptions of production from wells on these properties caused by transportation capacity constraints, curtailment of production or the unavailability of transportation infrastructure for the oil and gas volumes produced. In addition, market conditions or a lack of satisfactory oil and gas transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil, NGL and natural gas production depends on a number of factors, including the demand for and supply of oil, NGLs and natural gas, downstream market conditions and competing supply alternatives. Our ability to market our production also depends substantially on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties and the ability to obtain such services on acceptable terms. We may be disproportionately exposed to the impact of delays or interruptions of production caused by market constraints or interruptions in transportation of our production. This could lead to production curtailments or shut-ins and reduced revenue which could materially harm our business. We may enter into arrangements for transportation services and sales to reduce curtailment risks. However, these services expose us to the risk that third parties will default on their obligations under such arrangements.

Risks associated with the production, gathering, transportation and sale of oil, NGLs and natural gas could materially and adversely affect our business, financial condition, results of operations or cash flows and may subject us to substantial liability claims.

Our financial condition, net income and cash flows will depend upon, among other things, oil, NGL and natural gas production and the prices received and costs incurred to develop and produce oil and natural gas reserves. Drilling, production or transportation accidents that temporarily or permanently halt the production and sale of oil, NGLs and natural gas will decrease revenues and increase expenditures and may subject us to liability. For example, accidents may occur that result in personal injuries, property damage, damage to productive formations or equipment and environmental damages. Any costs incurred in connection with any such accidents that are not insured against will have the effect of reducing net income. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. Also, our oil, NGL and natural gas production depends in large part on the proximity and capacity of pipeline systems and transportation facilities which are mostly owned by third parties. The lack of availability or the lack of capacity on these systems and facilities could result in the curtailment of production or the delay or discontinuance of drilling plans. Similarly, curtailments or damage to pipelines and other transportation facilities used to transport oil, NGL and natural gas production to markets for sale could decrease revenues or increase transportation expenses. Any such curtailments or damage to the gathering systems could also require us to find alternative means to transport oil, NGL and natural gas production. Such alternative means may not be available or could result in additional costs that will have the effect of increasing transportation expenses or differentials. Adverse changes in the terms and conditions of natural gas pipeline tariffs could result in increased costs or competitive disadvantages.

In addition, drilling, production and transportation of hydrocarbons bear the inherent risk of loss of containment. Potential consequences include, but are not limited to, loss of reserves, loss of production, loss of economic value associated with the affected wellbore, personal injuries and death, contamination of air, soil, ground water and surface water. We could be subject to fines, penalties or other damages associated with any event of this nature.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition, results of operations or cash flows. 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 uncontrollable flows of oil, gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- the loss of well control;
- fires and explosions;
- personal injuries and death;
- terrorist attacks; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, then it could adversely affect us.

The unavailability or cost of additional drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis or within our budget.

The demand for qualified and experienced field personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices or economic trends in the broader economy, causing periodic shortages. Historically, there have been shortages of drilling rigs, completion crews and other oilfield equipment as demand for these items has increased along with the number of wells being drilled and completed. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs and other oilfield goods and services. Shortages of field personnel and other professionals, drilling rigs, completion crews, equipment or supplies, and any resulting price increases, could delay or adversely affect our exploration and development operations, which could restrict such operations or have a material adverse effect on our business, financial condition, results of operations or cash flows.

Adverse weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and gas operations in the Rocky Mountains are adversely affected by weather conditions and lease stipulations designed to protect various wildlife. In certain areas, drilling and other oil and gas activities can only be conducted during certain months due to severe weather. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. Resulting shortages or high costs could delay our operations, cause temporary declines in our oil and gas production and materially increase our operating and capital costs and reduce our cash flows. Severe weather events may increase in duration and intensity as a result of climate change, in which case these risks will be greater in the future.

We have limited control over activities on properties we do not operate, which could increase capital expenditures.

We operate 88% of our net productive oil and natural gas wells, which represents 92% of our proved developed producing reserves as of December 31, 2021. If we do not operate the properties in which we own an interest, we do not have control over normal capital expenditures or future development of those properties. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's decisions with respect to the timing and amount of capital expenditures, the period of time over which the operator seeks to generate a return on capital expenditures, inclusion of other participants in drilling wells, the use of technology, as well as the operator's expertise and financial resources and the operator's relative interest in the field. Accordingly, while we use reasonable efforts to cause the operator to act in a prudent manner, we are limited in our ability to do so.

We depend on computer and telecommunications systems, and failures in our systems or cybersecurity attacks could have a material adverse effect on our business, financial condition, results of operations or cash flows.

Our business has become increasingly dependent upon digital technologies to conduct day-to-day operations, including information systems, infrastructure and cloud applications. We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. In addition, we have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. We rely on such systems to process, transmit and securely store electronic information, including financial records, banking information and personally identifiable information such as contractor, investor and payroll data, and to manage or support a variety of business processes, including our supply chain, pipeline operations, gathering and processing operations, financial transactions, banking and numerous other processes and transactions.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks and unintentional events, also have increased in frequency. A cyber-attack could include unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. It is possible that we could incur interruptions or loss of data from cybersecurity attacks, computer viruses or malware, or that third-party service providers could cause a breach of our data. Any interruptions to our arrangements with third parties for our computing and communications infrastructure or any other interruptions to, or breaches of, our information systems could lead to data corruption, communication interruption, loss of sensitive or confidential information or otherwise significantly disrupt our business operations.

Strategic targets, such as energy-related assets and transportation assets, may be at greater risk of future cyber-attacks than other targets. The various procedures, facilities, infrastructure and controls we utilize to monitor these threats and mitigate our exposure to such threats are costly and labor intensive. Moreover, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. We do not expect to obtain or maintain specialized insurance for possible liability or loss resulting from a cyber-attack on our assets that may shut down all or part of our business. However, as cyber threats 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 information security vulnerabilities. State and federal cybersecurity legislation could also impose new requirements, which could increase our cost of doing business.

To our knowledge we have not experienced any material losses relating to cyber-attacks; however, there can be no assurance that we will not suffer material losses in the future either as a result of an interruption to or a breach of our systems or those of our third-party vendors and service providers. A cyber incident involving our information systems and related infrastructure, or that of third parties, could disrupt our business plans and negatively impact our operations in the following ways, among others, any of which could have a material adverse effect on our reputation, business, financial condition, results of operations or cash flows:

- unauthorized disclosure of sensitive or personally identifiable information, including by cyber-attacks or other security breaches, could cause loss of data, give rise to remediation or other expenses, expose us to liability under federal and state laws, reduce our customers' willingness to do business with us, disrupt the services we provide to customers and property owners and subject us to litigation and investigations;

- a cyber-attack on a third party could result in supply chain disruptions which could delay or halt development of additional infrastructure, effectively delaying the start of cash flow from the project;

- a cyber-attack on downstream or midstream pipelines could prevent us from delivering product, resulting in a loss of revenues;

- a cyber-attack on a communications network or power grid could cause operational disruption resulting in a loss of revenues;

- a deliberate corruption of our financial or operational data could result in events of non-compliance which could lead to regulatory fines or penalties; and

- business interruptions could result in expensive remediation efforts, distraction of management, damage to our reputation, or a negative impact on the price of our common shares.

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

Our future success will depend on the success of our development and production activities. Our oil and natural gas development 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 or that production will fall short of our estimates. Our decisions to purchase, explore, develop or otherwise exploit prospects 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. Refer to the Risk Factor entitled "Reserve estimates depend on many assumptions that may turn out to be inaccurate..." for a discussion of the uncertainty involved in these processes. 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 or, even if economical, less successful than we projected. Further, many factors may curtail, delay or cancel drilling, including, but not limited to, the following:

- substantial or extended declines in oil, NGL and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- delays in or limits on the issuance of drilling permits by state agencies or on our federal leases, including as a result of government shutdowns;
- pressure or irregularities in geological formations;
- limitations in infrastructure, including pipeline takeaway and refining and processing capacity;
- shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and completion services;
- equipment failures, accidents, fires and explosions, including ruptures of pipelines or storage facilities or train derailments;
- adverse weather events, such as floods, blizzards, ice storms, tornadoes and freezing temperatures; and
- title defects.

Unless we replace our oil and natural gas reserves, our reserves and production will decline and we may not be able to sustain production.

Unless we conduct successful development and production activities or acquire properties containing proved reserves, our proved reserves will decline over time. Producing oil and natural gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and producing our current reserves and finding economically recoverable or acquiring additional economically recoverable reserves. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources to acquire attractive companies or properties. Therefore, we may not be able to develop, find or acquire additional reserves to sustain or replace our current and future production, which could adversely affect our business, financial condition, results of operations or cash flows.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging, and a failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our business, financial condition, results of operations or cash flows.

Our future growth prospects are dependent upon our ability to identify optimal strategies for investing our capital resources to produce favorable rates of return. In developing our business plan, we consider allocating capital and other resources to various aspects of our business including well development (primarily drilling), reserve acquisitions, corporate items and other alternatives. We also consider our likely sources of capital, including cash generated from operations and borrowings under the Credit Agreement. Notwithstanding the determinations made in the development of our business plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and future growth may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our business plan and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

Part of our business strategy includes selling properties and this subjects us to various risks.

Part of our business strategy includes selling properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own. However, there is no assurance that such sales will occur in the time frames or with the economic terms we expect. Unless we conduct successful exploration, development and production activities or acquire properties containing proved reserves, divestitures of our properties will reduce our proved reserves and potentially our production. We may not be able to develop, find or acquire additional reserves sufficient to replace such reserves and production from any of the properties we sell. Additionally, agreements pursuant to which we sell properties may include terms that survive closing of the sale, including but not limited to indemnification provisions, which could result in us retaining substantial liabilities.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These scheduled drilling locations represent a significant part of our business strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability of capital, costs of oil field goods and services, drilling results, our ability to extend drilling acreage leases beyond expiration, regulatory approvals and other factors. 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 gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from our current plan, and this could adversely affect our business, financial condition, results of operations or cash flows or require us to remove certain proved undeveloped reserves from our proved reserve base if we are unable to drill PUD locations within the SEC’s prescribed 5-year window.

Properties that we acquire may not produce as projected, and we may be unable to identify liabilities associated with the properties or obtain indemnities from sellers for liabilities they may have created.

Our business strategy includes a continuing acquisition program. The successful acquisition of producing properties requires assessment of many factors, which are inherently inexact and may be inaccurate, including, but not limited to, the following:

- the anticipated levels of recoverable reserves, earnings or cash flow;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- timing of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- the assumption of unknown potential environmental and other liabilities, losses or costs, including but not limited to title defects, historical spills or releases for which we are not indemnified or for which our indemnity is inadequate.

Furthermore, acquisitions pose substantial risks to our business, financial condition, results of operations and cash flows. The risks associated with acquisitions, either completed or future acquisitions, include, but are not limited to:

- we may be unable to integrate acquired businesses successfully and to realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures; and
- we may issue additional equity or debt securities in order to fund future acquisitions.

Our assessment of a potential acquisition will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform, facility or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination, when they are made. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

We expect to consider from time to time further strategic opportunities that may involve acquisitions, dispositions, investments in joint ventures, partnerships, and other strategic alternatives that may enhance shareholder value, any of which may result in the use of a significant amount of our management resources or significant costs, and we may not be able to fully realize the potential benefit of such transactions.

We expect to continue to consider acquisitions, dispositions, investments in joint ventures, partnerships, and other strategic alternatives with the objective of maximizing shareholder value. Our Board and our management may from time to time be engaged in evaluating potential transactions and other strategic alternatives. In addition, from time to time, we may engage financial advisors, enter into non-disclosure agreements, conduct discussions, and undertake other actions that may result in one or more transactions. Although there would be uncertainty that any of these activities or discussions would result in definitive agreements or the completion of any transaction, we may devote a significant amount of our management resources to analyzing and pursuing such a transaction, which could negatively impact our operations, and may impair our ability to retain and motivate key personnel. In addition, we may incur significant costs in connection with seeking such transactions or other strategic alternatives regardless of whether the transaction is completed. In the event that we consummate an acquisition, disposition, partnership or other strategic transaction in the future, we cannot be certain that we would fully realize the potential benefit of such a transaction and cannot predict the impact that such strategic transaction might have on our operations or stock price. Any potential transaction would be dependent upon a number of factors that may be beyond our control, including, among other factors, market conditions, industry trends, regulatory limitations and the interest of third parties in us and our assets. There can be no assurance that the exploration of strategic alternatives will result in any specific action or transaction. Further, any such strategic alternative may not ultimately lead to increased shareholder value. We do not undertake to provide updates or make further comments regarding the evaluation of strategic alternatives, unless otherwise required by law.

Competition in the oil and gas industry and from alternative energy sources is intense, which may adversely affect our ability to achieve our strategic goals.

We operate in a highly competitive environment for acquiring properties, obtaining investment capital, securing oilfield goods and services, marketing oil and natural gas products and attracting and retaining qualified personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our resources allow. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation or regulation enacted by state, local and U.S. government bodies and their associated agencies, especially with regards to environmental protection and climate-related policies. Such laws and regulations may substantially increase the costs of exploring for or developing or producing oil and natural gas and our larger competitors may be able to better absorb the burden of such legislation and regulation, which would also adversely affect our competitive position. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

We also face indirect competition from alternative energy sources, such as wind, solar, nuclear, hydrogen and electric power. The proliferation of alternative energy sources and businesses that provide such alternative energy sources may decrease the demand for oil and natural gas products. These alternative energy sources may increase in the future in response to concerns about climate change or the enactment of climate-related policies. Decreased demand for our products could adversely affect our business, financial condition, results of operations or cash flows.

Risks Related to Our Capital Structure and Financial Results

Our use of oil, natural gas and natural gas liquids price hedging contracts involves only a portion of our anticipated production, may limit higher cash flows in the future in connection with commodity price increases and may result in significant fluctuations in our net income.

We enter into hedging transactions relating to our oil, natural gas and NGL production to reduce our exposure to fluctuations in the price of oil, natural gas and NGLs. Our hedging transactions to date have consisted of financially settled crude oil, natural gas and NGL options contracts, primarily two-way collars and swaps, placed with major financial institutions. As of February 17, 2022, we had crude oil derivative contracts (consisting of collars and swaps) covering the sale of 39,000 Bbl and 16,000 Bbl of oil per day for the remainder of 2022 and the first three quarters of 2023, respectively. Additionally, we had natural gas derivative contracts (consisting of collars, swaps and basis swaps) covering the sale of 95,000 MMBtu and 61,000 MMBtu of natural gas per day through the remainder of 2022 and first three quarters of 2023, respectively. Finally, we had NGL derivative contracts (consisting of swaps) covering the sale of 223,000 gallons of NGLs per day for the remainder of 2022. Refer to "Quantitative and Qualitative Disclosures about Market Risk" in Item 7A and the "Derivative Financial Instruments" footnote of the consolidated financial statements in Item 8 of this Annual Report on Form 10-K for pricing information and a more detailed discussion of our hedging transactions.

We may in the future enter into these and other types of hedging arrangements to reduce our exposure to fluctuations in the market prices of oil, natural gas and NGLs, or alternatively, we may decide to unwind or restructure the hedging arrangements we previously entered into. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions may limit the benefit we may otherwise receive from increases in the price for oil, natural gas and NGLs. Furthermore, if we are party to hedging transactions that cover a smaller percentage of our production than our competitors, we may be more adversely affected by declines in oil and natural gas prices than those competitors. Additionally, hedging transactions may expose us to cash margin requirements.

We recognize all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income (loss). Consequently, we may experience significant net losses, on a non-cash basis, due to changes in the value of our hedges as a result of commodity price volatility. Additionally, settlements paid on hedging arrangements may significantly decrease our cash flow from operating activities in periods where current commodity prices are higher than the ceilings or swap price of certain hedging arrangements.

Also, in 2010, the U.S. Congress adopted the Dodd-Frank Act, which, among other provisions, established federal oversight and regulation of the over-the-counter derivatives market. The regulations could increase the cost of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure existing derivative contracts, lead to fewer potential counterparties, and increase our exposure to less creditworthy counterparties, any of which could limit our desire and ability to implement commodity price risk management strategies. If our use of derivatives becomes limited as a result of the regulations, our results of operations may become more volatile and our cash flows may be less predictable. Certain aspects of the Dodd-Frank rulemaking have been repealed or have not been finalized and the ultimate effect of the regulations on our business remains uncertain.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material 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 is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves referred to in this Annual Report on Form 10-K.

In order to prepare our estimates, we must project production rates and 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 the following, among others:

- historical production from the area compared with production rates from other producing areas;
- the assumed effect of governmental regulation; and
- assumptions about future prices of oil, NGLs and natural gas including differentials, production and development costs, gathering and transportation costs, severance and excise taxes, capital expenditures and availability of funds.

Therefore, estimates of oil and natural gas reserves are inherently imprecise. Actual future production, oil, NGL and natural gas prices, revenues, taxes, exploration and development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves referred to in this Annual Report on Form 10-K. 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.

You should not assume that the present value of future net revenues from our proved reserves, as referred to in this report, is the current market value of our estimated proved oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on 12-month average prices and current costs as of the date of the estimate. The 12-month average prices used for the year ended December 31, 2021 were $66.56 per Bbl of oil and $3.60 per MMBtu of natural gas. Actual future prices and costs may differ materially from those used in the estimate. If the 12-month average oil prices used to calculate our oil reserves were $1.00 per Bbl lower, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2021 would have decreased by $71 million. If the 12-month average natural gas prices used to calculate our natural gas reserves were $0.10 per MMBtu lower, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2021 would have decreased by $17 million.

Our ability to use our NOLs in future periods may be limited.

As of December 31, 2021, we had U.S. federal NOLs of $3.3 billion, the majority of which will expire between 2022 and 2037, if not limited by triggering events prior to such time. Under the provisions of the Internal Revenue Code ("IRC"), changes in our ownership, in certain circumstances, will limit the amount of U.S. federal NOLs that can be utilized annually in the future to offset taxable income. In particular, Section 382 of the IRC imposes limitations on a company's ability to use NOLs upon certain changes in such ownership. As a result of the chapter 11 reorganization and related transactions, we experienced an ownership change within the meaning of IRC Section 382 that subjected certain of our tax attributes, including NOLs, to an IRC Section 382 limitation. Calculations pursuant to Section 382 of the IRC can be very complicated and no assurance can be given that upon further analysis, our ability to take advantage of our NOLs may be limited to a greater extent than we currently anticipate. If we are limited in our ability to use our NOLs in future years in which we have taxable income, we will pay more taxes than if we were able to utilize our NOLs fully, which could have a negative impact on our financial position and results of operations. Additionally, we may experience ownership changes in the future as a result of subsequent shifts in our stock ownership that we cannot predict or control that could result in further limitations being placed on our ability to utilize our federal NOLs.

The Credit Agreement contains various covenants limiting the discretion of our management in operating our business.

The Credit Agreement contains various restrictive covenants that may limit our management's discretion in certain respects. In particular, the agreement limits our and our subsidiaries' ability to, among other things:

- prepay, redeem or repurchase certain debt;
- pay dividends or make other distributions or repurchase or redeem our capital stock;
- make loans and investments;
- incur or guarantee additional indebtedness or issue preferred stock;
- create certain liens;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- sell assets;
- consolidate, merge or transfer all or substantially all of our assets and those of our restricted subsidiaries taken as a whole;
- engage in transactions with affiliates;
- enter into hedging contracts; and
- create unrestricted subsidiaries.

The Credit Agreement requires us, as of the last day of any quarter, to maintain commodity hedges covering a minimum of 50% of our projected production for the succeeding twelve months. If our consolidated net leverage ratio equals or exceeds 1.0 to 1.0 as of the last day of any fiscal quarter we will also be required to hedge 35% of our projected production for the next succeeding twelve months. We are also limited to hedging a maximum of 85% of our production from proved reserves. In addition, the Credit Agreement requires us, as of the last day of any quarter to maintain the following ratios (as defined in the Credit Agreement): (i) a consolidated current assets to consolidated current liabilities ratio of not less than 1.0 to 1.0 and (ii) a total debt to last four quarters' EBITDAX ratio of not greater than 3.5 to 1.0. Factors that may adversely affect our ability to comply with these covenants include oil or natural gas price declines, lack of liquidity in property and capital markets and our inability to execute on our development plan.

Moreover, the borrowing base limitation in the Credit Agreement is redetermined on April 1 and October 1 of each year and may be the subject of special redeterminations described in the Credit Agreement based on an evaluation of our oil and gas reserves. Because oil and gas prices are principal inputs into the valuation of our reserves, if oil and gas prices decline, our borrowing base could be reduced at the next redetermination date or during future redeterminations. Upon a redetermination, if total outstanding credit exposure exceeds the redetermined borrowing base, we will be required to prepay outstanding borrowings under the Credit Agreement and we may not have, or be able to obtain, the funds necessary to do so.

Our debt level and the covenants in the Credit Agreement could negatively impact our financial condition, results of operations, cash flows and business prospects.

As of December 31, 2021, we had no borrowings and $1 million in letters of credit outstanding under the Credit Agreement with $749 million of available borrowing capacity. The Credit Agreement matures on April 1, 2024. We are allowed to incur additional indebtedness, provided that we meet certain requirements in the Credit Agreement.

Our level of indebtedness and the covenants contained in the agreements governing our debt could have important consequences for our operations, including, but not limited to:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;
- increasing the possibility that we may be unable to generate sufficient cash to pay, when due, the principal of, interest on or other amounts due or otherwise refinance our indebtedness;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- placing us at a competitive disadvantage relative to other less leveraged competitors;
- making us vulnerable to increases in interest rates, because debt under the Credit Agreement is subject to certain rate variability;
- making us more vulnerable to economic downturns and adverse developments in our industry or the economy in general, especially declines in oil and natural gas prices; and
- reducing our borrowing base when oil and natural gas prices decline and our ability to maintain compliance with our financial covenants becomes more difficult, which may reduce or eliminate our ability to fund our operations.

Should we have borrowings outstanding under the Credit Agreement in the future, we may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of our repayment of any outstanding debt. Refer to the Risk Factor entitled "The Credit Agreement contains various covenants limiting the discretion of our management in operating our business."

Our development operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures through a combination of internally generated cash flows, equity and debt issuances, bank borrowings, agreements with industry partners and oil and gas property divestments. We intend to finance future capital expenditures substantially with cash flow from operations, cash on hand and borrowings under the Credit Agreement, although we may seek capital from additional sources as needed. Our cash flow from operations and access to capital is subject to a number of variables, including, but not limited to:

- the prices at which oil and natural gas are sold;
- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the costs of producing oil and natural gas; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under the Credit Agreement decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves, or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels.

We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing. Disruptions in the capital and credit markets, particularly in the energy sector, could limit our ability to access these markets or may significantly increase our cost to borrow. If cash generated by operations or availability under the Credit Agreement is not sufficient to meet our capital requirements, the inability to access the cash and credit markets to obtain additional financing, on favorable terms or otherwise, could result in a curtailment of our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves.

If we are unable to generate enough cash flow from operations to service any indebtedness we incur or are unable to use future borrowings to fund other capital needs, we may have to undertake alternative financing plans, which may have onerous terms or may be unavailable.

Our earnings and cash flow could vary significantly from year to year due to the volatility of oil and natural gas prices. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our commitments, including any indebtedness that we may incur in the future under the Credit Agreement or other arrangements. A range of economic, competitive, business and industry factors will affect our future financial performance and, as a result, our ability to generate cash flow from operations and meet our obligations. Factors that may cause us to generate cash flow that is insufficient to meet our obligations include events and risks related to our business, many of which are beyond our control. Any cash flow insufficiency would have a material adverse impact on our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance any debt. If we do not generate sufficient cash flow from operations to service any indebtedness we incur, we may be required to undertake various alternative financing plans, which may include:

- refinancing or restructuring all or a portion of our debt;
- seeking alternative financing or additional capital investment;
- selling strategic assets;
- reducing or delaying capital investments; or
- revising or delaying our strategic plans.

We cannot assure you that we would be able to implement any of the above alternative financing plans, if necessary, on commercially reasonable terms or at all. If we incur indebtedness in the future and cannot make scheduled payments on that indebtedness or otherwise fail to comply with the covenants and other restrictions in the agreements governing our debt, we will be in default and the lenders under the Credit Agreement could declare all outstanding principal and interest to be due and payable. Additionally, the lenders under the Credit Agreement could terminate their commitments to loan money and could foreclose against our assets collateralizing our

borrowings, and we could be forced into bankruptcy or liquidation. If the amounts outstanding under our Credit Agreement were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full the amounts owed to the lenders. Our inability to generate sufficient cash flows to satisfy our debt obligations, or to refinance our indebtedness on commercially reasonable terms or at all, would materially and adversely affect our business, financial position, results of operations and cash flows.

If oil, NGL and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and gas properties.

Accounting rules require that we periodically review the carrying value of our producing oil and gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews (which may include depressed oil, NGL and natural gas prices and the continuing evaluation of development plans, production data, economics, possible asset sales and other factors) we may be required to write down the carrying value of our oil and gas properties. For example, we recorded $4.1 billion in impairment charges during 2020 for the partial write-downs of our Williston Basin resource play. A write-down constitutes a non-cash charge to earnings. We may incur additional impairment charges in the future, which could have a material adverse effect on our business, financial condition or results of operations in the period recognized.

Risks Related to Governmental Regulations, Investor Sentiment, Corporate Governance and Legal Proceedings

We are subject to complex laws that can affect the cost, manner or feasibility of doing business and under which we may be subject to substantial liability. The regulatory environment in which we operate changes frequently and may do so in ways that are detrimental to our business.

Development, production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include, but are not limited to:

- discharge permits for drilling operations;
- drilling bonds and permits;
- reports concerning operations;
- hydraulic fracturing;
- well spacing and setbacks;
- unitization and pooling of properties;
- environmental protection;
- worker health and safety; and
- taxation.

A summary of the most significant laws and regulations to which we are currently subject is set forth in “Business—Government Regulation.” Under these laws and regulations, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties and litigation. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition, results of operations or cash flows. For instance, an accidental release from one of our wells could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. In addition, strict liability or joint and several liability may be imposed under certain laws, which could cause us to become liable for the conduct of others or for consequences of actions that were legal when taken. Private parties, including the surface owners of properties upon which we drill, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws. We may not be able to recover some or any of these costs from insurance. Moreover, federal law and some state laws allow the government to place a lien on real property for costs incurred by the government to address contamination on the property.

These laws and regulations can also increase our costs and limit our business activities. For example, these laws and regulations may require the acquisition of a permit before drilling commences; restrict the types, quantities and concentration of materials that can be released into the environment; and limit or prohibit drilling or well completion activities on certain lands. We incur significant costs in our efforts to comply with applicable laws and regulations.

The regulatory environment in which we operate changes frequently, often through the imposition of new or more stringent environmental and other requirements, some of which may apply retroactively. We cannot predict the nature, timing, cost or effect of such additional requirements, but they may have a variety of adverse effects on us. Refer to "Business—Government Regulation" in Item 1 of this Annual Report on Form 10-K for a discussion of some potential regulatory changes that could affect our business.

Issues surrounding climate change and greenhouse gas emissions could result in increased operating costs and reduced demand for oil and gas that we produce.

Continuing and increasing political, social and scientific attention to the issue of climate change has resulted in legislative, regulatory and other initiatives, including international agreements, to reduce greenhouse gas ("GHG") emissions such as carbon dioxide and methane. Policy makers and regulators at the federal and state levels have already imposed, or stated intentions to impose, laws and regulations designed to quantify and limit the emissions of GHG. Refer to "Business—Government Regulation—Global Warming and Climate Change" in Item 1 of this Annual Report on Form 10-K for a discussion of certain existing and proposed laws and regulations intended to address climate change issues. Existing and future laws and regulations relating to climate change and GHG emissions could increase our costs, reduce demand for our products, limit our growth opportunities, impair our ability to develop our reserves and have other adverse effects on our business.

Also, in recent years, lawsuits have been brought against other energy companies for matters relating to climate change. Multiple states and localities have also initiated investigations in climate-change related matters. While the current suits focus on a variety of issues, at their core they seek compensation for the effects of climate change from companies with ties to GHG emissions. It is currently unknown what the outcome of these types of actions may be, but the costs of defending against such actions may rise.

In addition, many scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If such effects occur, they could have a material adverse effect on our business, financial condition, results of operations and cash flows, and could also limit the type, timing and location of our operations.

Finally, increased demand for low-carbon or renewable energy sources from consumers could reduce the demand for, and the price of, the products we produce. Technological changes, such as developments in renewable energy and low-carbon transportation, could also adversely affect demand for our products.

Negative public perception regarding us and/or our industry could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, waste disposal, oil spills, natural gas flaring, seismic activity, climate change, explosions of natural gas transmission lines and the development and operation of pipelines and other midstream facilities 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.

A low ESG or sustainability score could result in the exclusion of our common shares from consideration by certain investment funds and a negative perception of us by certain investors.

Certain organizations that provide corporate governance and other corporate risk information to investors and shareholders have developed scores and ratings to evaluate companies and investment funds based upon environmental, social and governance ("ESG") or sustainability metrics. Currently, there are no universal standards for such scores or ratings, but the importance of sustainability evaluations is becoming more broadly accepted by investors and shareholders. Many investment funds focus on positive ESG business practices and sustainability scores when making investments. In addition, investors, particularly institutional investors, use these scores to benchmark companies against their peers and if a company is perceived as lagging, these investors may engage with companies to require improved ESG disclosure or performance. Moreover, certain members of the broader investment community may consider a company's sustainability score as a reputational or other factor in making an investment decision. Consequently, a low sustainability score could result in exclusion of our common shares from consideration by certain investment funds, engagement by investors seeking to improve such scores and a negative perception of us by certain investors.

A negative shift in investor sentiment regarding the oil and gas industry could adversely affect our ability to raise debt and equity capital.

Certain segments of the investor community have developed negative sentiment towards investing in our industry. Historic 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 adopted policies to divest holdings in the oil and gas sector based on 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 acquisitions or development projects, impacting our future financial results.

We may be negatively impacted by litigation and legal proceedings, including ongoing claims in connection with the Chapter 11 Cases.

We are subject from time to time, and in the future may become subject, to litigation claims. These claims and legal proceedings are typically claims that arise in the normal course of business and include, without limitation, claims relating to environmental, safety and health matters, commercial or contractual disputes with suppliers and customers, claims regarding ownership of mineral interests, including from royalty owners, claims regarding acquisitions and divestitures, regulatory matters and employment and labor matters. We may also become subject to governmental or regulatory proceedings. The outcome of such claims and legal proceedings cannot be predicted with certainty and some may be resolved unfavorably to us. In addition, the claims resolutions process in connection with our previous filing for and emergence from the voluntary cases under chapter 11 of the Bankruptcy Code (the "Chapter 11 Cases") is ongoing and certain of these claims remain subject to the jurisdiction of the Bankruptcy Court. To the extent that these legal proceedings result in claims being allowed against us, such general unsecured claims may be satisfied through the issuance of shares of our common stock or other remedy or agreement under and pursuant to the Plan. As discussed in more detail in the "Commitments and Contingencies" footnote in the notes to the consolidated financial statements in Item 8 of this Annual Report on Form 10-K under the heading "Chapter 11 Cases," it is possible with respect to certain claims that we could be required or may have the option to make cash payments to resolve claims instead of issuing shares of our common stock or establish reserves and accrue liabilities with respect to such claims at a future date. Alternatively, the resolution of certain claims related to contract rejections or other general unsecured claims may result in the dilution of existing stockholders' interest. Refer to the Risk Factor entitled "The exercise of all or any number of outstanding Warrants, the issuance of stock-based awards or the issuance of our common stock to settle the claims of general unsecured claimants may dilute your holding of shares of our common stock" for a discussion of the risks involved in the resolution of certain bankruptcy claims. We may not have insurance that covers such claims and legal proceedings. Successful claims or litigation against us for significant amounts could have a material adverse effect on our reputation, business, financial condition, results of operations and cash flows. Further, even if we are successful in resolving a claim or legal proceeding, the process will require the attention of members of our senior management, reducing the time they have available to devote to managing our business, and may require us to incur substantial legal expenses.

Risks Related to Our Emergence from Chapter 11 Bankruptcy

We previously emerged from bankruptcy, which may adversely affect our business and relationships.

It is possible that our having filed for bankruptcy and our previous emergence from the Chapter 11 Cases may adversely affect our business and relationships with customers, vendors, contractors, employees or suppliers. For example:

- key suppliers, vendors or other contractual counterparties may require additional financial assurances or enhanced performance from us or demand increased fees for their goods or services;
- our ability to renew existing contracts and compete for new business may be adversely affected;
- our ability to attract, motivate and/or retain key employees and executives may be adversely affected;
- landowners may not be willing to lease acreage to us; and
- competitors may take business away from us and our ability to attract and retain customers may be negatively impacted.

The occurrence of one or more of these events could have a material and adverse effect on our operations, financial condition and reputation. We cannot assure you that having been subject to bankruptcy protection will not adversely affect our operations in the future.

Our actual and future financial results after emergence from bankruptcy may not be comparable to our historical financial information as a result of the implementation of our chapter 11 plan of reorganization (the "Plan") and the transactions contemplated thereby.

Our capital structure was significantly impacted by the Plan. Under fresh start accounting rules that applied to us upon our emergence from the Chapter 11 Cases on September 1, 2020 (the "Emergence Date"), assets and liabilities were adjusted to fair values. Accordingly, because fresh start accounting rules applied, our current and future financial condition and results of operations following the Emergence Date from the Chapter 11 Cases will not be comparable to the financial condition and results of operations reflected in our historical financial statements prior to the Emergence Date.

The exercise of all or any number of outstanding Warrants, the issuance of stock-based awards or the issuance of our common stock to settle the claims of general unsecured claimants may dilute your holding of shares of our common stock.

As of the date of filing this report, we have outstanding Warrants (as defined in the "Shareholders' Equity" footnote in the notes to the consolidated financial statements in Item 8 of this Annual Report on Form 10-K under the heading "Warrants") to purchase approximately 7.3 million shares of our common stock at exercise prices of either $73.44 or $83.45 per share. In the event that a holder of Warrants elects to exercise their option to acquire shares of common stock, we shall issue a net number of exercised shares of common stock. In addition, as of December 31, 2021, approximately 2.1 million shares of our common stock remained available for grant under the Whiting Petroleum Corporation 2020 Equity Incentive Plan. We also reserved approximately 3.0 million shares of our common stock for potential future distribution to certain general unsecured claimants for claims pending resolution in the Bankruptcy Court. In February 2021, we issued 948,897 shares out of this reserve to a general unsecured claimant in full settlement of such claimant's claims pending before the Bankruptcy Court and for rejection damages relating to an executory contract. Refer to the "Shareholders' Equity" footnote in the notes to the consolidated financial statements for more information. The exercise of the Warrants, the issuance or exercise of equity awards that we may grant in the future, the issuance of our common stock to general unsecured claimants or the sale of shares of our common stock issued for other reasons would dilute the interests of existing shareholders and could have a material adverse effect on the market for our common stock, including the price that an investor could obtain for their shares.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Summary of Oil and Gas Properties and Projects

North Dakota and Montana

Our North Dakota and Montana operations primarily include our properties in the Williston Basin targeting the Bakken and Three Forks formations and encompassing approximately 731,100 gross (479,700 net) developed and undeveloped acres as of December 31, 2021. Our estimated proved reserves in North Dakota and Montana as of December 31, 2021 were 320.3 MMBOE (57% oil), which represented 98% of our total estimated proved reserves and contributed 91.6 MBOE/d of average daily production in the fourth quarter of 2021.

We have focused our capital programs on drilling and workover opportunities that we believe provide the greatest well-level returns in order to maintain consistent production levels and generate free cash flow, while selectively pursuing acquisitions that complement our existing core properties. During 2021, we focused on high-return projects in our asset portfolio that generated significant cash flow from operations. As of December 31, 2021, we had two active drilling rigs and one completion crew working in the Williston Basin and we plan to maintain this level of activity in the area for the majority of 2022.

Across our acreage in the Williston Basin, we have implemented completion designs specifically tailored to unique reservoir conditions to increase well performance while reducing cost. We plan to continue to use this data-driven approach to completion designs on wells we drill and complete in 2022. Additionally, we plan to continue our focus on reducing time-on-location and total well cost while maximizing our lateral footage through drilling best practices including utilizing top tier drilling rigs, advanced downhole motor and drill bit technology and our custom drilling fluid system.

Additionally, we have developed an internal workflow to capture the complexities of infill drilling and the correlated impacts of legacy well production on new well performance. As a result of the analysis and modeling of more than 45 operated infill wells over the past five years, we can now more accurately predict future well performance based on offset well production data and reservoir properties. This allows us to make the best value-based decisions regarding the development of our Sanish field.

Colorado

As discussed in “Acquisitions and Divestitures” in Item 1 of this Annual Report on Form 10-K, on September 23, 2021 we completed the divestiture of all of our interests in the producing assets and undeveloped acreage, including the associated midstream assets, of our Redtail field located in the Denver-Julesburg Basin of Weld County, Colorado for aggregate sales proceeds of $171 million (before closing adjustments).

Other Non-Core Properties

Whiting USA Trust II. On December 31, 2021, the net profits interest (“NPI”) conveyed to Whiting USA Trust II (“Trust II”) on March 28, 2012 terminated. Upon termination, the NPI in the underlying properties, which received 90% of the net cash proceeds from the sale of oil and natural gas production from the underlying properties prior to its termination, reverted to Whiting. As of December 31, 2021, the NPI included interests in 1,305 gross (364.4 net) producing wells. The incremental production from the underlying properties that reverted to Whiting upon termination was approximately 2.0 MBOE/d based on production during the fourth quarter of 2021. The incremental LOE expense that reverted to Whiting upon termination was approximately $2 million. The asset retirement obligations for these properties were not conveyed to Trust II and have therefore been included in our consolidated financial statements for all periods presented. Additionally, the reserves disclosed in this Annual Report on Form 10-K contemplate the reversion of the NPI on December 31, 2021.

Reserves

As of December 31, 2021 and 2020, all of our oil and gas reserves were attributable to properties within the United States. A summary of our proved oil and gas reserves as of December 31, 2021 and 2020 based on average fiscal-year prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the respective 12-month periods) is as follows:

	Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total (MBOE)
2021				
Proved developed reserves	148,317	55,006	351,914	261,975
Proved undeveloped reserves	40,287	11,359	74,135	64,002
Total proved reserves	188,604	66,365	426,049	325,977
2020				
Proved developed reserves	128,227	37,961	251,316	208,074
Proved undeveloped reserves	35,042	8,406	52,301	52,165
Total proved reserves	163,269	46,367	303,617	260,239

Proved reserves. Estimates of proved developed and undeveloped reserves are inherently imprecise and are continually subject to revision based on production history, results of additional development, price changes, engineering and reservoir analysis and other factors.

Total extensions and discoveries of 20.3 MMBOE in 2021 were primarily attributable to successful drilling in the Williston Basin. New wells drilled in this area, as well as the proved undeveloped ("PUD") locations added as a result of offsetting drilling, increased our proved reserves.

Purchases of minerals in place totaled 15.9 MMBOE during 2021 and were primarily attributable to two acquisitions in the Williston Basin, as further described in "Acquisitions and Divestitures" within Item 1 of this Annual Report on Form 10-K.

Sales of minerals in place totaled 10.7 MMBOE during 2021 and were primarily attributable to the disposition of all of our interests in the producing assets and undeveloped acreage of our Redtail field located in the Denver-Julesburg Basin of Weld County, Colorado, as further described in "Acquisitions and Divestitures" within Item 1 of this Annual Report on Form 10-K.

In 2021, revisions to previous estimates increased proved developed and undeveloped reserves by a net amount of 73.8 MMBOE. Included in these revisions were (i) 70.1 MMBOE of upward adjustments resulting from higher crude oil, NGL and natural gas prices incorporated into our reserve estimates at December 31, 2021 as compared to December 31, 2020, (ii) 12.8 MMBOE of upward adjustments primarily attributable to reservoir and engineering analysis and well performance across our North Dakota and Montana assets, and (iii) 0.8 MMBOE of upward adjustments attributable to narrower differentials and stronger NGL yields. The above upward adjustments were partially offset by 9.9 MMBOE of downward adjustments due to increased operating expenses.

Proved undeveloped reserves. Our PUD reserves increased 23% or 11.8 MMBOE on a net basis from December 31, 2020 to December 31, 2021. The following table provides a reconciliation of our PUD reserves for the year ended December 31, 2021:

	Total (MBOE)
PUD balance—December 31, 2020	52,165
Converted to proved developed through drilling	(20,354)
Added from extensions and discoveries	18,709
Purchased	4,405
Revisions	9,077
PUD balance—December 31, 2021	64,002

Material changes in proved undeveloped reserves for the year ended December 31, 2021 included the following:

- *Converted to proved developed through drilling.* During 2021, we incurred $100 million in capital expenditures, or $4.94 per BOE, to drill and TIL 20.4 MMBOE of PUD reserves. These expenditures primarily consisted of completion costs to TIL wells we drilled in 2019 and 2020.

- *Added from extensions and discoveries.* We added 18.7 MMBOE of PUDs from extensions and discoveries during the year primarily due to successful drilling in the Williston Basin.

- *Purchased.* During 2021 we added total PUD volumes of 4.4 MMBOE primarily through two acquisitions in the Williston Basin, as further described in “Acquisitions and Divestitures” in Item 1 of this Annual Report on Form 10-K.

- *Revisions.* In 2021, revisions to previous estimates increased proved undeveloped reserves by a net amount of 9.1 MMBOE. Included in these revisions were (i) 7.2 MMBOE of upward adjustments from higher crude oil, NGL and natural gas prices incorporated into our estimates at December 31, 2021 as compared to December 31, 2020 and (ii) 1.9 MMBOE of upward adjustments attributable to well performance across our assets in North Dakota and Montana.

We have made an investment decision and adopted a development plan to drill all of our individual PUD locations within five years of the date such PUDs were added. Under our current 2022 development plan, we expect to convert approximately 24.6 MMBOE (or 38%) of our PUDs to proved developed reserves during the year.

Preparation of reserves estimates. We believe that we maintain adequate and effective internal controls over the reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information, which is updated annually, is assessed for validity when the reservoir engineers hold technical meetings with geoscientists, operations and land personnel to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from our accounting records, which are subject to our internal controls over financial reporting. Internal controls over financial reporting are assessed for effectiveness annually using the criteria set forth in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. All current financial data such as commodity prices, lease operating expenses, transportation, gathering, compression and other expenses, production taxes, abandonment costs and field commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. Our current ownership in mineral interests and well production data are also subject to the aforementioned internal controls over financial reporting, and they are incorporated into the reserve database as well and verified to ensure their accuracy and completeness. Once the reserve database has been entirely updated with current information, and all relevant technical support material has been assembled, our independent engineering firm Netherland, Sewell & Associates, Inc. (“NSAI”) meets with our technical personnel to review field performance and future development plans. Following this review, the reserve database and supporting data is furnished to NSAI so that they can prepare their independent reserve estimates and final report. Access to our reserve database is restricted to specific members of the reservoir engineering department.

The reserves estimates shown herein have been independently evaluated 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 are Mr. Richard B. Talley, Jr. and Mr. Edward C. Roy III. Mr. Talley, a Licensed Professional Engineer in the State of Texas (No. 102425) and in the State of Louisiana (No. 36998), has been practicing as a petroleum engineering consultant at NSAI since 2004 and has over 5 years of prior industry experience. He graduated from University of Oklahoma in 1998 with a Bachelor of Science degree in mechanical engineering and from Tulane University in 2001 with a Master of Business Administration degree. Mr. Roy, a Licensed Professional Geoscientist in the State of Texas, Geology (No. 2364), has been practicing as a petroleum geoscience consultant at NSAI since 2008 and has over 11 years of prior industry experience. He graduated from Texas Christian University in 1992 with a Bachelor of Science degree in geology and from Texas A&M University in 1998 with a Master of Science degree in geology. Both technical principals meet or exceed 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 are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Our Reserves and Reservoir Engineering Manager is responsible for overseeing the preparation of the reserves estimates under the supervision of the Chief Operating Officer, Charles Rimer. Our Reserves and Reservoir Engineering Manager has more than 11 years of broad reservoir engineering experience in the oil and gas industry, focused across conventional and unconventional evaluation and development projects, including corporate reserves estimations. He holds a Bachelor of Science degree in petroleum engineering from the Colorado School of Mines and is a member of the Society of Petroleum Engineers.

Acreage

The following table summarizes gross and net developed and undeveloped acreage by core area at December 31, 2021. Net acreage represents our percentage ownership of gross acreage. Acreage in which our interest is limited to royalty and overriding royalty interests has been excluded.

	Developed Acreage		Undeveloped Acreage (1)		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
North Dakota & Montana	710,466	464,129	20,601	15,538	731,067	479,667
Other (2)	88,433	53,988	25,151	6,247	113,584	60,235
	798,899	518,117	45,752	21,785	844,651	539,902

(1) Out of a total of approximately 45,800 gross (21,800 net) undeveloped acres as of December 31, 2021, the portion of our net undeveloped acreage that is subject to expiration over the next three years, if not successfully developed or renewed, is approximately 58% in 2022, 6% in 2023 and 5% in 2024. We have not assigned any proved undeveloped reserves to locations scheduled to be drilled after lease expiration.

(2) Other includes Arkansas, Colorado, Louisiana, Michigan, Mississippi, New Mexico, Oklahoma, Texas, Utah and Wyoming.

Production History

The following table presents historical information about our produced oil and gas volumes. On September 1, 2020 (the “Emergence Date”), we emerged from chapter 11 bankruptcy. The application of fresh start accounting resulted in a new basis of accounting and our becoming a new entity for financial reporting purposes. As a result, the consolidated financial statements after the Emergence Date are not comparable to the consolidated financial statements before that date and the historical financial statements on or before the Emergence Date are not a reliable indicator of our financial condition and results of operations for any period after our adoption of fresh start accounting. Refer to the “Fresh Start Accounting” footnote in the consolidated financial statements in Item 8 of this Annual Report on Form 10-K for more information. References to “Successor” refer to our financial position and results of operations after the Emergence Date. References to “Predecessor” refer to our financial position and results of operations on or before the Emergence Date. References to “2020 Successor Period” refer to the period from September 1, 2020 through December 31, 2020. References to “2020 Predecessor Period” refer to the period January 1, 2020 through August 31, 2020. Although GAAP requires that we report on our results for the 2020 Successor Period and the 2020 Predecessor Period separately, in certain circumstances management views our 2020 operating results by combining the results of the applicable Predecessor and Successor periods in order to provide the most meaningful comparisons to current and prior periods.

	Successor		Predecessor	Non-GAAP	Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Combined Year Ended December 31, 2020	Year Ended December 31, 2019
Total company production					
Oil (MMBbl)	19.3	6.8	15.3	22.1	29.8
NGL (MMBbl)	7.2	2.1	4.5	6.6	7.6
Natural gas (Bcf)	42.0	14.3	29.7	44.0	50.5
Total (MMBOE)	33.5	11.4	24.7	36.1	45.8
Daily average (MBOE/d)	91.9	93.0	101.4	98.6	125.5
Sanish field production [1]					
Oil (MMBbl)	5.8	1.9	4.2	6.1	5.8
NGL (MMBbl)	1.2	0.4	0.8	1.2	1.1
Natural gas (Bcf)	8.6	2.8	5.5	8.3	7.6
Total (MMBOE)	8.4	2.8	5.9	8.7	8.2
Average sales prices (before the effects of hedging)					
Oil (per Bbl)	$ 64.77	$ 37.05	$ 28.86	$ 31.40	$ 50.06
NGLs (per Bbl)	$ 22.53	$ 5.90	$ 4.45	$ 4.91	$ 6.76
Natural gas (per Mcf)	$ 2.34	$ 0.48	$ (0.06)	$ 0.11	$ 0.57
Average production costs (per BOE)					
Lease operating expenses	$ 7.23	$ 6.52	$ 6.40	$ 6.43	$ 7.17
Transportation, gathering, compression and other	$ 0.90	$ 0.71	$ 0.90	$ 0.84	$ 0.93

(1) The Sanish field was our only field that contained 15% or more of our total proved reserve volumes at the end of the years presented.

Productive Wells

The following table summarizes gross and net productive oil and natural gas wells by core area at December 31, 2021. A net well represents our percentage ownership of a gross well. Wells in which our interest is limited to royalty and overriding royalty interests are excluded.

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
North Dakota & Montana	3,394	1,527	-	-	3,394	1,527
Other [1]	1,256	350	70	40	1,326	390
Total	4,650	1,877	70	40	4,720	1,917

(1) Other primarily includes non-core oil and gas properties located in Colorado, New Mexico, Texas and Wyoming.

Oil and Gas Drilling Activity

We are engaged in drilling activities on properties presently owned, and we intend to drill or develop other properties acquired in the future. The following table sets forth our wells completed for the last three years. A dry well is an exploratory, development or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. A productive well is an exploratory, development or extension well that is not a dry well. The information below should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and quantities of reserves found.

	Gross Wells			Net Wells		
	Productive	Dry	Total	Productive	Dry	Total
2021						
Development	57	-	57	34.4	-	34.4
Exploratory	-	-	-	-	-	-
Total	57	-	57	34.4	-	34.4
2020						
Development	54	-	54	30.4	-	30.4
Exploratory	-	-	-	-	-	-
Total	54	-	54	30.4	-	30.4
2019						
Development	208	2	210	93.9	0.1	94.0
Exploratory	-	-	-	-	-	-
Total	208	2	210	93.9	0.1	94.0

As of December 31, 2021, we had two operated drilling rigs active on our properties. As of December 31, 2021, we had 50 gross (22.4 net) operated and non-operated wells in the process of drilling, completing or waiting on completion.

Hydraulic Fracturing

Hydraulic fracturing is a common practice in the oil and gas industry that is used to stimulate production of hydrocarbons from tight oil and gas formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. This process has typically been regulated by state oil and gas commissions. However, as described in more detail in "Business – Regulation – Environmental Regulations – Hydraulic Fracturing" in Item 1 of this Annual Report on Form 10-K, the EPA continues to consider the regulation of hydraulic fracturing, other federal agencies are examining hydraulic fracturing, and federal legislation is pending with respect to hydraulic fracturing. We have utilized hydraulic fracturing in the completion of our wells in our most active areas located in the states of North Dakota and Montana and we plan to continue to utilize this completion methodology.

Substantially all of our 64.0 MMBOE of proved undeveloped reserves are expected to be developed through the use of hydraulic fracture treatments.

We are not aware of any environmental incidents, citations or suits that have occurred during the last three years related to hydraulic fracturing operations involving oil and gas properties that we operate or in which we own a non-operated interest.

In order to minimize environmental impacts from hydraulic fracture treatments, we have taken the following steps:

- we follow fracturing and flowback procedures that comply with or exceed North Dakota Industrial Commission or other state requirements;
- we train all company and contract personnel who are responsible for well preparation, fracture stimulation and flowback on our procedures;
- we routinely run casing caliper logs and/or ultrasonic logs on intermediate casing, pressure test the casing, and match maximum fracturing pressure limitations with the condition of the casing;
- we construct berming around the outside portion of all our well locations which is in place prior to initiating fracturing operations;
- we run tie-back fracturing strings on wells that have casing wear or cement tops that necessitate additional protection to meet state requirements;
- we conduct annual emergency incident response drills in our active areas;
- we are a member of the Sakakawea Area Spill Response LLC ("SASR"), which is comprised of 17 oil and gas related companies operating in the Missouri River and Lake Sakakawea regions of North Dakota. Members agree to share spill response resources and maintain SASR-owned water response equipment that can be accessed quickly in the early stages of a spill; and

- we participate in a voluntary baseline groundwater sampling program that is executed prior to drilling each well, even when no regulatory requirement exists, to ensure our operations do not negatively impact local groundwater resources. This program involves a thorough evaluation of potential groundwater sources within a half-mile radius, sampling prior to setting the well conductor and follow-up samples within one year of well completion.

While we do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations, we do have general liability and excess liability insurance policies that we believe would cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies.

Delivery Commitments

Our production sales agreements contain customary terms and conditions for the oil and natural gas industry, generally provide for sales based on prevailing market prices in the area, and generally have terms of one year or less.

We have one physical delivery contract effective as of December 31, 2021 which is tied to oil production at our Sanish field in Mountrail County, North Dakota for a term ending May 31, 2024. Under the terms of the contract, we are required to deliver 15,000 barrels of oil per day during the delivery term. If we fail to deliver the committed volumes we will be required to pay a deficiency payment of approximately $7.00 per undelivered Bbl, subject to upward adjustment, over the duration of the contract. We believe that our production and reserves are sufficient to fulfill the delivery commitment at our Sanish field, and we therefore expect to avoid any payments for deficiencies under this contract. However, a default on this contract could have a material impact on our business, financial condition, results of operations and cash flows.

We have another physical delivery contract effective as of December 31, 2021 which is tied to oil production in North Dakota and Montana for a term ending June 30, 2024. Under the terms of the contract, we are required to deliver 5,000 barrels of oil per day during the delivery term. If we fail to deliver any of the committed volumes during the term of the contract, we will be in immediate default under the contract and will be required to pay liquidated damages for the remaining term of the contract. We believe that our production and reserves are sufficient to fulfill this delivery commitment, and we therefore expect to avoid any payments for deficiencies under this contract. However, a default on this contract could have a material impact on our business, financial condition, results of operations and cash flows.

The following table summarizes these commitments as of December 31, 2021:

Period	Contracted Crude Oil Volumes (Bbl)	As a Percentage of Total 2021 Production
Jan - Dec 2022	7,300,000	22%
Jan - Dec 2023	7,300,000	22%
Jan - Jun 2024	3,190,000	11%

We previously committed to deliver oil from our Redtail field in Weld County, Colorado under two physical delivery contracts, one of which expired in February 2018 and the other in April 2020. We were unable to deliver the committed volumes under these contracts and thus incurred deficiency fees of $24 million and $64 million during the 2020 Predecessor Period and the year ended December 31, 2019, respectively.

Item 3. <u>Legal Proceedings</u>

The information contained in the “Commitments and Contingencies” footnote under the headings “Chapter 11 Cases” and “Litigation” in the notes to the consolidated financial statements in Item 8 of this Annual Report on Form 10-K is incorporated herein by reference.

Item 4. <u>Mine Safety Disclosures</u>

Not applicable.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

The following table sets forth certain information, as of February 17, 2022, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
Lynn A. Peterson	68	President and Chief Executive Officer
Charles J. Rimer	64	Executive Vice President, Operations and Chief Operating Officer
James P. Henderson	56	Executive Vice President, Finance and Chief Financial Officer
Sirikka R. Lohoefener	43	Vice President, Accounting and Controller
M. Scott Regan	51	Vice President, Legal, General Counsel and Secretary

The following biographies describe the business experience of our executive officers:

Lynn A. Peterson joined us in September 2020 as President and Chief Executive Officer. Mr. Peterson has 41 years of experience in the oil and gas industry. Prior to joining Whiting, Mr. Peterson was the Chairman of the Board, Chief Executive Officer and President of SRC Energy from 2015 until the closing of its merger with PDC Energy in January 2020. From January 2020 until September 2020 he was a private investor. He was a co-founder of Kodiak Oil & Gas Corporation ("Kodiak") and served Kodiak as a director (2001-2014) and as its President and Chief Executive Officer (2002-2014) and Chairman of the Board (2011-2014) until its acquisition by Whiting in 2014. He also previously served as a director at Whiting from December 2014 to June 2015. Mr. Peterson holds a Bachelor of Science degree in accounting from the University of Northern Colorado.

Charles J. Rimer joined us in November 2018 as Chief Operating Officer. Mr. Rimer has 39 years of experience in the industry. Prior to joining Whiting, he was Senior Vice President, U.S. Onshore at Noble Energy, Inc. from 2017 to November 2018. Additionally, he held various management and technical positions during his 16 years at Noble Energy, Inc. including Senior Vice President, Global Services; Senior Vice President, Global EHSR and Operations Services; Vice President of Operations Services; among others. He also held various management and technical positions at Aspect Resources, Vastar Resources and ARCO Oil & Gas Company where he began his career in 1983. Mr. Rimer holds a Bachelor of Arts degree in business from Furman University and a Bachelor of Science degree in petroleum engineering from the University of Texas.

James P. Henderson joined us in September 2020 as Executive Vice President Finance and Chief Financial Officer. Mr. Henderson has 31 years of oil and gas experience. Prior to joining Whiting, Mr. Henderson served as Chief Financial Officer of SRC Energy from 2015 until the closing of its merger with PDC Energy in January 2020. From January 2020 until September 2020 he was a private investor. He also served as Chief Financial Officer of Kodiak until its acquisition by Whiting in 2014. Prior to joining Kodiak, Mr. Henderson held various positions at Aspect Energy, Anadarko Petroleum, Western Gas Resources, Apache Corporation and Pennzoil Company. He holds a Bachelor of Business Administration degree in accounting from Texas Tech University and a Master of Business Administration degree in finance from Regis University.

Sirikka R. Lohoefener joined us in June 2006 as a Senior Financial Accountant, became Financial Reporting Manager in January 2011 and Controller in March 2015. She was appointed Controller and Treasurer in March 2017, Vice President, Controller and Treasurer in December 2018 and Vice President, Accounting and Controller in October 2019 and serves as the Company's designated principal accounting officer. Prior to joining Whiting, Ms. Lohoefener spent five years with Wagner, Burke & Barnes, LLP, a public accounting firm previously based in Golden, Colorado. She holds a Master of Accountancy degree from the University of Missouri and is a Certified Public Accountant.

M. Scott Regan joined us in November 2015 as Deputy General Counsel and was appointed Vice President, Legal, General Counsel and Secretary in November 2020. He has 18 years of experience in the oil and gas industry. Prior to joining Whiting, Mr. Regan served in various positions in the legal department of Ovintiv, where he most recently served as Vice President, Legal, Western and Southern Operations. Mr. Regan began his legal career in 1996 with the law firm of Crowley, Haughey, Hanson, Tool & Dietrich (now Crowley Fleck) in Helena, Montana and joined Holland & Hart in Denver, Colorado in 1998. Mr. Regan has a Bachelor of Arts degree in history from Montana State University and a Juris Doctor degree from the University of Montana School of Law.

Executive officers are elected by, and serve at the discretion of, the Board. There are no family relationships between any of our directors or executive officers.

PART II

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

Whiting Petroleum Corporation’s common stock is traded on the New York Stock Exchange under the symbol “WLL”. On February 17, 2022, there were 561 holders of record of our common stock.

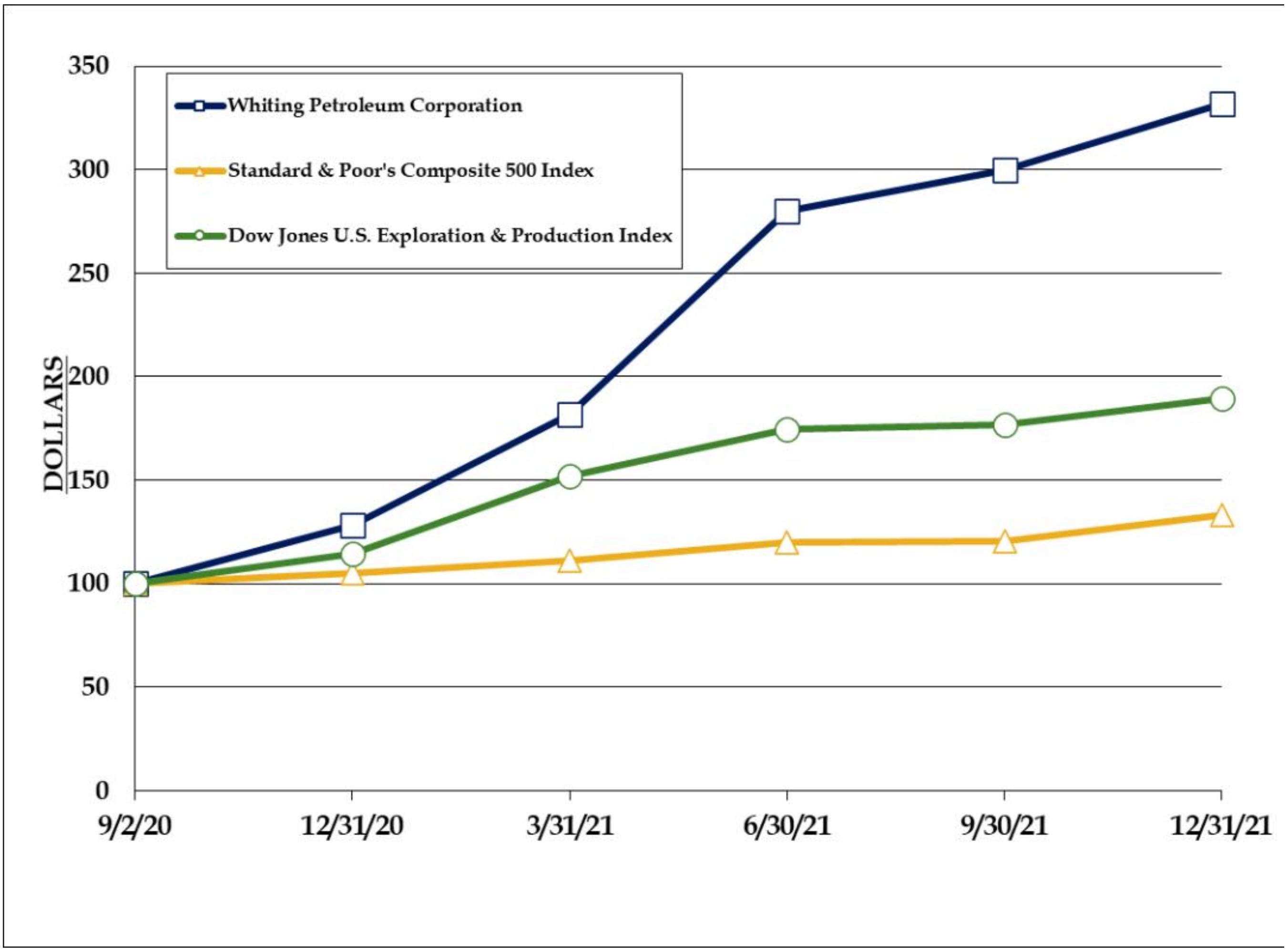
On September 1, 2020, upon emergence from chapter 11 bankruptcy, all existing shares of the Predecessor Company’s (as defined in Item 8 of this Annual Report on Form 10-K) common stock were cancelled and the reorganized Whiting issued 38,051,125 shares of new common stock as well as 4,837,821 Series A Warrants and 2,418,910 Series B Warrants to purchase shares of the reorganized Whiting’s common stock. For more information regarding our emergence from chapter 11 bankruptcy refer to the “Chapter 11 Emergence” footnote in the notes to the consolidated financial statements in Item 8 of this Annual Report on Form 10-K.

We declared a dividend of $0.25 per share of common stock for the first quarter of 2022, payable as of March 15, 2022 to shareholders of record as of February 21, 2022. Previously, we had not paid any cash dividends on our common stock since we were incorporated in July 2003. Our future dividend policy is within the discretion of our Board and will depend upon various factors, including our financial position, cash flows, results of operations, capital requirements and investment opportunities.

Information relating to compensation plans under which our equity securities are authorized for issuance is set forth in Part III, Item 12 of this Annual Report on Form 10-K.

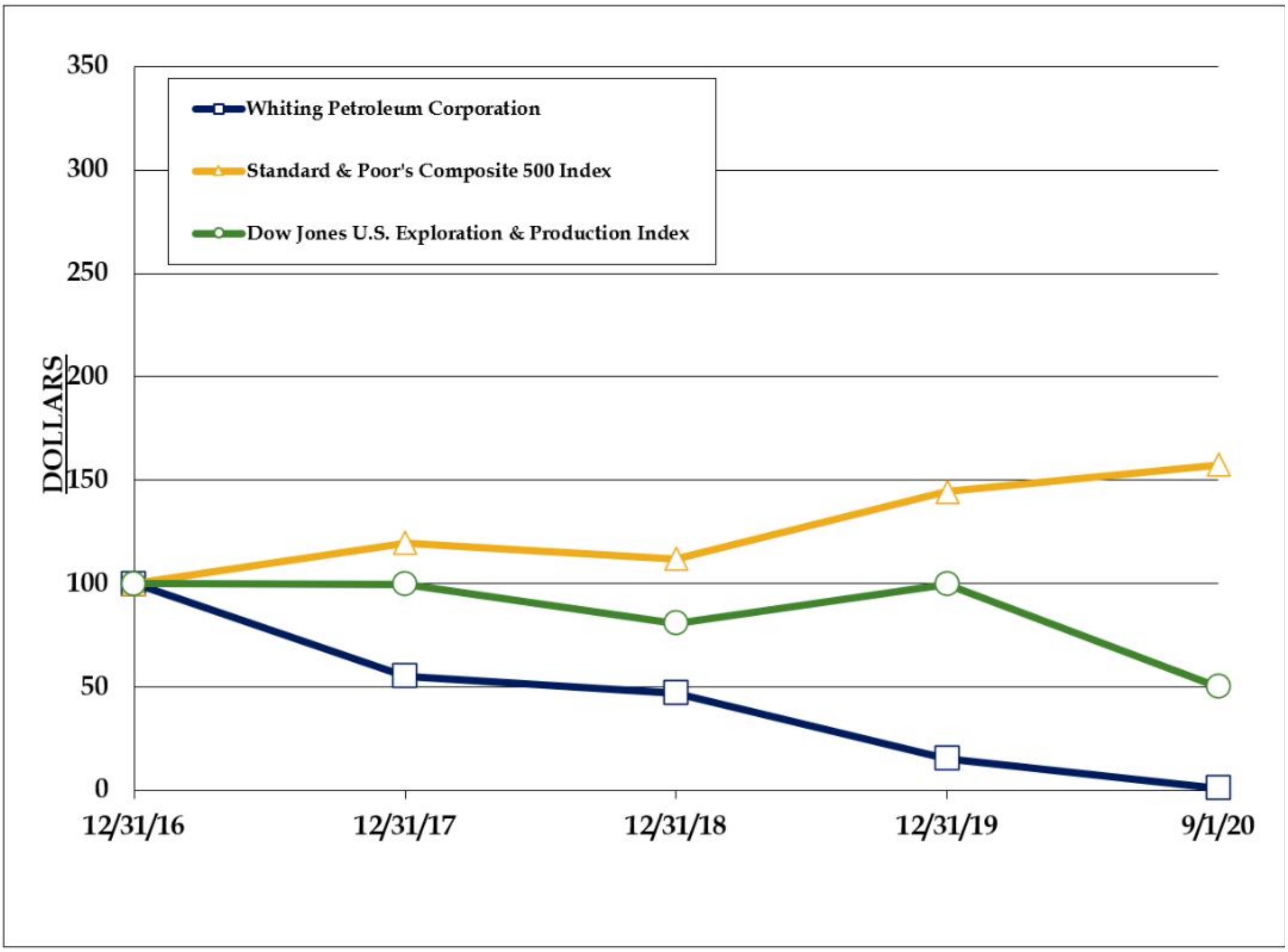
The following information in this Item 5 of this Annual Report on Form 10-K is not deemed to be “soliciting material” or to be “filed” with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934 or to the liabilities of Section 18 of the Securities Exchange Act of 1934, and will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent we specifically incorporate it by reference into such a filing.

The following graph compares on a cumulative basis changes since September 2, 2020 (first full trading day post-bankruptcy) in (a) the total stockholder return on our common stock with (b) the total return on the Standard & Poor's Composite 500 Index and (c) the total return on the Dow Jones U.S. Exploration & Production Index. Such changes have been measured by dividing (a) the sum of (i) the cumulative amount of dividends for the measurement period, assuming dividend reinvestment, and (ii) the difference between the price per share at the end of and the beginning of the measurement period, by (b) the price per share at the beginning of the measurement period. The graph assumes $100 was invested on September 2, 2020 at market closing in our common stock, the Standard & Poor's Composite 500 Index and the Dow Jones U.S. Exploration & Production Index, respectively.



	9/2/2020	12/31/2020	3/31/2021	6/30/2021	9/30/2021	12/31/2021
Whiting Petroleum Corporation	$ 100	$ 128	$ 182	$ 280	$ 300	$ 332
Standard & Poor's Composite 500 Index	100	105	111	120	120	133
Dow Jones U.S. Exploration & Production Index	100	114	152	175	177	189

The following graph compares on a cumulative basis changes from December 31, 2016 through September 1, 2020 (last full trading day pre-bankruptcy) in (a) the total stockholder return on our common stock with (b) the total return on the Standard & Poor's Composite 500 Index and (c) the total return on the Dow Jones U.S. Exploration & Production Index. Such changes have been measured by dividing (a) the sum of (i) the cumulative amount of dividends for the measurement period, assuming dividend reinvestment, and (ii) the difference between the price per share at the end of and the beginning of the measurement period, by (b) the price per share at the beginning of the measurement period. The graph assumes $100 was invested on December 31, 2016 at market closing in our common stock, the Standard & Poor's Composite 500 Index and the Dow Jones U.S. Exploration & Production Index, respectively.



	12/31/2016	12/31/2017	12/31/2018	12/31/2019	9/1/2020
Whiting Petroleum Corporation	$ 100	$ 55	$ 47	$ 15	$ 1
Standard & Poor's Composite 500 Index	100	119	112	144	158
Dow Jones U.S. Exploration & Production Index	100	100	81	100	50

Item 6. Reserved

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

Unless the context otherwise requires, the terms "Whiting," "we," "us," "our" or "ours" when used in this Item refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries, Whiting Oil and Gas Corporation ("Whiting Oil and Gas" or "WOG"), Whiting US Holding Company, Whiting Canadian Holding Company ULC, Whiting Resources LLC ("WRC," formerly Whiting Resources Corporation) and Whiting Programs, Inc. In September 2020, Whiting US Holding Company merged with and into WOG with WOG surviving, and WRC transferred all of its operating assets to WOG. In November 2020, WRC, over a series of steps, was amalgamated with Whiting Canadian Holding Company ULC and subsequently dissolved. When the context requires, we refer to these entities separately. This document contains forward-looking statements, which give our current expectations or forecasts of future events. Please refer to "Forward-Looking Statements" at the end of this Item for an explanation of these types of statements.

Overview

We are an independent oil and gas company engaged in development, production and acquisition activities primarily in the Rocky Mountains region of the United States where we are focused on developing our large resource play in the Williston Basin of North Dakota and Montana. Since our inception, we have built a strong asset base through a combination of property acquisitions, development of proved reserves and exploration activities. We are currently focusing our capital programs on drilling and workover opportunities that we believe provide attractive well-level returns in order to maintain consistent production levels and generate free cash flow. In addition, we are selectively pursuing acquisitions that complement our existing core properties. During 2021, we focused on high-return projects in our asset portfolio that generated significant cash flow from operations. We continually evaluate our property portfolio and sell properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own. Refer to "Recent Developments" below for more information on our recent acquisition and divestiture activity.

We are committed to developing the energy resources the world needs in a safe and responsible way that allows us to protect our employees, our contractors, our vendors, the public and the environment while also meeting or exceeding regulatory requirements. We continually evolve our practices to better protect wildlife habitats and communities, to reduce freshwater use in our development process, to identify and reduce methane emissions of our operations, to encourage waste reduction programs and to promote worker safety. Additionally, we are committed to transparency in reporting our environmental, social and governance performance and to monitoring such performance through various measures, some of which are tied to our short-term incentive program for all employees. Refer to our Sustainability Report published on our website for sustainability performance highlights and additional information. Information contained in our Sustainability Report is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K. Concurrently, our oil and gas development and production operations are subject to stringent environmental regulations governing the release of certain materials into the environment which often require costly compliance measures that carry substantial penalties for noncompliance. However, we have not incurred any material penalties historically. Refer to "Government Regulation" in Item 1 of this Annual Report on Form 10-K for more information.

Our revenue, profitability, cash flows and future growth rate depend on many factors which are beyond our control, such as oil and gas prices, economic, political and regulatory developments, the financial condition of our industry partners, competition from other sources of energy, cost pressures as a result of inflation and the other items discussed under the caption "Risk Factors" in Item 1A of this Annual Report on Form 10-K. Oil and gas prices historically have been volatile and may fluctuate widely in the future. The following table highlights the quarterly average NYMEX price trends for crude oil and natural gas prices since the first quarter of 2019:

	2019				2020				2021			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Crude oil	$54.90	$59.83	$56.45	$56.96	$46.08	$27.85	$40.94	$42.67	$57.80	$66.06	$70.55	$77.17
Natural gas	$ 3.00	$ 2.58	$ 2.29	$ 2.44	$ 1.88	$ 1.66	$ 1.89	$ 2.51	$ 2.56	$ 2.74	$ 3.95	$ 5.13

Oil prices improved during 2021 compared to the lows experienced during 2020, when prices were depressed primarily due to the economic effects of the coronavirus pandemic on the demand for oil and natural gas and uncertainty around output restraints on oil production agreed upon by the Organization of Petroleum Exporting Countries ("OPEC") and other oil exporting nations. While oil, NGL and natural gas prices have recovered significantly, uncertainties related to the demand for oil and natural gas products remain as the pandemic continues to impact the world economy and OPEC continues to debate appropriate production levels to balance the market. Lower oil, NGL and natural gas prices decrease our revenues and reduce the amount of oil and natural gas that we can produce economically, which decreases our oil and gas reserve quantities. Substantial and extended declines in oil, NGL and natural gas prices have resulted, and may result, in impairments of our proved oil and gas properties or undeveloped acreage (such as the impairments discussed below under "Results of Operations") and may materially and adversely affect our future business, financial condition, cash

flows, results of operations, liquidity or ability to fund planned capital expenditures. In addition, lower commodity prices may result in a reduction of the borrowing base under our Credit Agreement, which is determined at the discretion of our lenders and is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of the debt outstanding under our Credit Agreement. Alternatively, higher oil prices may result in significant mark-to-market losses being incurred on our commodity-based derivatives (such as the net derivative losses discussed below under "Results of Operations").

For a discussion of material changes to our proved reserves from December 31, 2020 to December 31, 2021 and our ability to convert PUDs to proved developed reserves, refer to "Reserves" in Item 2 of this Annual Report on Form 10-K. Additionally, for a discussion relating to the minimum remaining terms of our leases, refer to "Acreage" in Item 2 of this Annual Report on Form 10-K.

Recent Developments

Return of Capital. In February 2022, we announced an initial regular dividend payment of $0.25 per share which will begin in the first quarter of 2022. Our Board and management are committed to returning capital in line with our industry peers and we will continue to evaluate all forms of capital returns, including buying back outstanding shares and paying variable dividends.

Williston Basin Acquisitions. On September 14, 2021, we completed the acquisition of interests in oil and gas properties located in Mountrail County, North Dakota for an aggregate purchase price of $271 million (before closing adjustments). This transaction was funded primarily with borrowings under our Credit Agreement, which have subsequently been repaid.

On December 16, 2021, we completed the acquisition of additional interests in oil and gas properties located in Mountrail County, North Dakota for an aggregate purchase price of $32 million (before closing adjustments). This transaction was funded with cash on hand and borrowings under our Credit Agreement, which have subsequently been repaid.

On February 1, 2022, we entered into a purchase and sale agreement to acquire additional interests in oil and gas properties located in Mountrail County, North Dakota for an aggregate purchase price of $240 million (before closing adjustments). We expect this transaction to close in March 2022. We intend to finance this acquisition with cash on hand and borrowings under our Credit Agreement.

On a combined basis, our recent Williston Basin acquisitions included interests in 76 new gross producing oil and gas wells and increased interests in 527 existing gross producing wells. Overall, the acquisitions effectively added 136.2 net producing wells and included approximately 23,300 net undeveloped acres.

Denver-Julesburg Basin Divestiture. On September 23, 2021, we completed the divestiture of all of our interests in producing assets and undeveloped acreage, including the associated midstream assets, of our Redtail field located in the Denver-Julesburg Basin of Weld County, Colorado for aggregate sales proceeds of $171 million (before closing adjustments). The divestiture remains subject to a final settlement between Whiting and the buyer of the properties. The production from the divested properties (which was approximately 51% oil) represented approximately 8% of our average total production as of the divestiture date. We used the net proceeds from the sale to repay a portion of the borrowings outstanding under our Credit Agreement.

Chapter 11 Emergence and Fresh Start Accounting. On April 1, 2020 (the "Petition Date"), Whiting and certain of its subsidiaries (the "Debtors") commenced voluntary cases (the "Chapter 11 Cases") under chapter 11 of the Bankruptcy Code. On June 30, 2020, the Debtors filed the Joint Chapter 11 Plan of Reorganization of Whiting Petroleum Corporation and its Debtor affiliates (as amended, modified and supplemented, the "Plan"). On August 14, 2020, the Bankruptcy Court confirmed the Plan. On September 1, 2020 (the "Emergence Date"), the Debtors satisfied all conditions required for Plan effectiveness and emerged from the Chapter 11 Cases.

Beginning on the Emergence Date, we applied fresh start accounting, which resulted in a new basis of accounting and we became a new entity for financial reporting purposes. As a result of the application of fresh start accounting and the effects of the implementation of the Plan, the consolidated financial statements after September 1, 2020 are not comparable with the consolidated financial statements on or prior to that date and the historical financial statements on or before the Emergence Date are not a reliable indicator of our financial condition and results of operations for any period after the adoption of fresh start accounting. References to "Successor" refer to Whiting and its financial position and results of operations after the Emergence Date. References to "Predecessor" refer to Whiting and its financial position and results of operations on or before the Emergence Date. References to "2020 Successor Period" relate to the period of September 1, 2020 through December 31, 2020. References to "2020 Predecessor Period" relate to the period of January 1, 2020 through August 31, 2020. Although GAAP requires that we report on our results for the 2020 Successor Period and the 2020 Predecessor Period separately, in certain circumstances management views our combined Predecessor and Successor operating results for the year ended December 31, 2020 as the most meaningful comparisons to current and prior periods. Accordingly, references to "2020 Combined YTD Period" refer to the year ended December 31, 2020.

Settlement of Bankruptcy Claims. Prior to the Chapter 11 Cases, WOG was party to various executory contracts with BNN Western, LLC, subsequently renamed Tallgrass Water Western, LLC ("Tallgrass"), including a Produced Water Gathering and Disposal Agreement (the "PWA"). In January 2021, WOG and Tallgrass entered into a settlement agreement to resolve all of the related claims before the Bankruptcy Court relating to such executory contracts, terminated the PWA and entered into a new Water Transport, Gathering and Disposal Agreement. In accordance with the settlement agreement, we made a $2 million cash payment and issued 948,897 shares of the Successor's common stock pursuant to the confirmed Plan to a Tallgrass entity in February 2021.

2021 Highlights and Future Considerations

Operational Highlights

North Dakota and Montana – Williston Basin

Our properties in the Williston Basin of North Dakota and Montana target the Bakken and Three Forks formations. Net production from North Dakota and Montana averaged 91.6 MBOE/d for the fourth quarter of 2021, representing an 8% increase from the third quarter of 2021. Across our acreage in the Williston Basin, we have implemented completion designs specifically tailored to unique reservoir conditions to increase well performance while reducing cost. We continued to focus on reducing time-on-location and total well cost while maximizing our lateral footage through drilling best practices including utilizing top tier drilling rigs, advanced downhole motor and drill bit technology and our custom drilling fluid system.

During the year ended December 31, 2021 and the first part of 2022, we completed several acquisitions of additional oil and gas properties in the Williston Basin. Refer to "Recent Developments" above for additional details.

During the majority of 2021, we had one active completion crew in the Williston Basin. In addition, we resumed drilling in the area in February with one rig and added a second rig at the end of September. During the fourth quarter of 2021, we drilled 17 gross (10.4 net) operated wells and TIL 16 gross (12.0 net) operated wells in this area. As of December 31, 2021, we have 34 gross (20.2 net) operated drilled uncompleted wells. Under our current 2022 capital program, we expect to TIL approximately 68 gross (43.4 net) operated wells in this area during the year.

Other Non-Core Properties

Whiting USA Trust II. On December 31, 2021, the net profits interest ("NPI") conveyed to Whiting USA Trust II ("Trust II") on March 28, 2012 terminated. Upon termination, the NPI in the underlying properties, which received 90% of the net cash proceeds from the sale of oil and natural gas production from the underlying properties prior to its termination, reverted to Whiting. As of December 31, 2021, the NPI included interests in 1,305 gross (364.4 net) producing wells. The incremental production from the underlying properties that reverted to Whiting upon termination was approximately 2.0 MBOE/d based on production during the fourth quarter of 2021. The incremental LOE expense that reverted to Whiting upon termination was approximately $2 million. The asset retirement obligations for these properties were not conveyed to Trust II and have therefore been included in our consolidated financial statements for all periods presented. Additionally, the reserves disclosed in this Annual Report on Form 10-K contemplate the reversion of the NPI on December 31, 2021.

Financing Highlights

On the Emergence Date, in connection with our emergence from the Chapter 11 Cases, we repaid all outstanding borrowings and accrued interest on the Predecessor's credit agreement (the "Predecessor Credit Agreement") and entered into the Credit Agreement with a syndicate of banks. In September 2021, the borrowing base under the Credit Agreement of $750 million was reaffirmed in connection with our semi-annual borrowing base redetermination. On September 15, 2021, we amended the Credit Agreement to reduce the amount of future production we are required to hedge. In accordance with the amendment, we are now only required to hedge 50% of our projected production for any succeeding twelve months, as compared to 65% prior to the amendment. Additionally, as long as we maintain a net leverage ratio of less than 1.0 to 1.0, we are no longer required to hedge any production for a second succeeding twelve months, compared to a 35% requirement prior to the amendment. Refer to the "Long-Term Debt" footnote in the notes to the consolidated financial statements for more information.

2022 Exploration and Development Budget

Our 2022 exploration and development ("E&D") budget is a range of $360 million to $400 million, which we expect to fund with net cash provided by our operating activities and cash on hand, and represents an increase from the $247 million incurred on E&D expenditures during 2021. This increase in spending is primarily attributable to increased working interests related to wells we plan to drill on the acreage acquired through our recent Williston Basin acquisitions as further described in "Recent Developments" above, fewer drilled uncompleted wells as of the end of 2021 as compared to the prior year and inflationary cost pressures on services and materials. The 2022 budget reinvests approximately 40% of our expected EBITDA for the year, which we expect to allow us to maintain our recently announced dividend and continue to increase our return of capital. We continue to maintain our commitment to keep our capital spending within cash flows generated from operations and strict adherence to economic full cycle well returns. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we would generate more or less free cash flow than we currently anticipate and may adjust our E&D budget or adjust borrowings outstanding under the Credit Agreement. We believe our 2022 E&D plan provides the opportunity for the highest return and most efficient use of our capital on our existing development opportunities.

Dakota Access Pipeline

On March 25, 2020, the U.S. District Court for D.C. ("D.C. District Court") found that the U.S. Army Corps of Engineers ("Army Corps") had violated the National Environmental Policy Act when it granted an easement relating to a portion of the Dakota Access Pipeline ("DAPL") because it had failed to prepare an environmental impact statement ("EIS"). As a result, in an order issued July 6, 2020, the D.C. District Court vacated the easement and directed that the DAPL be shut down and emptied of oil by August 5, 2020. After issuing a stay of the order to shut down the pipeline on August 5, 2020, the U.S. Court of Appeals for the D.C. Circuit ("D.C. Appellate Court"), on January 26, 2021, affirmed the D.C. District Court's decision to vacate the easement and concluded that the D.C. District Court must further consider whether shut down of the DAPL is an appropriate remedy while the Army Corps develops an EIS. On May 21, 2021, the D.C. District Court ruled that it would not issue an injunction requiring a shutdown of the DAPL and that the DAPL could continue to operate while the Army Corps prepares an EIS. The D.C. District Court further ruled on June 22, 2021 that the litigation be dismissed and that the plaintiffs could renew their challenge to DAPL upon the Army Corps' issuance of an EIS. Barring different discretionary action by the Army Corps, these rulings allow the DAPL's continued operation unless and until new challenges are made and succeed following issuance of the EIS, which the Army Corps anticipates issuing in the fall of 2022. On September 20, 2021, the DAPL's owner filed a petition with the U.S. Supreme Court seeking review of the lower courts' decisions requiring a new EIS and permit, and the plaintiff tribes and Army Corps filed briefs opposing such review. However, the U.S. Supreme Court declined to accept the case for review. The potential disruption of transportation as a result of the DAPL being shut down or the anticipation of the DAPL being shut down could negatively impact our ability to achieve the most favorable prices for our crude oil production, which could have an adverse effect on our business, financial condition, results of operations and cash flows. To help mitigate the potential impact of an unfavorable outcome, we have coordinated with our midstream partners and downstream markets to source transportation alternatives.

Results of Operations

We cannot adequately benchmark certain operating results of the 2020 Successor Period against any of the previous periods reported in our consolidated financial statements without combining that period with the 2020 Predecessor Period, and we do not believe that reviewing the results of this period in isolation would be useful in identifying trends in or reaching conclusions regarding our overall operating performance. Management believes that our key performance metrics such as sales, production, lease operating expenses and general and administrative expenses for the 2020 Successor Period when combined with the 2020 Predecessor Period provide more meaningful comparisons to current and prior periods and are more useful in identifying current business trends. Accordingly, in addition to presenting our results of operations as reported in our consolidated financial statements in accordance with GAAP, in certain circumstances the discussion in "Results of Operations" below utilizes the combined results for the year ended December 31, 2020.

	Successor		Predecessor	Non-GAAP
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Combined Year Ended December 31, 2020
Net production				
Oil (MMBbl)	19.3	6.8	15.3	22.1
NGLs (MMBbl)	7.2	2.1	4.5	6.6
Natural gas (Bcf)	42.0	14.3	29.7	44.0
Total production (MMBOE)	33.5	11.4	24.7	36.1
Net sales (in millions) (1)				
Oil	$ 1,251.0	$ 254.1	$ 440.8	$ 694.9
NGLs	162.6	12.4	20.1	32.5
Natural gas	98.2	6.9	(1.9)	5.0
Total oil, NGL and natural gas sales	$ 1,511.8	$ 273.4	$ 459.0	$ 732.4
Average sales prices				
Oil (per Bbl) (1)	$ 64.77	$ 37.05	$ 28.86	$ 31.40
Effect of oil hedges on average price (per Bbl)	(14.70)	(0.34)	3.00	1.96
Oil after the effect of hedging (per Bbl)	$ 50.07	$ 36.71	$ 31.86	$ 33.36
Weighted average NYMEX price (per Bbl) (2)	$ 67.86	$ 41.84	$ 38.23	$ 39.35
NGLs (per Bbl) (1)	$ 22.53	$ 5.90	$ 4.45	$ 4.91
Effect of NGL hedges on average price (per Bbl)	(1.19)	-	-	-
NGLs after the effect of hedging (per Bbl)	$ 21.34	$ 5.90	$ 4.45	$ 4.91
Natural gas (per Mcf) (1)	$ 2.34	$ 0.48	$ (0.06)	$ 0.11
Effect of natural gas hedges on average price (per Mcf)	(0.74)	(0.11)	(0.01)	(0.04)
Natural gas after the effect of hedging (per Mcf)	$ 1.60	$ 0.37	$ (0.07)	$ 0.07
Weighted average NYMEX price (per MMBtu) (2)	$ 3.59	$ 2.44	$ 1.76	$ 1.98
Costs and expenses (per BOE)				
Lease operating expenses	$ 7.23	$ 6.52	$ 6.40	$ 6.43
Transportation, gathering, compression and other	$ 0.90	$ 0.71	$ 0.90	$ 0.84
Production and ad valorem taxes	$ 3.29	$ 2.13	$ 1.67	$ 1.81
Depreciation, depletion and amortization	$ 6.16	$ 6.83	$ 13.69	$ 11.53
General and administrative	$ 1.48	$ 1.91	$ 3.71	$ 3.15

(1) Before consideration of hedging transactions.

(2) Average NYMEX pricing weighted for monthly production volumes.

2021 Compared to 2020 Successor Period and 2020 Predecessor Period or 2020 Combined YTD Period

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $779 million to $1.5 billion when comparing 2021 to the 2020 Combined YTD Period. Changes in sales revenue between periods are due to changes in production sold and changes in average commodity prices realized (excluding the impacts of hedging). When comparing 2021 to the 2020 Combined YTD Period, increases in commodity prices realized between periods accounted for an $865 million increase in revenue, which was partially offset by a decrease in total production between periods that accounted for an $86 million decrease in revenue.

Our oil and gas volumes decreased by 13% and 5%, respectively, while our NGL volumes increased by 9% between periods. The volume decreases between periods were primarily driven by normal field production decline and reduced development activity in 2020 as a result of sustained lower commodity prices and our bankruptcy filing, both of which negatively impacted production during 2021. The decline in production resulting from lower activity was partially offset by production from new wells drilled and completed in the Williston Basin during 2021 as well as higher NGL yields.

Our average price for oil, NGLs and natural gas (before the effects of hedging) increased 106%, 359% and 2,027%, respectively, between periods. Our average realized price for oil, NGLs and natural gas primarily increased as a result of favorable movements in benchmark indices between periods. Our oil average realized price differentials to NYMEX improved between periods as a result of decreased basin-wide utilization of pipeline capacity and lower firm transportation costs during 2021, and our natural gas average realized price differentials to NYMEX also improved significantly as a result of stronger regional pricing in the Williston Basin during 2021. During the 2020 Combined YTD Period, our average sales price realized for NGLs and natural gas was negatively impacted by rising market differentials as compared to market indices as well as high fixed third-party costs for transportation, gathering and compression services. These third-party costs sometimes exceeded the ultimate price we received for our natural gas and accordingly resulted in negative gas revenues during the 2020 Predecessor Period. While these negative gas prices adversely affected our total revenues, we continued to produce our wells in order to sell the associated oil and NGLs from these wells and to meet lease and regulatory requirements.

Lease Operating Expenses. Our lease operating expenses (“LOE”) during 2021 were $242 million, a $10 million increase over the 2020 Combined YTD Period. This increase was primarily due to a $16 million increase in well workover costs and a $7 million increase in the cost of oil field goods and services due to increased completion activity, partially offset by a $9 million decrease in saltwater disposal costs due to lower produced volumes between periods and a $5 million decrease due to increased utilization of company-owned equipment.

Our lease operating expenses on a BOE basis increased when comparing 2021 to the 2020 Combined YTD Period. LOE per BOE amounted to $7.23 during 2021, which represents an increase of $0.80 per BOE (or 12%) from the 2020 Combined YTD Period. This increase was mainly due to lower overall production volumes between periods and the overall increase in LOE discussed above.

Transportation, Gathering, Compression and Other. Our transportation, gathering, compression and other (“TGC”) expenses during 2021 were $30 million, which was consistent with the 2020 Combined YTD Period.

TGC per BOE, however, increased when comparing 2021 to the 2020 Combined YTD Period. TGC per BOE amounted to $0.90 per BOE during 2021, which represents an increase of $0.06 per BOE (or 7%) from the 2020 Combined YTD Period. This increase was mainly due to the transportation of certain oil volumes to additional delivery points during the second half of 2021, partially offset by decreased rates negotiated with midstream partners as a result of the Chapter 11 Cases.

Production and Ad Valorem Taxes. Our production and ad valorem taxes during 2021 were $110 million, a $45 million increase over the 2020 Combined YTD Period, which was primarily due to higher sales revenue between periods. Our production taxes, however, are generally calculated as a percentage of net oil, NGL and natural gas sales revenue before the effects of hedging, and this percentage on a company-wide basis was 7.0% and 8.5% for 2021 and the 2020 Combined YTD Period, respectively. Our production tax rate for 2021 was lower than the rate for the 2020 Combined YTD Period as certain production taxes levied on unprocessed gas are volume-based and did not increase with the increase in realized prices. Additionally, we recognized Colorado severance tax refunds during 2021.

Depreciation, Depletion and Amortization. The components of our depletion, depreciation and amortization ("DD&A") expense were as follows (in thousands):

	Successor		Predecessor	Non-GAAP
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Combined Year Ended December 31, 2020
Depletion	$ 193,529	$ 71,901	$ 327,227	$ 399,128
Accretion of asset retirement obligations	8,237	3,801	8,200	12,001
Depreciation	4,709	1,800	3,330	5,130
Total	$ 206,475	$ 77,502	$ 338,757	$ 416,259

DD&A decreased between 2021 and the 2020 Combined YTD Period primarily due to $206 million in lower depletion expense related to a lower depletion rate between periods. On a BOE basis, our overall DD&A rate of $6.16 per BOE for 2021 was 10% lower than the rate of $6.83 for the 2020 Successor Period and 55% lower than the rate of $13.69 per BOE for the 2020 Predecessor Period. The primary factors contributing to the lower DD&A rates during the Successor periods were impairment write-downs on proved oil and gas properties in the Williston Basin recognized in the first and second quarters of 2020 and the application of fresh start accounting upon emergence from the Chapter 11 Cases, under which we adjusted the value of our oil and gas properties down to their fair values on the Emergence Date. Refer to the "Fresh Start Accounting" footnote in the notes to the consolidated financial statements for more information.

Also contributing to the lower DD&A rate in 2021 were upward reserve revisions to proved reserves, which were largely driven by higher commodity prices during the period.

Exploration and Impairment Costs. The components of our exploration and impairment expense were as follows (in thousands):

	Successor		Predecessor	Non-GAAP
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Combined Year Ended December 31, 2020
Impairment	$ 6,707	$ 3,233	$ 4,161,885	$ 4,165,118
Exploration	4,074	4,632	22,945	27,577
Total	$ 10,781	$ 7,865	$ 4,184,830	$ 4,192,695

Impairment expense for both of the Successor periods primarily relates to the amortization of leasehold costs associated with individually insignificant unproved properties. Impairment expense for the 2020 Predecessor Period primarily related to (i) $4 billion in non-cash impairment charges for the partial write-down of proved oil and gas properties across our Williston Basin resource play due to a reduction in reserves driven by depressed oil prices and a resultant decline in future development plans for those properties at the time and (ii) $12 million in impairment write-downs of undeveloped acreage costs for leases where we no longer had plans to drill.

Exploration costs decreased $24 million during 2021 compared to the 2020 Combined YTD Period primarily due to $17 million of lower deficiency fees paid under our produced water disposal agreement at our Redtail field, which contract was rejected through the Chapter 11 Cases, and $3 million of lower geology-related general and administrative expenses due to a company restructuring in September 2020. Additionally, the 2020 Combined YTD Period includes $4 million of charges related to the write-off of certain suspended well costs for wells we no longer intend to drill and early rig termination fees incurred during the period.

General and Administrative Expenses. We report general and administrative ("G&A") expenses net of third-party reimbursements and internal allocations. The components of our G&A expenses were as follows (in thousands):

	Successor		Predecessor	Non-GAAP
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Combined Year Ended December 31, 2020
General and administrative expenses, other (1)	$ 111,171	$ 43,853	$ 135,746	$ 179,599
Stock-based compensation, non-cash	10,745	515	4,188	4,703
Reimbursements and allocations	(72,396)	(22,634)	(48,118)	(70,752)
General and administrative expenses, net (GAAP)	49,520	21,734	91,816	113,550
Less: Significant cost drivers (2)	-	(12,359)	(32,888)	(45,247)
Non-GAAP general and administrative expenses less significant cost drivers (3)	$ 49,520	$ 9,375	$ 58,928	$ 68,303

(1) General and administrative expenses, other excludes non-cash stock-based compensation expense and reimbursements and allocations. We believe general and administrative expenses, other provides useful information to compare our expenses between periods without the impact of the aforementioned items.

(2) Includes severance and restructuring charges, cash retention incentives for Predecessor executives and directors and third-party advisory and legal fees related to the Chapter 11 Cases and charges related to litigation and bankruptcy claim settlements discussed below.

(3) We believe non-GAAP general and administrative expenses less significant cost drivers is a useful measure for investors to understand our general and administrative expenses incurred on a recurring basis. We further believe investors may utilize this non-GAAP measure to estimate future general and administrative expenses. However, this non-GAAP measure is not a substitute for general and administrative expenses, net (GAAP), and there can be no assurance that any of the significant cost drivers excluded from such metric will not be incurred again in the future.

G&A expenses, other during 2021 decreased $68 million compared to the 2020 Combined YTD Period primarily due to $45 million of significant cost drivers incurred during the 2020 Combined YTD Period, including (i) $22 million in cash retention incentives paid to Predecessor executives and directors, (ii) $11 million of third party advisory and legal fees related to the Chapter 11 Cases that were incurred prior to the Petition Date or after the Emergence Date, (iii) $8 million of severance and restructuring costs for a company restructuring completed in the third quarter of 2020 and (iv) $5 million of additional costs related to litigation and bankruptcy settlements. In addition, compensation costs decreased by $17 million and corporate overhead costs decreased by $9 million as a result of the aforementioned company restructuring in the third quarter of 2020 and other cost reduction strategies implemented upon emergence from the Chapter 11 Cases, including the renegotiation of certain contracts.

G&A expense per BOE amounted to $1.48 during 2021, which represents a decrease of $1.67 per BOE (or 53%) from the 2020 Combined YTD Period. This decrease was mainly due to the overall decrease in G&A discussed above partially offset by lower overall production volumes between periods.

Derivative (Gain) Loss, Net. Our commodity derivative contracts are marked to market each reporting period with fair value gains and losses recognized immediately in earnings as derivative (gain) loss, net. Cash flow, however, is only impacted to the extent that settlements under these contracts result in us making or receiving a payment to or from the counterparty. Derivative (gain) loss, net, amounted to a loss of $520 million and a gain of $157 million for 2021 and the 2020 Combined YTD Period, respectively. These gains and losses relate to our collar, swap, basis swap and differential swap commodity derivative contracts and resulted from the upward and downward shifts, respectively, in the futures curve of forecasted commodity prices for crude oil, natural gas and NGLs during those periods.

For more information on our outstanding derivatives refer to the "Derivative Financial Instruments" footnote in the notes to the consolidated financial statements.

(Gain) Loss on Sale of Properties. During 2021, we sold all of our interests in the producing assets and undeveloped acreage, including the associated midstream assets, of our Redtail field located in the Denver-Julesburg Basin of Weld County, Colorado for aggregate sales proceeds of $171 million, which resulted in a pre-tax gain on sale of $86 million. The divestiture remains subject to a final settlement between Whiting and the buyer of the properties. Refer to the “Acquisitions and Divestitures” footnote in the consolidated financial statements for more information on this transaction. Additionally, during 2021, a series of non-core producing oil and gas properties were divested for aggregate sales proceeds of $7.4 million (before closing adjustments). As a result of one of these divestitures, our asset retirement obligation liability decreased by $10 million and we recognized a corresponding gain on sale of $10 million.

Interest Expense. The components of our interest expense were as follows (in thousands):

	Successor		Predecessor	Non-GAAP
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Combined Year Ended December 31, 2020
Credit agreements	$ 11,155	$ 6,570	$ 23,948	$ 30,518
Amortization of debt issue costs, discounts and premiums	3,554	1,257	13,536	14,793
Other	1,672	253	730	983
Notes	-	-	34,840	34,840
Total	$ 16,381	$ 8,080	$ 73,054	$ 81,134

The decrease in interest expense of $65 million during 2021 compared to the 2020 Combined YTD Period was primarily attributable to lower interest costs incurred on our notes and our credit agreements as well as lower amortization of debt issue costs, discounts and premiums. Upon filing of the Chapter 11 Cases on April 1, 2020, we stopped incurring interest on our notes, which resulted in a $35 million decrease in note interest expense between periods. In addition, the remaining unamortized debt issuance costs and premiums associated with these notes were written off on the Petition Date, resulting in an $11 million decrease in amortization expense between periods. Upon emergence from the Chapter 11 Cases, all outstanding obligations under our notes were cancelled in exchange for shares of Successor common stock. Refer to the “Chapter 11 Emergence” and “Long-Term Debt” footnotes in the notes to the consolidated financial statements for more information.

The decrease in interest expense incurred on our credit agreements of $19 million during 2021 compared to the 2020 Combined YTD Period resulted from lower borrowings outstanding between periods. Our weighted average borrowings outstanding under the Credit Agreement during 2021 were $189 million compared to $644 million of weighted average borrowings outstanding under the applicable Credit Agreements during the 2020 Combined YTD Period.

Our weighted average debt outstanding during 2021, consisting solely of borrowings under the Credit Agreement, carried a weighted average cash interest rate of 5.9%. Our weighted average debt outstanding during the 2020 Predecessor Period, consisting of the notes and borrowings outstanding on the Predecessor Credit Agreement, was $3.2 billion, with a weighted average cash interest rate of 2.8%. The lower interest rate during the 2020 Predecessor Period primarily relates to the discontinuation of interest on our senior notes beginning in April 2020 as a result of filing the Chapter 11 Cases.

Subsequent to our emergence from bankruptcy, our weighted average borrowings outstanding during the 2020 Successor Period were $410 million, with a weighted average cash interest rate of 4.8%.

Gain on Extinguishment of Debt. During the 2020 Predecessor Period, we paid $53 million to repurchase $73 million aggregate principal amount of our convertible senior notes and recognized a $23 million gain on extinguishment of debt. Refer to the “Long-Term Debt” footnote in the notes to consolidated financial statements for more information on this repurchase. Additionally, in March 2020, the holders of $3 million aggregate principal amount of our convertible senior notes elected to convert. Upon conversion, such holders of the converted convertible senior notes were entitled to receive an insignificant cash payment on April 1, 2020, which we did not pay in conjunction with the filing of the Chapter 11 Cases. As a result of such conversion we recognized a $3 million gain on extinguishment of debt during the 2020 Predecessor Period.

Reorganization Items, Net. During the 2020 Predecessor Period, we recognized a net gain of $217 million related to the Chapter 11 Cases consisting of (i) gains on settlement of certain liabilities, including our senior notes, upon consummation of the Plan, (ii) fresh start accounting fair value adjustments, (iii) legal and professional advisory fees recognized between the Petition Date and the Emergence Date and (iv) the write-off of debt issuance costs and premiums associated with our senior notes. Refer to the “Chapter 11 Emergence” and “Fresh Start Accounting” footnotes in the notes to the consolidated financial statements for more information on amounts recorded to reorganization items, net.

Income Tax Expense (Benefit). During the year ended December 31, 2021 we recognized $1 million of U.S. current income tax expense resulting in an overall effective tax rate of 0.2%, which is lower than the statutory income tax rate as a result of the full valuation allowance on our U.S. deferred tax assets (“DTAs”) as of December 31, 2021.

During the 2020 Combined YTD Period, we recorded a tax benefit of $68 million reflecting a reduction in the overall expected Canadian tax liability as a result of a legal entity restructuring we initiated during the period. Of this reduction, $55 million resulted from the implementation of fresh start accounting and was recorded during the 2020 Predecessor Period and $12 million resulted from the completion of the restructuring and was recorded during the 2020 Successor Period. The remaining $6 million Canadian tax liability was paid in the fourth quarter of 2020. Refer to the “Income Taxes” footnote in the notes to the consolidated financial statements for more information on the legal restructuring and related Canadian deferred tax liability.

We also recognized a $1 million U.S. income tax benefit during the 2020 Combined YTD Period related to an alternative minimum tax refund received. As a result of the full valuation allowance on our U.S. DTAs as of December 31, 2020 (Successor) and August 31, 2020 (Predecessor), no additional U.S. tax benefit or expense was recognized.

Our overall effective tax rate of 1.7% for the 2020 Combined YTD Period was lower than the U.S. statutory income tax rate as a result of the full valuation allowance on our U.S. DTAs and the reduction of our overall expected Canadian tax liability discussed above.

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

For discussion on the year ended December 31, 2020 (which includes the 2020 Successor Period and the 2020 YTD Predecessor Period) compared to the year ended December 31, 2019 (Predecessor), refer to Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” of our 2020 Annual Report on Form 10-K filed with the SEC on February 24, 2021 under the subheading “Successor Period and Current YTD Predecessor Period or Combined Current YTD Period Compared to Prior Predecessor YTD Period.”

Liquidity and Capital Resources

Overview. At December 31, 2021, we had $41 million of unrestricted cash on hand, no long-term debt and $1.7 billion of shareholders’ equity, while at December 31, 2020, we had $26 million of unrestricted cash on hand, $360 million of long-term debt and $1.2 billion of equity. We expect that our liquidity going forward will be primarily derived from cash flows from operating activities, cash on hand and availability under the Credit Agreement and that these sources of liquidity will be sufficient to provide us the ability to fund our material cash requirements, as described below, as well as our operating and development activities and planned capital programs. We may need to fund acquisitions or other business opportunities that support our strategy through additional borrowings or the issuance of common stock or other forms of equity.

Cash Flows. During 2021, we generated $740 million of cash from operating activities, an increase of $545 million from the 2020 Combined YTD Period. Cash provided by operating activities increased between periods primarily due to higher realized sales prices, as well as lower cash reorganization, G&A, interest and exploration expenses. These positive factors were partially offset by an increase in cash settlements paid on our commodity derivative contracts and higher production taxes and lease operating expenses between periods. Refer to “Results of Operations” for more information on the impact of volumes and prices on revenues and for more information on increases and decreases in certain expenses between periods. During 2021, cash flows from operating activities and $180 million of proceeds from the sale of properties were used for the net repayment of $360 million of outstanding borrowings under the Credit Agreement, to fund Williston Basin acquisitions totaling $306 million and for $234 million of drilling and development expenditures.

For discussion on cash flows for the 2020 Combined YTD Period compared to the year ended December 31, 2019 (Predecessor), refer to Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” of our 2020 Annual Report on Form 10-K filed with the SEC on February 24, 2021 under the subheading “Cash Flows.”

One of the primary sources of variability in our cash flows from operating activities is commodity price volatility, which we partially mitigate through the use of commodity derivative contracts. Oil accounted for 58% and 61% of our total production in 2021 and 2020, respectively. Natural gas accounted for 21% and 20% of our total production in 2021 and 2020, respectively. NGLs accounted for 21% and 19% of our total production in 2021 and 2020, respectively. As of February 17, 2022, we had crude oil derivative contracts (consisting of collars and swaps) covering the sale of 39,000 Bbl and 16,000 Bbl of oil per day for the remainder of 2022 and the first three quarters of 2023, respectively. As of February 17, 2022, we had natural gas derivative contracts (consisting of collars, swaps and basis swaps) covering the sale of 95,000 MMBtu and 61,000 MMBtu of natural gas per day through the remainder of 2022 and the first three quarters of 2023, respectively. As of February 17, 2022, we had NGL derivative contracts (consisting of swaps) covering the sale of 223,000 gallons of NGLs per day for the remainder of 2022. For more information on our outstanding derivatives refer to the "Derivative Financial Instruments" footnote in the notes to the consolidated financial statements.

Material Cash Requirements. Our material short-term cash requirements include dividend payments, payments under our short-term lease agreements, recurring payroll and benefits obligations for our employees, capital and operating expenditures and other working capital needs. Working capital, defined as total current assets less total current liabilities, fluctuates depending on commodity pricing and effective management of payables to our vendors and receivables from our purchasers and working interest partners. As commodity prices improve, our working capital requirements may increase as we spend additional capital, increase production and pay larger settlements on our outstanding commodity derivative contracts. Additionally, as discussed in "Recent Developments" above, on February 1, 2022 we entered into a purchase and sale agreement that results in a material short-term cash commitment of $240 million, subject to normal closing adjustments.

Our long-term material cash requirements from currently known obligations include repayment of anticipated outstanding borrowings and interest payment obligations under our Credit Agreement, settlements on our outstanding commodity derivative contracts, future obligations to plug, abandon and remediate our oil and gas properties at the end of their productive lives, operating and finance lease obligations and contracts to transport a minimum volume of crude oil and natural gas within specified time frames. The following table summarizes our estimated material cash requirements for known obligations as of December 31, 2021. This table does not include repayments of outstanding borrowings on our Credit Agreement, or the associated interest payments, as the timing and amount of borrowings and repayments cannot be forecasted with certainty and are based on working capital requirements, commodity prices and acquisition and divestiture activity, among other factors. As of December 31, 2021, we had no outstanding borrowings under our Credit Agreement. Refer to "Credit Agreement" below as well as the "Long-Term Debt" footnote in the notes to the consolidated financial statements for more information. This table also does not include amounts payable under obligations where we cannot forecast with certainty the amount and timing of such payments, including any amounts we may be obligated to pay under our derivative contracts, as such payments are dependent on commodity prices in effect at the time of settlement. Refer to the "Derivative Financial Instruments" footnote in the notes to the consolidated financial statements for further information on these contracts and their fair values as of December 31, 2021, which fair values represent the cash settlement amount required to terminate such instruments based on forward price curves for commodities as of that date. Refer to the "Commitments and Contingencies" footnote in the notes to the consolidated financial statements in Item 8 of this Annual Report on Form 10-K for more information on other obligations that we may have where the timing and amount of any payments is uncertain.

	Payments due by period (in thousands)				
Material Cash Requirements	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Asset retirement obligations (1)	$ 104,067	$ 10,152	$ 23,326	$ 22,923	$ 47,666
Operating leases (2)	20,977	3,572	6,205	3,844	7,356
Finance leases (2)	2,118	1,378	713	27	-
Total	$ 127,162	$ 15,102	$ 30,244	$ 26,794	$ 55,022

(1) Asset retirement obligations represent the present value of estimated amounts expected to be incurred in the future to plug and abandon oil and gas wells, remediate oil and gas properties and dismantle their related plants and facilities.

(2) We have operating and finance leases for corporate and field offices, midstream facilities, equipment and automobiles. The obligations reported above represent our minimum financial commitments pursuant to the terms of these contracts. Refer to the "Leases" footnote in the notes to the consolidated financial statements in Item 8 of this Annual Report on Form 10-K for more information on these leases.

Exploration and Development Expenditures. During 2021 and the 2020 Combined YTD Period, we incurred accrual basis exploration and development ("E&D") expenditures of $247 million and $209 million, respectively. Of these expenditures, 99% and 96%, respectively, were incurred in the Williston Basin of North Dakota and Montana, where we have focused our current development activities. Capital expenditures reported in the consolidated statements of cash flows are calculated on a cash basis, which differs from the accrual basis used to calculate the incurred capital expenditures as detailed in the table below:

	Successor		Predecessor	Non-GAAP	Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Combined Year Ended December 31, 2020	Year Ended December 31, 2019
Capital expenditures, accrual basis	$ 247,201	$ 23,992	$ 185,363	$ 209,355	$ 778,254
Decrease (increase) in accrued capital expenditures and other noncash capital activity	(12,764)	9,995	53,093	63,088	15,111
Capital expenditures, cash basis	$ 234,437	$ 33,987	$ 238,456	$ 272,443	$ 793,365

We continually evaluate our capital needs and compare them to our capital resources. Our 2022 E&D budget is a range of $360 million to $400 million, which we expect to fund with net cash provided by operating activities and cash on hand. Our level of E&D expenditures is largely discretionary, although a portion of our E&D expenditures are for non-operated properties where we have limited control over the timing and amount of such expenditures, and the amount of funds we devote to any particular activity may increase or decrease significantly depending on commodity prices, cash flows, available opportunities and development results, among other factors. We believe that we have sufficient liquidity and capital resources to execute our development plan over the next 12 months. With our expected cash flow streams, commodity price hedging strategies, current liquidity levels (primarily consisting of availability under the Credit Agreement) and flexibility to modify future capital expenditure programs, we expect to fund all planned capital programs, comply with our debt covenants and meet other obligations that may arise from our oil and gas operations.

Dividends. In February 2022, we announced that we would begin paying a quarterly dividend of $0.25 per share with the first dividend to be paid on March 15, 2022. While we believe that our future cash flows from operations can sustain this dividend, future dividends may change based on a variety of factors, including contractual restrictions, legal limitations, business developments and the judgment of our Board. There can be no guarantee that we will pay dividends or otherwise return capital to our shareholders in the future.

Credit Agreement. Whiting Petroleum Corporation, as parent guarantor, and Whiting Oil and Gas, as borrower, are parties to the Credit Agreement, a reserves-based credit facility with a syndicate of banks. The Credit Agreement had a borrowing base and aggregate commitments of $750 million as of December 31, 2021. As of December 31, 2021, we had no borrowings outstanding under the Credit Agreement with $749 million of available borrowing capacity, which was net of $1 million in letters of credit outstanding.

The borrowing base under the Credit Agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations on April 1 and October 1 of each year, as well as special redeterminations described in the Credit Agreement, which in each case may increase or decrease the borrowing base. Additionally, we can increase the aggregate commitments by up to an additional $750 million, subject to certain conditions.

Up to $50 million of the borrowing base may be used to issue letters of credit for the account of Whiting Oil and Gas or our other designated subsidiaries. As of December 31, 2021, $49 million was available for additional letters of credit under the Credit Agreement.

The Credit Agreement provides for interest only payments until maturity on April 1, 2024, when the agreement terminates and all outstanding borrowings are due. In addition, the Credit Agreement provides for certain mandatory prepayments, including a provision pursuant to which, if our cash balances are in excess of approximately $75 million during any given week, such excess must be utilized to repay borrowings under the Credit Agreement. Interest under the Credit Agreement accrues at our option at either (i) a base rate for a base rate loan plus a margin between 1.75% and 2.75% based on the ratio of outstanding borrowings and letters of credit to the lower of the current borrowing base or total commitments, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.5% per annum, or an adjusted LIBOR plus 1.0% per annum, or (ii) an adjusted LIBOR for a eurodollar loan plus a margin between 2.75% and 3.75% based on the ratio of outstanding borrowings and letters of credit to the lower of the current borrowing base or total commitments. Additionally, we incur commitment fees of 0.5% on the unused portion of the aggregate commitments of the lenders under the Credit Agreement, which are included as a component of interest expense.

The Credit Agreement contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of our lenders. The Credit Agreement also restricts our ability to make any dividend payments or cash distributions on our common stock except to the extent that we have distributable free cash flow and (i) have at least 20% of available borrowing capacity, (ii) have a consolidated net leverage ratio of less than or equal to 2.0 to 1.0, (iii) do not have a borrowing base deficiency and (iv) are not in default under the Credit Agreement. These restrictions apply to all of our restricted subsidiaries and are calculated in accordance with definitions contained in the Credit Agreement. The Credit Agreement requires us, as of the last day of any quarter, to maintain commodity hedges covering a minimum of 50% of our projected production for the succeeding twelve months, as reflected in the reserves report most recently provided by us to the lenders under the Credit Agreement. If our consolidated net leverage ratio equals or exceeds 1.0 to 1.0 as of the last day of any fiscal quarter, we will also be required to hedge 35% of our projected production for the next succeeding twelve months. We are also limited to hedging a maximum of 85% of our production from proved reserves. The Credit Agreement requires us to maintain the following ratios: (i) a consolidated current assets to consolidated current liabilities ratio of not less than 1.0 to 1.0 and (ii) a total debt to last four quarters' EBITDAX ratio of not greater than 3.5 to 1.0.

For further information on the loan security related to the Credit Agreement, refer to the "Long-Term Debt" footnote in the notes to the consolidated financial statements.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these statements in accordance with GAAP and SEC rules and regulations requires us to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, political environment, global economics, mechanical problems, general business conditions and other factors. A summary of our significant accounting policies is detailed in the "Summary of Significant Policies" footnote in the notes to the consolidated financial statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

Successful Efforts Accounting. We account for our oil and gas operations using the successful efforts method of accounting. Under this method, the fair value of property acquired and all costs associated with successful exploratory wells and all development wells are capitalized. Items charged to expense generally include geological and geophysical costs, costs of unsuccessful exploratory wells and oil and gas production costs. All of our properties are located within the continental United States.

Oil and Natural Gas Reserve Quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion, impairment of our oil and natural gas properties and our asset retirement obligations. Discounted future net cash flows derived from our reserve estimates were also utilized in establishing the fair value of our oil and natural gas properties upon the adoption of fresh start accounting on the Emergence Date. 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. Reserve quantities and future cash flows included in this report are prepared in accordance with guidelines established by the SEC and the FASB. The accuracy of our reserve estimates is a function of (i) the quality and quantity of available data, (ii) the interpretation of that data, (iii) the accuracy of various mandated economic assumptions, and (iv) the judgments of the persons preparing the estimates.

Our total proved reserves increased 66 MMBOE, or 25%, from December 31, 2020 to December 31, 2021. Refer to "Reserves" in Item 2 and "Supplemental Disclosures about Oil and Gas Producing Activities" in Item 8 of this Annual Report on Form 10-K for information on the change in reserves between periods. External petroleum engineers independently estimated all of the proved reserve quantities included in this Annual Report on Form 10-K. In connection with our external petroleum engineers performing their independent reserve estimations, we furnish them with the following information that they use in their evaluation: (1) technical support data, (2) technical analysis of geologic and engineering support information, (3) economic and production data, (4) our well ownership interests and (5) expected future development activity. The independent petroleum engineers, Netherland, Sewell & Associates, Inc., evaluated 100% of our estimated proved reserve quantities and their related pre-tax future net cash flows as of December 31, 2021. Estimates prepared by others may be higher or lower than our estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and gas that are ultimately recovered. For example, if the crude oil and natural gas prices used in our year-end reserve estimates increased or decreased by 10%, our proved reserve quantities at December 31, 2021 would have increased by 5 MMBOE (2%) or decreased by 7 MMBOE (2%), respectively, and the pre-tax PV10% of our proved reserves would have increased by $755 million (17%) or decreased by $752 million (17%), respectively. We continually make revisions to reserve estimates throughout the year as additional information becomes available. We make changes to depletion rates and impairment calculations (when impairment indicators arise) in the same period that changes to reserve estimates are made.

Depreciation, Depletion and Amortization. Our rate of recording DD&A is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions and future projections. If our estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, which in turn reduces our net income. Such a decline

in reserves may result from lower commodity prices or other changes to reserve estimates, as discussed above, and we are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploration and development program, as well as future economic conditions. Our DD&A rate declined significantly during both 2021 and the 2020 Successor Period as compared to the 2020 Predecessor Period as a result of our adoption of fresh start accounting on the Emergence Date, which resulted in a reduced book value of our oil and natural gas properties at that date as compared to the 2020 Predecessor Period.

Impairment of Oil and Gas Properties. We review the value of our oil and gas properties whenever management judges that events and circumstances indicate that the net carrying value of properties may not be recoverable. Such events and circumstances include, but are not limited to, declines in commodity prices, increases in operating costs, unfavorable reserve revisions, poor well performance, changes in development plans and potential property divestitures. Impairments of producing properties are determined by comparing their undiscounted future net cash flows to their net book values at the end of each period. If a property's net capitalized costs exceed undiscounted future net cash flows, the cost of the property is written down to "fair value," which is determined using discounted future net cash flows from the producing property. Different pricing assumptions or discount rates could result in a different calculated impairment. In addition to proved property impairments, we provide for impairments on significant undeveloped properties when we determine that the property will not be developed or a permanent impairment in value has occurred. Individually insignificant unproved properties are amortized on a composite basis, based on past success, experience and average remaining lease-term.

Income Taxes. We provide for income taxes in accordance with FASB ASC Topic 740 – *Income Taxes* ("ASC 740"). We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of our deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions, particularly as they relate to prevailing oil and natural gas prices.

Internal Revenue Code ("IRC") Section 382 addresses company ownership changes and specifically limits the utilization of certain deductions and other tax attributes on an annual basis following an ownership change. As a result of the Chapter 11 reorganization and related transactions, the Successor experienced an ownership change within the meaning of IRC Section 382 on the Emergence Date. This ownership change subjected certain of the Company's tax attributes to an IRC Section 382 limitation. The ownership changes and resulting annual limitation may result in the expiration of net operating loss carryforwards or other tax attributes otherwise available, with a corresponding decrease in the Company's valuation allowance.

We are subject to taxation in many jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions. If we ultimately determine that the payment of these liabilities will be unnecessary, we reverse the liability and recognize a tax benefit during the period in which we determine the liability no longer applies. Conversely, we record additional tax charges in a period in which we determine that a recorded tax liability is less than we expect the ultimate assessment to be.

Reorganization and Fresh Start Accounting. Effective April 1, 2020, as a result of the filing of the Chapter 11 Cases we began accounting and reporting according to FASB ASC Topic 852 – *Reorganizations* ("ASC 852"), which specifies the accounting and financial reporting requirements for entities reorganizing through chapter 11 bankruptcy proceedings. These requirements include distinguishing transactions associated with the reorganization and implementation of the plan of reorganization separate from activities related to ongoing operations of the business. Additionally upon emergence from the Chapter 11 Cases, ASC 852 requires us to allocate our reorganization value to our individual assets based on their estimated fair values, resulting in a new entity for financial reporting purposes. After the Emergence Date, the accounting and reporting requirements of ASC 852 are no longer applicable and have no impact on the Successor periods.

Effects of Inflation and Pricing

The oil and gas industry is very cyclical, and the demand for goods and services of oil field companies, suppliers and others associated with the industry puts extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and not adjust downward in proportion to prices. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, depletion expense, impairment assessments of oil and gas properties and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. Higher demand in the industry could result in increases in the costs of materials, services and personnel. Although commodity prices declined sharply during the first part of 2020, the costs of oil field goods and services were slower to decline in response. As commodity prices began to recover during the second half of 2020 and during 2021, the cost of oil field goods and services also rose materially in response to increased competition resulting from increased drilling and completion activity as well as inflationary cost pressures on the U.S. economy. We expect these inflationary pressures to continue throughout 2022.

Forward-Looking Statements

This report contains statements that we believe to be "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than historical facts, including, without limitation, statements regarding our future financial position, business strategy, dividends and other forms of return of capital, acquisitions and divestitures, projected revenues, earnings, returns, costs, capital expenditures, cash flows and debt levels, and plans and objectives of management for future operations, are forward-looking statements. When used in this report, words such as "expect," "intend," "plan," "estimate," "anticipate," "believe" or "should" or the negative thereof or variations thereon or similar terminology are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements.

These risks and uncertainties include, but are not limited to, risks associated with:

- declines in, or extended periods of low oil, NGL or natural gas prices;
- the occurrence of epidemic or pandemic diseases, including the coronavirus pandemic;
- action or inaction of the Organization of Petroleum Exporting Countries and other oil exporting nations to set and maintain production levels;
- the impacts of hedging on our results of operations;
- regulatory developments, including the potential shutdown of the Dakota Access Pipeline and new or amended federal, state and local initiatives relating to the regulation of hydraulic fracturing, air emissions and other aspects of oil and gas operations that could have a negative effect on the oil and gas industry and/or increase costs of compliance;
- the geographic concentration of our operations;
- our inability to access oil and gas markets due to market conditions or operational impediments;
- adequacy of midstream and downstream transportation capacity and infrastructure;
- shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and completion services;
- adverse weather conditions that may negatively impact development or production activities;
- potential losses and claims resulting from our oil and gas operations, including uninsured or underinsured losses;
- lack of control over non-operated properties;
- cybersecurity attacks or failures of our telecommunication and other information technology infrastructure;
- revisions to reserve estimates as a result of changes in commodity prices, regulation and other factors;
- inaccuracies of our reserve estimates or our assumptions underlying them;
- impact of negative shifts in investor sentiment and public perception towards the oil and gas industry and corporate governance standards;
- climate change issues;
- litigation and other legal proceedings; and
- other risks described under the caption "Risk Factors" in Item 1A of this Annual Report on Form 10-K.

We assume no obligation, and disclaim any duty, to update the forward-looking statements in this Annual Report on Form 10-K.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

The price we receive for our oil, NGL and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Crude oil, NGL and natural gas are commodities, and their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil, NGLs and natural gas have been volatile, and these markets will likely continue to be volatile in the future.

We periodically enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to oil, NGL and natural gas price volatility. Our derivative contracts have traditionally been two-way collars, swaps, basis swaps and differential swaps although we evaluate and have entered into other forms of derivative instruments as well. We do not apply hedge accounting, and therefore all changes in commodity derivative fair values are recorded immediately to earnings.

Crude Oil, Natural Gas and NGL Collars, Swaps and Basis Swaps. Our hedging portfolio currently consists of crude oil, natural gas and NGL collars and swaps, as well as natural gas basis swaps. Refer to the "Derivative Financial Instruments" footnote in the notes to the consolidated financial statements for a description and list of our outstanding derivative contracts at December 31, 2021.

Our collar contracts have the effect of providing a protective floor, while allowing us to share in upward pricing movements up to the ceiling price. Our fixed-price swap contracts entitle us to receive settlement from the counterparty in amounts, if any, by which the settlement price for the applicable calculation period is less than the fixed price, or require us to pay the counterparty if the settlement price for the applicable calculation period is more than the fixed price. Our basis swap contracts guarantee us a fixed price differential to NYMEX and the referenced index price, with settlement terms based on the difference between the floating market price differential and the fixed price differential.

The fair value of our oil derivative positions at December 31, 2021 was a net liability of $231 million. A hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve for crude oil as of December 31, 2021 would cause an increase of $109 million or a decrease of $106 million, respectively, in this fair value liability. The fair value of our natural gas derivative positions was a net liability of $25 million. A hypothetical upward or downward shift of 10% per MMBtu in the NYMEX forward curve for natural gas as of December 31, 2021 would cause an increase of $9 million or a decrease of $12 million, respectively, in this fair value liability. The fair value of our NGL derivative positions was a net asset of $3 million. A hypothetical upward or downward shift of 10% per Bbl in the Mont Belvieu and Conway forward curves for propane as of December 31, 2021 would cause a decrease or increase, respectively, of $4 million in this fair value asset.

While these collars, fixed-price swaps and basis swaps are designed to decrease our exposure to downward price movements, they also have the effect of limiting the benefit of (i) price increases above the ceiling with respect to the collars, (ii) upward price movements generally with respect to the fixed-price swaps and (iii) decreasing floating market differentials relative to NYMEX with respect to the basis swaps and differential swaps.

Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Whiting Petroleum Corporation
Denver, Colorado

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Whiting Petroleum Corporation and subsidiaries (the "Company") as of December 31, 2021 and 2020, the related consolidated statements of operations, stockholders' equity, and cash flows for the year ended December 31, 2021 and the period from September 1, 2020 to December 31, 2020 (Successor Company operations), and the periods from January 1, 2020 to August 31, 2020 and January 1, 2019 to December 31, 2019 (Predecessor Company operations), and the related notes (collectively referred to as the "financial statements"). In our opinion, the Successor 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 the year ended December 31, 2021 and for the period of September 1, 2020 to December 31, 2020, in conformity with accounting principles generally accepted in the United States of America. Further, in our opinion, the Predecessor financial statements present fairly, in all material respects, the results of its operations and cash flows for the periods from January 1, 2020 to August 31, 2020 and January 1, 2019 to December 31, 2019, 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 February 23, 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 audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

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

Proved Oil and Natural Gas Property and Depletion — Oil and Natural Gas Reserve Quantities — Refer to Note 1 to the financial statements

Critical Audit Matter Description

The Company's proved oil and natural gas properties are depleted using the units of production method based on the Company's oil and natural gas reserves. The development of the Company's oil and natural gas reserve quantities required management to make significant estimates and assumptions, including those related to management's five-year property development plan. The Company engaged a third-party engineering firm to estimate oil and natural gas quantities using generally accepted methods, calculation procedures and engineering data. Changes in these estimates or engineering data could have a significant impact on the amount of depletion. The proved oil and natural gas properties balance was $1.8 billion as of December 31, 2021, net of accumulated depreciation, depletion, and amortization. Depreciation, depletion and amortization expense was $0.2 billion for the year ended December 31, 2021.

Given the significant judgments made by management, performing audit procedures to evaluate the Company's oil and natural gas reserve quantities, including management's estimates related to its five-year property development plan, requires 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 estimates related to oil and natural gas reserves quantities and converting proved undeveloped oil and natural gas reserves to proved developed properties within five years included the following, among others:

- We tested the operating effectiveness of controls related to the Company's estimation of oil and natural gas reserve quantities, including controls relating to management's five-year property development plan.

- We evaluated the Company's estimated proved reserve quantities and reasonableness of management's five-year property development plan by comparing the forecasts to:

    - Historical conversions of proved undeveloped oil and natural gas reserves into proved developed oil and natural gas reserves.

    - Working capital and future cash flows to support development of proved undeveloped reserves into proved developed oil and natural gas reserves.

    - Internal communications to management and the Board of Directors.

    - Permits and approval for expenditures.

    - 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 Company's estimates of future production volumes by completing a retrospective comparison to historical production.

- We evaluated the experience, qualifications and objectivity of management's expert, a third-party engineering firm, including the methodologies and calculation procedures used to estimate oil and natural gas reserves and performed analytical procedures on the reserve quantities.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 23, 2022

We have served as the Company's auditor since 2003.

WHITING PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS
(in thousands, except share and per share data)

	Successor	
	December 31, 2021	**December 31, 2020**
ASSETS		
Current assets:		
Cash, cash equivalents and restricted cash	$ 41,245	$ 28,367
Accounts receivable trade, net	279,865	142,830
Prepaid expenses and other	17,158	19,224
Total current assets	338,268	190,421
Property and equipment:		
Oil and gas properties, successful efforts method	2,274,908	1,812,601
Other property and equipment	61,624	74,064
Total property and equipment	2,336,532	1,886,665
Less accumulated depreciation, depletion and amortization	(254,237)	(73,869)
Total property and equipment, net	2,082,295	1,812,796
Other long-term assets	37,368	40,723
TOTAL ASSETS	$ 2,457,931	$ 2,043,940
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable trade	$ 48,641	$ 23,697
Revenues and royalties payable	258,527	151,196
Accrued capital expenditures	38,914	20,155
Accrued liabilities and other	30,726	42,007
Accrued lease operating expenses	32,408	23,457
Taxes payable	18,864	11,997
Derivative liabilities	209,653	49,485
Total current liabilities	637,733	321,994
Long-term debt	-	360,000
Asset retirement obligations	93,915	91,864
Operating lease obligations	14,710	17,415
Long-term derivative liabilities	46,720	9,750
Other long-term liabilities	1,228	14,113
Total liabilities	794,306	815,136
Commitments and contingencies		
Equity:		
Common stock, $0.001 par value, 500,000,000 shares authorized; 39,133,637 issued and outstanding as of December 31, 2021 and 38,051,125 issued and outstanding as of December 31, 2020	39	38
Additional paid-in capital	1,196,607	1,189,693
Accumulated earnings	466,979	39,073
Total equity	1,663,625	1,228,804
TOTAL LIABILITIES AND EQUITY	$ 2,457,931	$ 2,043,940

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

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Successor		Predecessor	
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Year Ended December 31, 2019
OPERATING REVENUES				
Oil, NGL and natural gas sales	$ 1,511,837	$ 273,358	$ 459,004	$ 1,572,245
Purchased gas sales	21,644	-	-	-
Total operating revenues	1,533,481	273,358	459,004	1,572,245
OPERATING EXPENSES				
Lease operating expenses	242,476	73,981	158,228	328,427
Transportation, gathering, compression and other	30,107	8,038	22,266	42,438
Purchased gas expense	17,572	-	-	-
Production and ad valorem taxes	110,416	24,150	41,204	138,212
Depreciation, depletion and amortization	206,475	77,502	338,757	816,488
Exploration and impairment	10,781	7,865	4,184,830	54,738
General and administrative	49,520	21,734	91,816	132,609
Derivative (gain) loss, net	520,131	24,714	(181,614)	53,769
(Gain) loss on sale of properties	(95,611)	395	927	1,964
Amortization of deferred gain on sale	-	-	(5,116)	(9,069)
Total operating expenses	1,091,867	238,379	4,651,298	1,559,576
INCOME (LOSS) FROM OPERATIONS	441,614	34,979	(4,192,294)	12,669
OTHER INCOME (EXPENSE)				
Interest expense	(16,381)	(8,080)	(73,054)	(191,047)
Gain on extinguishment of debt	-	-	25,883	7,830
Interest income and other	3,583	136	211	1,602
Reorganization items, net	-	-	217,419	-
Total other income (expense)	(12,798)	(7,944)	170,459	(181,615)
INCOME (LOSS) BEFORE INCOME TAXES	428,816	27,035	(4,021,835)	(168,946)
INCOME TAX EXPENSE (BENEFIT)				
Current	910	2,463	2,718	-
Deferred	-	(14,501)	(59,092)	72,220
Total income tax expense (benefit)	910	(12,038)	(56,374)	72,220
NET INCOME (LOSS)	$ 427,906	$ 39,073	$ (3,965,461)	$ (241,166)
INCOME (LOSS) PER COMMON SHARE				
Basic	$ 10.97	$ 1.03	$ (43.37)	$ (2.64)
Diluted	$ 10.78	$ 1.03	$ (43.37)	$ (2.64)
WEIGHTED AVERAGE SHARES OUTSTANDING				
Basic	39,006	38,080	91,423	91,285
Diluted	39,692	38,119	91,423	91,285

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

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Successor		Predecessor	
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Year Ended December 31, 2019
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income (loss)	$ 427,906	$ 39,073	$ (3,965,461)	$ (241,166)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation, depletion and amortization	206,475	77,502	338,757	816,488
Deferred income tax benefit	-	(14,501)	(59,092)	72,220
Amortization of debt issuance costs, debt discount and debt premium	3,554	1,258	13,535	28,340
Stock-based compensation	10,745	515	4,188	7,721
Amortization of deferred gain on sale	-	-	(5,116)	(9,069)
(Gain) loss on sale of properties	(95,611)	395	927	1,964
Oil and gas property impairments	6,707	3,233	4,161,885	17,866
Gain on extinguishment of debt	-	-	(25,883)	(7,830)
Non-cash derivative (gain) loss	196,439	20,772	(136,131)	78,626
Non-cash reorganization items, net	-	-	(274,588)	-
Other, net	(5,464)	(1,761)	(223)	(1,352)
Changes in current assets and liabilities:				
Accounts receivable trade, net	(140,102)	(7,100)	181,416	(24,343)
Prepaid expenses and other	4,891	1,989	(5,491)	7,165
Accounts payable trade and accrued liabilities	17,096	(42,922)	(46,734)	40,117
Revenues and royalties payable	100,505	5,690	(56,504)	(26,274)
Taxes payable	7,102	(1,975)	(12,872)	(4,513)
Net cash provided by operating activities	740,243	82,168	112,613	755,960
CASH FLOWS FROM INVESTING ACTIVITIES				
Drilling and development capital expenditures	(234,437)	(33,987)	(238,456)	(793,365)
Acquisition of oil and gas properties	(306,487)	(166)	(493)	(6,031)
Other property and equipment	457	(2,486)	(1,072)	(6,451)
Proceeds from sale of properties	180,271	532	29,273	72,000
Net cash used in investing activities	(360,196)	(36,107)	(210,748)	(733,847)
CASH FLOWS FROM FINANCING ACTIVITIES				
Borrowings under Credit Agreement	1,831,000	272,500	425,328	-
Repayments of borrowings under Credit Agreement	(2,191,000)	(337,828)	-	-
Borrowings under Predecessor Credit Agreement	-	-	1,185,000	2,650,000
Repayments of borrowings under Predecessor Credit Agreement	-	-	(1,402,259)	(2,275,000)
Repurchase of 1.25% Convertible Senior Notes due 2020	-	-	(52,890)	(297,000)
Repurchase of 5.75% Senior Notes due 2021	-	-	-	(95,279)
Debt issuance and extinguishment costs	(73)	-	(12,784)	(819)
Principal payments on finance lease obligations	(4,020)	(1,773)	(3,198)	(5,140)
Restricted stock used for tax withholdings	(3,076)	-	(307)	(3,830)
Net cash provided by (used in) financing activities	$ (367,169)	$ (67,101)	$ 138,890	$ (27,068)

(Continued)

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Successor		Predecessor	
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Year Ended December 31, 2019
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	$ 12,878	$ (21,040)	$ 40,755	$ (4,955)
CASH, CASH EQUIVALENTS AND RESTRICTED CASH				
Beginning of period	28,367	49,407	8,652	13,607
End of period	$ 41,245	$ 28,367	$ 49,407	$ 8,652
SUPPLEMENTAL CASH FLOW DISCLOSURES				
Income taxes paid (refunded), net	$ -	$ 6,209	$ (1,028)	$ (7,508)
Interest paid, net of amounts capitalized	$ 12,134	$ 6,322	$ 80,220	$ 163,859
Cash paid for reorganization items	$ 396	$ 22,248	$ 33,238	$ -
NONCASH INVESTING ACTIVITIES				
Accrued capital expenditures and accounts payable related to property additions	$ 42,335	$ 21,531	$ 26,796	$ 86,088
Leasehold improvements paid for by third party lessor under office lease agreement	$ 375	$ 99	$ 49	$ 10,422
NONCASH FINANCING ACTIVITIES [(1)]				
Derivative termination settlement payments used to repay borrowings under Predecessor Credit Agreement	$ -	$ -	$ 157,741	$ -

(Concluded)

(1) Refer to the "Leases" footnote in the notes to the consolidated financial statements for discussion of right-of-use assets obtained in exchange for finance lease liabilities.

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

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY
(in thousands)

	Common Stock		Additional	Accumulated	Total
	Shares	Amount	Paid-in Capital	Earnings (Deficit)	Equity
BALANCES - January 1, 2019 (Predecessor)	92,067	$ 92	$ 6,414,170	$ (2,143,946)	$ 4,270,316
Net loss	-	-	-	(241,166)	(241,166)
Adjustment to equity component of Convertible Senior Notes upon partial extinguishment	-	-	(8,070)	-	(8,070)
Restricted stock issued	113	-	-	-	-
Restricted stock forfeited	(286)	-	-	-	-
Restricted stock used for tax withholdings	(150)	-	(3,830)	-	(3,830)
Stock-based compensation	-	-	7,721	-	7,721
BALANCES - December 31, 2019 (Predecessor)	91,744	92	6,409,991	(2,385,112)	4,024,971
Net loss	-	-	-	(3,965,461)	(3,965,461)
Adjustment to equity component of Convertible Senior Notes upon partial extinguishment	-	-	(3,461)	-	(3,461)
Restricted stock issued	194	-	-	-	-
Restricted stock forfeited	(238)	-	-	-	-
Restricted stock used for tax withholdings	(58)	-	(308)	-	(308)
Stock-based compensation	-	-	4,188	-	4,188
Cancellation of Predecessor stock	(91,642)	(92)	(6,410,410)	6,350,573	(59,929)
BALANCES - August 31, 2020 (Predecessor)	-	$ -	$ -	$ -	$ -
Issuance of Successor equity	38,051	$ 38	$ 1,159,818	$ -	$ 1,159,856
Issuance of Successor warrants	-	-	29,360	-	29,360
BALANCES - September 1, 2020 (Successor)	38,051	38	1,189,178	-	1,189,216
Net income	-	-	-	39,073	39,073
Stock-based compensation	-	-	515	-	515
BALANCES - December 31, 2020 (Successor)	38,051	38	1,189,693	39,073	1,228,804
Net income	-	-	-	427,906	427,906
Common stock issued in settlement of bankruptcy claims	949	1	(1)	-	-
Restricted stock issued	206	-	-	-	-
Restricted stock used for tax withholdings	(72)	-	(3,076)	-	(3,076)
Stock-based compensation	-	-	9,991	-	9,991
BALANCES - December 31, 2021 (Successor)	39,134	$ 39	$ 1,196,607	$ 466,979	$ 1,663,625

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

WHITING PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations—Whiting Petroleum Corporation, a Delaware corporation, is an independent oil and gas company engaged in the development, production and acquisition of crude oil, NGLs and natural gas primarily in the Rocky Mountains region of the United States. Unless otherwise specified or the context otherwise requires, all references in these notes to "Whiting" or the "Company" are to Whiting Petroleum Corporation together with its consolidated subsidiaries, Whiting Oil and Gas Corporation ("Whiting Oil and Gas" or "WOG"), Whiting US Holding Company, Whiting Canadian Holding Company ULC, Whiting Resources LLC ("WRC," formerly Whiting Resources Corporation) and Whiting Programs, Inc. In September 2020, Whiting US Holding Company merged with and into WOG with WOG surviving, and WRC transferred all of its operating assets to WOG. In November 2020, WRC, over a series of steps, was amalgamated with Whiting Canadian Holding Company ULC and subsequently dissolved. When the context requires, the Company refers to these entities separately.

Voluntary Reorganization under Chapter 11 of the Bankruptcy Code—On April 1, 2020 (the "Petition Date"), Whiting Petroleum Corporation, Whiting Oil and Gas, Whiting US Holding Company, Whiting Canadian Holding Company ULC and Whiting Resources Corporation (collectively, the "Debtors") commenced voluntary cases (the "Chapter 11 Cases") under chapter 11 of the Bankruptcy Code. On June 30, 2020, the Debtors filed the Joint Chapter 11 Plan of Reorganization of Whiting Petroleum Corporation and its Debtor affiliates (as amended, modified and supplemented, the "Plan"). On August 14, 2020, the Bankruptcy Court confirmed the Plan and on September 1, 2020 (the "Emergence Date"), the Debtors satisfied all conditions required for Plan effectiveness and emerged from the Chapter 11 Cases.

Upon emergence, the Company adopted fresh start accounting in accordance with FASB ASC Topic 852 – Reorganizations ("ASC 852"), which specifies the accounting and financial reporting requirements for entities reorganizing through chapter 11 bankruptcy proceedings. The application of fresh start accounting resulted in a new basis of accounting and the Company becoming a new entity for financial reporting purposes. As a result of the implementation of the Plan and the application of fresh start accounting, the consolidated financial statements after the Emergence Date are not comparable to the consolidated financial statements before that date and the historical financial statements on or before the Emergence Date are not a reliable indicator of the Company's financial condition and results of operations for any period after its adoption of fresh start accounting. Refer to the "Fresh Start Accounting" footnote for more information. References to "Successor" refer to the Company and its financial position and results of operations after the Emergence Date. References to "Predecessor" refer to the Company and its financial position and results of operations on or before the Emergence Date. References to "2020 Successor Period" relate to the period of September 1, 2020 through December 31, 2020. References to "2020 Predecessor Period" relate to the period of January 1, 2020 through August 31, 2020. The Company previously evaluated the events between August 31, 2020 and September 1, 2020 and concluded that the use of an accounting convenience date of August 31, 2020 did not have a material impact on the Company's financial position or results of operations.

During the 2020 Predecessor Period, the Company applied ASC 852 in preparing the consolidated financial statements, which requires distinguishing transactions associated with the reorganization separate from activities related to the ongoing operations of the business. Accordingly, pre-petition liabilities that could have been impacted by the chapter 11 proceedings were classified as liabilities subject to compromise. Additionally, certain expenses, realized gains and losses and provisions for losses that were realized or incurred during the Chapter 11 Cases, including adjustments to the carrying value of certain assets and indebtedness were recorded as reorganization items, net in the consolidated statements of operations for the relevant Predecessor periods. Refer to the "Chapter 11 Emergence" footnote for more information on the events of the bankruptcy proceedings as well as the accounting and reporting impacts of the reorganization during the 2020 Predecessor Period.

Basis of Presentation of Consolidated Financial Statements—The consolidated financial statements have been prepared in accordance with GAAP and SEC rules and regulations and include the accounts of Whiting Petroleum Corporation and its consolidated subsidiaries. Investments in entities which give Whiting significant influence, but not control, over the investee are accounted for using the equity method. Under the equity method, investments are stated at cost plus the Company's equity in undistributed earnings and losses. All intercompany balances and transactions have been eliminated upon consolidation.

Reclassifications—Certain prior period balances in the consolidated balance sheets have been combined or reclassified to conform to current period presentation. Such reclassifications had no impact on net income (loss), cash flows or shareholders' equity previously reported.

Use of Estimates—The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Items subject to such estimates and assumptions include (i) oil and natural gas reserves; (ii) impairment tests of long-lived assets; (iii) depreciation, depletion and amortization; (iv) asset retirement obligations; (v) assignment of fair value and allocation of purchase price in connection with business combinations, including the determination of any resulting goodwill; (vi) income taxes; (vii) accrued liabilities; (viii) valuation of derivative instruments; and (ix) accrued revenue and related receivables. Although management believes these estimates are reasonable, actual results could differ from these estimates. Further, these estimates and other factors, including those outside of the Company's control, such as the impact of lower commodity prices, may have a significant negative impact to the Company's business, financial condition, results of operations and cash flows.

Fair Value Measurements—The Company follows FASB ASC Topic 820 – *Fair Value Measurement* ("ASC 820") which establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1: Quoted Prices in Active Markets for Identical Assets – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2: Significant Other Observable Inputs – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

- Level 3: Significant Unobservable Inputs – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon 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 in its entirety requires judgment and considers factors specific to the asset or liability.

Cash, Cash Equivalents and Restricted Cash—Cash equivalents consist of demand deposits and highly liquid investments which have an original maturity of three months or less. Cash and cash equivalents potentially subject the Company to a concentration of credit risk as substantially all of its deposits held in financial institutions were in excess of the Federal Deposit Insurance Corporation ("FDIC") insurance limits as of December 31, 2021 and 2020. The Company maintains its cash and cash equivalents in the form of money market and checking accounts with financial institutions that are also lenders under the Credit Agreement. The Company has not experienced any losses on its deposits of cash and cash equivalents.

Restricted cash as of December 31, 2020 consists of funds remaining in a professional fee escrow account that were reserved to pay certain professional fees upon emergence from the Chapter 11 Cases (the "Professional Fee Escrow Account").

The following table provides a reconciliation of cash, cash equivalents and restricted cash reported within the consolidated balance sheets and statements of cash flows (in thousands):

	Successor	
	December 31, 2021	**December 31, 2020**
Cash and cash equivalents	$ 41,245	$ 25,607
Restricted cash	-	2,760
Total cash, cash equivalents and restricted cash	$ 41,245	$ 28,367

Accounts Receivable Trade—Whiting's accounts receivable trade consist mainly of receivables from oil and gas purchasers and joint interest owners on properties the Company operates. The Company's collection risk is inherently low based on the viability of its oil and gas purchasers as well as its general ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. The Company's oil and gas receivables are generally collected within two months, and to date, the Company has not experienced material credit losses.

The Company routinely evaluates expected credit losses for all material trade and other receivables to determine if an allowance for credit losses is warranted. Expected credit losses are estimated based on (i) historic loss experience for pools of receivable balances with similar characteristics, (ii) the length of time balances have been outstanding and (iii) the economic status of each counterparty. These loss estimates are then adjusted for current and expected future economic conditions, which may include an assessment of the probability of non-payment, financial distress or expected future commodity prices and the impact that any current or future conditions could have on a counterparty's credit quality and liquidity. As of December 31, 2020 (Successor), the Company had an immaterial allowance for credit losses due to the application of fresh start accounting. There were no material changes in the estimate of expected credit losses at December 31, 2021.

Inventories—Materials and supplies inventories consist primarily of tubular goods and production equipment, carried at weighted-average cost. Materials and supplies are included in other property and equipment and totaled $33 million and $29 million as of December 31, 2021 and 2020 (Successor), respectively. Crude oil in tanks inventory is carried at the lower of the estimated cost to produce or net realizable value. Oil in tanks is included in prepaid expenses and other and totaled $4 million and $6 million as of December 31, 2021 and 2020 (Successor), respectively.

Oil and Gas Properties

Proved. The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and development costs are capitalized when incurred and depleted on a unit-of-production basis over the remaining life of proved reserves and proved developed reserves, respectively. Costs of drilling exploratory wells are initially capitalized but are charged to expense if the well is determined to be unsuccessful.

The Company assesses its proved oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the assets may not be recoverable. Such events include, but are not limited to, declines in commodity prices, increases in operating costs, unfavorable reserve revisions, poor well performance, changes in development plans and potential property divestitures. The impairment test compares undiscounted future net cash flows to the assets' net book value. These undiscounted cash flows are driven by significant assumptions, including the Company's expected future development activity, reserve estimates, forecasted pricing, future operating costs, capital expenditures and severance taxes. If the net capitalized costs exceed undiscounted future net cash flows, then the cost of the property is written down to fair value utilizing a discounted future net cash flow analysis.

Impairment expense for proved properties totaled $4 billion for the 2020 Predecessor Period, which is reported in exploration and impairment expense in the consolidated statements of operations.

Net carrying values of retired, sold or abandoned properties that constitute less than a complete unit of depreciable property are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized in income. Gains or losses from the disposal of complete units of depreciable property are recognized to earnings.

Unproved. Unproved properties consist of costs to acquire undeveloped leases as well as purchases of unproved reserves. Undeveloped lease costs and unproved reserve acquisitions are capitalized, and individually insignificant unproved properties are amortized on a composite basis, based on average remaining lease-term and the historical experience of developing acreage in a particular prospect. The Company evaluates significant unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. When successful wells are drilled on undeveloped leaseholds, unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis.

Exploratory. Geological and geophysical costs, including exploratory seismic studies, and the costs of carrying and retaining unproved acreage are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

Costs of drilling exploratory wells are initially capitalized, pending determination of whether the well has found proved reserves. If an exploratory well has not found proved reserves, the costs of drilling the well and other associated costs are charged to expense. Costs incurred for exploratory wells that find reserves, which cannot yet be classified as proved, continue to be capitalized if (i) the well has found a sufficient quantity of reserves to justify completion as a producing well and (ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met, or if the Company obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well costs, net of any salvage value, are expensed.

Leases—The Company accounts for leases in accordance with FASB ASC Topic 842 – *Leases* ("ASC 842"). The Company has elected certain practical expedients available under ASC 842 including the short-term lease recognition exemption for all classes of underlying assets. Accordingly, leases with a term of one year or less have not and will not be recognized in the consolidated balance sheets. The Company has also elected the practical expedient to not separate lease and non-lease components contained within a single agreement for all classes of underlying assets.

Other Property and Equipment—Other property and equipment consists of materials and supplies inventories, carried at weighted-average cost, and furniture and fixtures, buildings and leasehold improvements, which are stated at cost and depreciated using the straight-line method over their estimated useful lives ranging from 4 to 30 years. Additionally, other property and equipment includes finance lease right-of-use assets for automobiles, which are depreciated using the straight-line method over the shorter of (i) their lease term or (ii) their estimated useful lives of 5 years. Refer to the "Leases" footnote for additional information on these lease assets.

Debt Issuance Costs—Debt issuance costs related to the Credit Agreement are included in other long-term assets and are amortized to interest expense on a straight-line basis over the term of the agreement. As a result of the Chapter 11 Cases and the adoption of ASC 852, the Company wrote off all unamortized issuance costs related to its senior notes on the Petition Date. Refer to the "Chapter 11 Emergence" and "Fresh Start Accounting" footnotes for more information.

Debt Discounts and Premiums—Debt discounts and premiums related to the Company's senior notes and convertible senior notes were previously included as a deduction from or addition to the carrying amount of the long-term debt and were amortized to interest expense using the effective interest method over the term of the related notes. As a result of the Chapter 11 Cases and the adoption of ASC 852, the Company wrote off all unamortized premium balances related to its notes on the Petition Date. Refer to the "Chapter 11 Emergence" and "Fresh Start Accounting" footnotes for more information.

Derivative Instruments—The Company enters into derivative contracts, primarily collars and swaps, to manage its exposure to commodity price risk. Whiting follows FASB ASC Topic 815 – *Derivatives and Hedging* ("ASC 815"), to account for its derivative financial instruments. All derivative instruments, other than those that meet the "normal purchase normal sale" exclusion, are recorded in the consolidated balance sheets as either an asset or liability measured at fair value. Gains and losses from changes in the fair value of derivative instruments are recognized immediately in earnings, unless the derivative meets specific hedge accounting criteria and the derivative has been designated as a hedge. The Company does not currently apply hedge accounting to any of its outstanding derivative instruments, and as a result, all changes in derivative fair values are recognized currently in earnings.

Cash flows from derivatives used to manage commodity price risk are classified in operating activities along with the cash flows of the underlying hedged transactions. The Company does not enter into derivative instruments for speculative or trading purposes. Refer to the "Derivative Financial Instruments" footnote for further information.

Asset Retirement Obligations and Environmental Costs—Asset retirement obligations relate to future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. The Company follows FASB ASC Topic 410 – *Asset Retirement and Environmental Obligations*, to determine its asset retirement obligation amounts by calculating the present value of the estimated future cash outflows associated with its plugging and abandonment obligations. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred (typically when a well is completed or acquired or when an asset is installed at the production location), and the cost of such liability increases the carrying amount of the related long-lived asset by the same amount. The liability is accreted each period through charges to depreciation, depletion and amortization expense, and the capitalized cost is depleted on a unit-of-production basis over the proved developed reserves of the related asset. Revisions typically occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells, and such revisions result in adjustments to the related capitalized asset and corresponding liability.

Deferred Gain on Sale—The Company recorded a deferred gain on sale related to the sale of 18,400,000 Whiting USA Trust II ("Trust II") units, which was being amortized to income based on the unit-of-production method. As a result of the Chapter 11 Cases and the adoption of ASC 852, the Company wrote off the remaining deferred gain to "Reorganization items, net" in the consolidated statements of operations during the 2020 Predecessor Period. Refer to the "Chapter 11 Emergence" and "Fresh Start Accounting" footnotes for more information.

Revenue Recognition—Revenues are predominantly derived from the sale of produced oil, NGLs and natural gas. The Company accounts for revenues in accordance with FASB ASC Topic 606 – *Revenue from Contracts with Customers* ("ASC 606"), and thus oil and gas revenues are recognized at the point in time at which the Company's performance obligation to deliver the product is met and control is transferred to the customer. The Company has determined that its contracts for the sale of crude oil, unprocessed natural gas, residue gas and NGLs contain monthly performance obligations to deliver product at locations specified in the contract. Control is transferred at the delivery location, at which point the performance obligation has been satisfied and revenue is recognized. Fees included in the contract that are incurred prior to control transfer are classified as transportation, gathering, compression and other, and fees incurred after control transfers are included as a reduction to the transaction price. The transaction price at which revenue is recognized consists entirely of variable consideration based on quoted market prices less various fees and the quantity of volumes delivered.

Payments for product sales are received one to three months after delivery. At the end of each month when the performance obligation is satisfied and the amount of production delivered and the price received can be reasonably estimated, amounts due from customers are accrued in accounts receivable trade, net in the consolidated balance sheets.

The Company has elected to utilize the practical expedient in ASC 606 that states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company's contracts, each monthly delivery of product represents a separate performance obligation, therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Taxes collected and remitted to governmental agencies on behalf of customers are not included in revenues or costs and expenses.

General and Administrative Expenses—General and administrative expenses are reported net of reimbursements of overhead costs that are allocated to the working interest owners that participate in oil and gas properties operated by Whiting.

Stock-based Compensation Expense—The Company has a share-based employee compensation plan that provides for the issuance of various types of stock-based awards, including shares of restricted stock, restricted stock units, performance shares, performance share units and stock options, to employees and non-employee directors. The Company determines compensation expense for share-settled awards granted under these plans based on the grant date fair value, and such expense is recognized on a straight-line basis over the requisite service period of the award. The Company determines compensation expense for cash-settled awards granted under these plans based on the fair value of such awards at the end of each reporting period. Cash-settled awards are recorded as a liability in the consolidated balance sheets, and gains and losses from changes in fair value are recognized immediately in earnings. The Company accounts for forfeitures of share-based awards as they occur. Refer to the "Stock-Based Compensation" footnote for further information.

401(k) Plan—The Company has a defined contribution retirement plan for all employees. The plan is funded by employee contributions and discretionary Company contributions. The Company's contributions for 2021, the 2020 Successor Period, the 2020 Predecessor Period and the year ended December 31, 2019 (Predecessor) were $3 million, $1 million, $4 million and $7 million, respectively. Non-executive employees become 100% vested in employer contributions immediately. Executives vest in employer contributions at 20% per year of completed service up to five years.

Income Taxes—Income taxes are recognized based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are accounted for using the liability method. Under this method, deferred tax assets and liabilities are determined by applying the enacted statutory tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the Company's financial statements. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is established when it is more likely than not that some portion of the benefit from deferred tax assets will not be realized. The Company's uncertain tax positions must meet a more-likely-than-not realization threshold to be recognized, and any potential accrued interest and penalties related to unrecognized tax benefits are recognized within income tax expense.

Earnings Per Share—Basic earnings per common share is calculated by dividing net income by the weighted average number of common shares outstanding during each period. Diluted earnings per common share is calculated by dividing adjusted net income by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations for the Successor periods consist of unvested restricted and performance stock units, outstanding warrants and contingently issuable shares related to settlement of outstanding claims related to the Chapter 11 Cases, all using the treasury stock method. Potentially dilutive securities for the diluted earnings per share calculations for the Predecessor periods consist of unvested restricted and performance stock awards and units, stock options and contingently issuable shares of convertible debt to be settled in cash, all using the treasury stock method. When a loss from continuing operations exists, all dilutive securities and potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share.

Industry Segment and Geographic Information—The Company has evaluated how it is organized and managed and has identified only one operating segment, which is the exploration and production of crude oil, NGLs and natural gas. The Company considers its gathering, processing and marketing functions as ancillary to its oil and gas producing activities. All of the Company's operations and assets are located in the United States, and substantially all of its revenues are attributable to United States customers.

Concentration of Credit Risk—Whiting is exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy related industries. The creditworthiness of customers and other counterparties is subject to continuing review. The following tables present the percentages by purchaser that accounted for 10% or more of the Company's total oil, NGL and natural gas sales for the periods presented.

Year Ended December 31, 2021	
Shell Trading (US) Company	23 %
Marathon Oil Company	11 %

Year Ended December 31, 2020	
Shell Trading (US) Company	14 %
Tesoro Crude Oil Co	13 %

Year Ended December 31, 2019	
Tesoro Crude Oil Co	14 %
Philips 66 Company	12 %

Commodity derivative contracts held by the Company are with nine counterparties, all of which are participants in Whiting's credit facility and all of which have investment-grade ratings from Moody's and Standard & Poor's. As of December 31, 2021, outstanding derivative contracts with JP Morgan Chase Bank, Wells Fargo Bank, N.A., Capital One, N.A and Canadian Imperial Bank of Commerce represented 30%, 25%, 10% and 10%, respectively, of total volumes hedged.

2. CHAPTER 11 EMERGENCE

Plan of Reorganization under Chapter 11 of the Bankruptcy Code—On April 1, 2020, the Debtors commenced the Chapter 11 Cases as described in the "Summary of Significant Accounting Policies" footnote above. On April 23, 2020, the Debtors entered into a restructuring support agreement with certain holders of the Company's senior notes to support a restructuring in accordance with the terms set forth in the Plan. On August 14, 2020, the Bankruptcy Court confirmed the Plan. On September 1, 2020 the Debtors satisfied all conditions required for Plan effectiveness and emerged from the Chapter 11 Cases.

On the Emergence Date and pursuant to the Plan:

(1) The Company amended and restated its certificate of incorporation and bylaws.

(2) The Company constituted a new Successor Board.

(3) The Company appointed a new Chief Executive Officer and a new Chief Financial Officer.

(4) The Company issued:

- 36,817,630 shares of the Successor's common stock pro rata to holders of the Predecessor's senior notes,
- 1,233,495 shares of the Successor's common stock pro rata to holders of the Predecessor's common stock,
- 4,837,387 Series A Warrants to purchase the same number of shares of the Successor's common stock pro rata to holders of the Predecessor's common stock and
- 2,418,840 Series B Warrants to purchase the same number of shares of the Successor's common stock pro rata to holders of the Predecessor's common stock.

The Company also reserved 3,070,201 shares of the Successor's common stock for potential future distribution to certain general unsecured claimants whose claim values were pending resolution in the Bankruptcy Court. In February 2021, the Company issued 948,897 shares out of this reserve to a general unsecured claimant in full settlement of such claimant's claims pending before the Bankruptcy Court and for rejection damages relating to an executory contract. Any remaining reserved shares that are not distributed to resolve pending claims will be cancelled. In addition, 4,035,885 shares were reserved for distribution under the Company's 2020 equity incentive plan, as further detailed in the "Stock-Based Compensation" footnote below.

(5) Whiting Petroleum Corporation, as parent guarantor, and Whiting Oil and Gas, as borrower, entered into the Credit Agreement with a syndicate of banks with initial aggregate commitments in the amount of $750 million, with the ability to increase the aggregate commitments by up to an additional $750 million, subject to certain conditions. Refer to the "Long-Term Debt" footnote for more information on the Credit Agreement. The Company utilized borrowings from the Credit Agreement and cash on hand to repay all borrowings and accrued interest outstanding on its pre-emergence credit facility (the "Predecessor Credit Agreement") as of the Emergence Date, which terminated on that date.

(6) The holders of trade claims, administrative expense claims, other secured claims and other priority claims received payment in full in cash upon emergence or through the ordinary course of business after the Emergence Date.

Executory Contracts—Subject to certain exceptions, under the Bankruptcy Code the Debtors were entitled to assume, assign or reject certain executory contracts and unexpired leases subject to the approval of the Bankruptcy Court and fulfillment of certain other conditions. Generally, the rejection of an executory contract or unexpired lease was treated as a pre-petition breach of such contract and, subject to certain exceptions, relieved the Debtors from performing future obligations under such contract but entitled the counterparty or lessor to a pre-petition general unsecured claim for damages caused by such deemed breach. Alternatively, the assumption of an executory contract or unexpired lease required the Debtors to cure existing monetary defaults under such executory contract or unexpired lease, if any. Accordingly, any description of an executory contract or unexpired lease with the Debtors in this document, including where applicable quantification of the Company's obligations under such executory or unexpired lease of the Debtors, is qualified by any overriding rejection rights the Company has under the Bankruptcy Code unless an order settling the claims has been issued by the Bankruptcy Court. Further, nothing herein is or shall be deemed an admission with respect to any claim amounts or calculations arising from the rejection of any executory contract or unexpired lease and the Debtors expressly reserve all of their rights in that regard. Refer to the "Commitments and Contingencies" footnote for more information on potential future rejection damages related to general unsecured claims.

Interest Expense—The Company discontinued recording interest on its senior notes as of the Petition Date. The contractual interest expense not accrued in the consolidated statements of operations was approximately $57 million for the period from the Petition Date through the Emergence Date.

Claims Resolution Process—Pursuant to the Plan, the Debtors have the sole authority to (1) file and prosecute objections to claims asserted by third parties and governmental entities and (2) settle, compromise, withdraw, litigate to judgment or otherwise resolve objections to such claims. The claims resolutions process is ongoing and certain of these claims remain subject to the jurisdiction of the Bankruptcy Court.

3. FRESH START ACCOUNTING

Fresh Start—In connection with the Company's emergence from bankruptcy and in accordance with ASC 852, the Company qualified for and adopted fresh start accounting on the Emergence Date. The Company was required to adopt fresh start accounting because (i) the holders of existing voting shares of the Predecessor received less than 50% of the voting shares of the Successor and (ii) the reorganization value of the Company's assets immediately prior to confirmation of the Plan was less than the total of post-petition liabilities and allowed claims.

In accordance with ASC 852, with the application of fresh start accounting, the Company allocated its reorganization value to its individual assets based on their estimated fair values in conformity with ASC 820 and FASB ASC Topic 805 – *Business Combinations* ("ASC 805"). The reorganization value represents the fair value of the Successor's assets before considering certain liabilities and is intended to represent the approximate amount a willing buyer would pay for the Company's assets immediately after reorganization.

Reorganization Value—As set forth in the Plan and related disclosure statement, the enterprise value of the Successor was estimated to be between $1.35 billion and $1.75 billion. At the Emergence Date, the Successor's estimated enterprise value was $1.59 billion before the consideration of cash and cash equivalents on hand, which falls slightly above the midpoint of this range. The enterprise value was derived primarily from an independent valuation using an income approach to derive the fair value of the Company's assets as of the fresh start reporting date of September 1, 2020.

The Company’s principal assets are its oil and natural gas properties. The fair value of proved reserves was estimated using an income approach, which was based on the anticipated future cash flows associated with those proved reserves, risked by reserve category and discounted using a weighted average cost of capital rate of 14%. The proved reserve locations included in this analysis were limited to wells included in the Company's five-year development plan. Future prices for the income approach were based on forward strip price curves (adjusted for basis differentials). The fair value of the Company’s unproved reserves was estimated using a combination of income and market approaches. Refer to further discussion below in “Fresh Start Accounting Adjustments.”

The following table reconciles the Company’s enterprise value to the implied value of the Successor’s common stock as of September 1, 2020 (in thousands):

Enterprise value	$	1,591,887
Plus: Cash and cash equivalents		22,657
Less: Fair value of debt		(425,328)
Implied value of Successor common stock	$	1,189,216

The following table reconciles the Company’s enterprise value to its reorganization value as of September 1, 2020 (in thousands):

Enterprise value	$	1,591,887
Plus:		
Cash and cash equivalents		22,657
Accounts payable trade		56,432
Revenues and royalties payable		145,506
Other current liabilities		143,790
Asset retirement obligations		121,343
Operating lease obligations		17,839
Deferred income taxes		14,501
Other long-term liabilities		28,773
Reorganization value	$	2,142,728

Although the Company believes the assumptions and estimates used to develop enterprise value and reorganization value are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. The assumptions used in estimating these values are inherently uncertain and require judgment. Refer to the caption “Fresh Start Adjustments” below for additional information regarding assumptions used in the valuation of the Company’s significant assets and liabilities.

Condensed Consolidated Balance Sheet at Emergence (in thousands)—The adjustments set forth in the following condensed consolidated balance sheet as of September 1, 2020 reflect the consummation of transactions contemplated by the Plan (the “Reorganization Adjustments”) and the fair value adjustments as a result of applying fresh start accounting (the “Fresh Start Adjustments”). The explanatory notes highlight methods used to determine fair values or other amounts of the corresponding assets or liabilities, as well as significant assumptions.

	As of September 1, 2020			
	Predecessor	Reorganization Adjustments	Fresh Start Adjustments	Successor
ASSETS				
Current assets:				
Cash and cash equivalents	$ 547,354	$ (524,697)(a)	$ -	$ 22,657
Restricted cash	28,955	(2,205)(b)	-	26,750
Accounts receivable trade, net	136,881	-	81 (o)	136,962
Prepaid expenses and other	18,722	231 (c)	2,260 (p)	21,213
Total current assets	731,912	(526,671)	2,341	207,582
Property and equipment:				
Oil and gas properties, successful efforts method	4,885,013	-	(3,058,899)(q)	1,826,114
Other property and equipment	159,866	(909)(d)	(87,642)(o)(r)	71,315
Total property and equipment	5,044,879	(909)	(3,146,541)	1,897,429
Less accumulated depreciation, depletion and amortization	(2,085,266)	-	2,085,266 (o)(q)(r)	-
Total property and equipment, net	2,959,613	(909)	(1,061,275)	1,897,429
Debt issuance costs	1,834	10,950 (e)	-	12,784
Other long-term assets	37,010	(8,760)(d)	(3,317)(o)(s)	24,933
TOTAL ASSETS	$ 3,730,369	$ (525,390)	$ (1,062,251)	$2,142,728
LIABILITIES AND EQUITY (DEFICIT)				
Current liabilities:				
Current portion of long-term debt	$ 912,259	$ (912,259)(f)	$ -	$ -
Accounts payable trade	47,168	9,264 (g)(h)	-	56,432
Revenues and royalties payable	145,506	-	-	145,506
Accrued capital expenditures	14,037	1,305 (g)	-	15,342
Accrued liabilities and other	46,327	21,942 (g)(i)	(6,529)(o)(t)	61,740
Accrued lease operating expenses	25,344	1,394 (g)	-	26,738
Accrued interest	3,459	(3,332)(g)(j)	(127)(o)	-
Taxes payable	13,972	-	-	13,972
Derivative liabilities	25,998	-	-	25,998
Total current liabilities	1,234,070	(881,686)	(6,656)	345,728
Long-term debt	-	425,328 (k)	-	425,328
Asset retirement obligations	150,925	-	(29,582)(u)	121,343
Operating lease obligations	-	17,652 (d)(g)	187 (o)	17,839
Deferred income taxes	69,847	-	(55,346)(v)	14,501
Other long-term liabilities	18,160	11,071 (g)	(458)(o)(t)	28,773
Total liabilities not subject to compromise	1,473,002	(427,635)	(91,855)	953,512
Liabilities subject to compromise	2,526,925	(2,526,925)(g)	-	-
Total liabilities	3,999,927	(2,954,560)	(91,855)	953,512
Commitments and contingencies				
Equity (deficit):				
Predecessor common stock	92	(92)(l)	-	-
Successor common stock	-	38 (m)	-	38
Predecessor additional paid-in capital	6,410,410	(6,410,410)(l)	-	-
Successor additional paid-in capital	-	1,189,178 (m)	-	1,189,178
Accumulated earnings (deficit)	(6,680,060)	7,650,456 (n)	(970,396)(w)	-
Total equity (deficit)	(269,558)	2,429,170	(970,396)	1,189,216
TOTAL LIABILITIES AND EQUITY (DEFICIT)	$ 3,730,369	$ (525,390)	$ (1,062,251)	$2,142,728

Reorganization Adjustments

(a) The table below reflects the sources and uses of cash on the Emergence Date pursuant to the terms of the Plan (in thousands):

Sources:		
Release of restricted cash upon bankruptcy emergence	$	28,205
Borrowings under the Credit Agreement		425,328
Total sources of cash		453,533
Uses:		
Payment of outstanding borrowings under the Predecessor Credit Agreement		(912,259)
Payment of accrued interest on the Predecessor Credit Agreement		(3,437)
Payment of debt issuance costs related to the Credit Agreement		(10,950)
Funding of the Professional Fee Escrow Account		(26,000)
Payment of professional fees upon emergence		(14,470)
Payment of contract cure amounts		(11,114)
Total uses of cash		(978,230)
Net uses of cash	$	(524,697)

(b) The table below reflects the net reclassification of cash balances to and from restricted cash on the Emergence Date pursuant to terms of the Plan (in thousands):

Funding of the Professional Fee Escrow Account	$	26,000
Release of restricted cash upon bankruptcy emergence [1]		(28,205)
Net reclassifications from restricted cash	$	(2,205)

(1) Includes $23 million of funds related to derivative termination settlements that were directed by the counterparty to be held in a segregated account until the Company emerged from bankruptcy, as well as $5 million of amounts set aside as adequate assurance for utility providers that were restricted until emergence.

(c) Reflects the payment of professional fee retainers upon emergence.

(d) The Company amended a corporate office lease agreement and terminated the lease of certain floors within that agreement, which amendment was effective upon emergence from the Chapter 11 Cases. As a result of the lease modification and terminations, the Company reduced the associated right-of-use assets and operating lease obligations by $10 million and $15 million, respectively, resulting in a $5 million gain on settlement of liabilities subject to compromise, which was recorded to reorganization items, net in the consolidated statements of operations. The corporate office lease was classified as an operating lease and the modification did not result in a change to the lease's classification. Additionally, $18 million of long-term operating lease obligations in liabilities subject to compromise were reinstated to be satisfied in the ordinary course of business.

(e) Represents $11 million of financing costs related to the Credit Agreement which were capitalized as debt issuance costs and will be amortized to interest expense through the maturity date of April 1, 2024.

(f) Reflects the payment in full of the borrowings outstanding under the Predecessor Credit Agreement on the Emergence Date.

(g) As part of the Plan, the Bankruptcy Court approved the settlement of certain claims reported within liabilities subject to compromise in the Company's consolidated balance sheet at their respective allowed claim amounts. The table below indicates the reinstatement or disposition of liabilities subject to compromise (in thousands):

Liabilities subject to compromise pre-emergence	$	2,526,925
Amounts reinstated on the Emergence Date:		
Accounts payable trade		(10,866)
Accrued capital expenditures		(1,305)
Accrued lease operating expenses		(1,394)
Accrued liabilities and other		(13,961)
Accrued interest		(105)
Operating lease obligations		(17,652)
Other long-term liabilities		(11,071)
Total liabilities reinstated		(56,354)
Less: Amounts settled per the Plan		
Issuance of common stock to general unsecured claim holders		(1,125,062)
Payment of contract cure amounts		(10,836)
Operating lease modification and terminations		(9,669)
Issuance of Successor common stock to holders of unvested cash-settled equity awards [1]		(64)
Total amounts settled		(1,145,631)
Gain on settlement of liabilities subject to compromise	$	1,324,940

(1) Holders of unvested cash-settled restricted stock awards were included as existing equity interests in the Plan and thus received Successor common stock on a pro rata basis based on the amount of unvested awards held. This amount represents the gain on the liability related to those awards, which was included in liabilities subject to compromise prior to emergence.

(h) Reflects the reinstatement of $11 million of accounts payable included in liabilities subject to compromise to be satisfied in the ordinary course of business, partially offset by $2 million of professional fees paid on the Emergence Date.

(i) Represents the accrual of success fees payable upon emergence as well as certain other expenses, the payment of certain professional fees that were accrued for prior to emergence and the reinstatement of certain accrued liabilities included in liabilities subject to compromise to be satisfied in the ordinary course of business, as detailed in the following table (in thousands):

Reinstatement of accrued expenses from liabilities subject to compromise	$	13,961
Recognition of success fee payable upon emergence		11,500
Other expenses accrued at emergence		3,315
Payment of certain professional fees accrued prior to emergence		(6,834)
Net impact to accrued liabilities and other	$	21,942

(j) Represents a $3 million payment of accrued interest on the Predecessor Credit Agreement and reinstated accrued interest that was included within liabilities subject to compromise to be satisfied in the ordinary course of business.

(k) Reflects borrowings drawn under the Credit Agreement upon emergence. Refer to the "Long-Term Debt" footnote for more information on the Credit Agreement.

(l) Pursuant to the terms of the Plan, on the Emergence Date, all Predecessor common stock interests were cancelled. As a result of the cancellation, the Company accelerated the recognition of $4 million in compensation expense related to the unrecognized portion of share-based compensation as of the Emergence Date, which was recorded to reorganization items, net in the consolidated statements of operations.

(m) Reflects the issuance of Successor equity, including the issuance of 38,051,125 shares of common stock at a par value of $0.001 per share and warrants to purchase 7,256,227 shares of common stock in exchange for claims against or interests in the Debtors pursuant to the Plan. Equity issued to each class of claims is detailed in the table below (in thousands):

Issuance of common stock to general unsecured claim holders	$	1,125,062
Issuance of common stock to Predecessor common stockholders and holders of unvested cash-settled equity awards		34,794
Issuance of warrants to Predecessor common stockholders and holders of unvested cash-settled equity awards		29,360
Fair value of Successor equity	$	1,189,216

(n) The table below reflects the cumulative impact of the reorganization adjustments discussed above (in thousands):

Gain on settlement of liabilities subject to compromise	$	1,324,940
Cancellation of Predecessor equity [1]		6,414,541
Fair value of equity issued to Predecessor common stockholders and holders of unvested cash-settled equity awards		(34,794)
Fair value of warrants issued to Predecessor common stockholders and holders of unvested cash-settled equity awards		(29,360)
Success fees incurred upon emergence		(17,303)
Acceleration of unvested stock-based compensation awards		(4,161)
Other expenses incurred upon emergence		(3,407)
Net impact on accumulated earnings (deficit)	$	7,650,456

(1) This value is reflective of Predecessor common stock, Predecessor additional paid in capital and the recognition of $4 million in compensation expense related to the unrecognized portion of share-based compensation.

Fresh Start Adjustments

(o) Reflects the adjustments to fair value made to operating and finance lease assets and liabilities. Upon adoption of fresh start accounting, the Company's remaining lease obligations were recalculated using the incremental borrowing rate applicable to the Company upon emergence and commensurate with the Successor's capital structure. The fair value adjustments related to leases are summarized in the table below (in thousands):

Lease Asset/Liability	Emergence Balance Sheet Classification		Fair Value Adjustment
Accounts receivable, net	Accounts receivable, net	$	81
Operating lease assets, net	Other long-term assets		(1,480)
Finance lease assets	Other property and equipment		(10,765)
Accumulated depreciation - finance leases	Less accumulated depreciation, depletion and amortization		15,099
Accrued interest - finance leases	Accrued interest		127
Short-term finance lease obligation	Accrued liabilities and other		(576)
Short-term operating lease obligation	Accrued liabilities and other		319
Long-term finance lease obligation	Other long-term liabilities		(1,174)
Long-term operating lease obligation	Operating lease obligations		(187)
		$	1,444

(p) Reflects the adjustment to fair value of the Company's oil in tank inventory based on market prices as of the Emergence Date.

(q) Reflects the adjustments to fair value of the Company's oil and natural gas properties and undeveloped properties, as well as the elimination of accumulated depletion, depreciation and amortization.

For purposes of estimating the fair value of the Company's proved oil and gas properties, an income approach was used which estimated the fair value based on the anticipated future cash flows associated with the Company's proved reserves, risked by reserve category and discounted using a weighted average cost of capital rate of 14%. The proved reserve locations included in this analysis were limited to wells included in the Company's five-year development plan. Future prices for the income approach were based on forward strip price curves (adjusted for basis differentials) as of the Emergence Date.

In estimating the fair value of the Company's unproved properties, a combination of income and market approaches were utilized. The income approach consistent with that utilized for proved properties was utilized for properties which had positive future cash flows associated with reserve locations that did not qualify as proved reserves. A market approach was used to value the remainder of the Company's unproved properties.

(r) Reflects the fair value adjustment to recognize the Company's land, buildings and other property, plant and equipment as of the Emergence Date based on the fair values of such land, buildings and other property, plant and equipment as well as the elimination of related historical depletion, depreciation and amortization balances. Land and buildings were valued using a market approach. Other property, plant and equipment were valued using a cost approach based on the current replacement costs of the assets, less depreciation based on the estimated economic useful lives of the assets and the age of the assets. The fair value adjustments consisted of a decrease of $16 million in land and buildings, a decrease of $61 million in other property, plant and equipment and a corresponding write-off of $66 million in accumulated depletion, depreciation and amortization.

(s) Reflects the adjustment to fair value of the Company's other long-term assets, including line fill and pipeline imbalances, based on the commodity market prices as of the Emergence Date, which resulted in a $2 million decrease to other long-term assets.

(t) Represents the write-off of a deferred gain balance associated with the Predecessor. The deferred gain does not relate to the Successor and therefore the unamortized balance was written off in full in the Predecessor's consolidated statements of operations. Of the total $9 million write off, $7 million related to the short-term portion of the deferred gain (included in accrued liabilities and other in the consolidated balance sheets at emergence) and $2 million related to the long-term portion (included in other long-term liabilities in the consolidated balance sheets at emergence).

(u) Reflects the adjustment to fair value of the Company's asset retirement obligations including using a credit-adjusted risk-free rate as of the Emergence Date.

(v) Reflects the adjustment to fair value of the Company's deferred tax liability related to Whiting Canadian Holding Company ULC's outside basis difference in its ownership of a portion of Whiting's U.S. assets obtained through the acquisition of Kodiak Oil and Gas Corporation in 2014.

(w) Reflects the cumulative impact of the fresh start adjustments discussed above.

Reorganization Items, Net—Any expenses, gains and losses that were realized or incurred between the Petition Date and the Emergence Date and as a direct result of the Chapter 11 Cases were recorded in reorganization items, net in the Company's consolidated statements of operations. The following table summarizes the components of reorganization items, net for the periods presented (in thousands):

	Successor	**Predecessor**
	Four Months Ended December 31, 2020	**Eight Months Ended August 31, 2020**
Legal and professional advisory fees	$ -	$ 57,170
Net gain on liabilities subject to compromise	-	(1,324,940)
Fresh start adjustments, net	-	1,025,742
Write-off of unamortized debt issuance costs and premium [1]	-	15,145
Other items, net	-	9,464
Total reorganization items, net	$ -	$ (217,419)

(1) As a result of the Chapter 11 Cases and the adoption of ASC 852, the Company wrote off all unamortized premium and issuance cost balances related to its senior notes on the Petition Date.

4. OIL AND GAS PROPERTIES

Net capitalized costs related to the Company’s oil and gas producing activities at December 31, 2021 and 2020 are as follows (in thousands):

	Successor	
	December 31, 2021	December 31, 2020
Proved oil and gas properties	$ 2,034,533	$ 1,701,163
Unproved leasehold costs	182,109	105,073
Wells and facilities in progress	58,266	6,365
Total oil and gas properties, successful efforts method	2,274,908	1,812,601
Accumulated depletion	(248,298)	(71,064)
Oil and gas properties, net	$ 2,026,610	$ 1,741,537

The following tables present impairment expense for unproved properties for the periods presented, which is reported in exploration and impairment expense in the consolidated statements of operations (in thousands):

	Successor		Predecessor	
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Year Ended December 31, 2019
Impairment expense for unproved properties	$ 3,093	$ 1,396	$ 12,566	$ 9,450

5. ACQUISITIONS AND DIVESTITURES

2021 Acquisitions and Divestitures

On September 14, 2021, the Company completed the acquisition of interests in oil and gas properties located in Mountrail County, North Dakota for an aggregate purchase price of $271 million (before closing adjustments). The revenue and earnings from these properties since the acquisition date are included in the Company’s consolidated financial statements for the year ended December 31, 2021. Pro forma revenue and earnings for the acquired properties are not material to the Company’s consolidated financial statements and have therefore not been presented.

The acquisition was accounted for as a business combination and was recorded using the acquisition method of accounting in accordance with ASC 805. The following table summarizes the preliminary allocation of the $268 million adjusted purchase price (which is still subject to post-closing adjustments) to the assets acquired and liabilities assumed in this acquisition based on their respective fair values at the acquisition date, which did not result in the recognition of goodwill or a bargain purchase gain. Refer to the “Fair Value Measurements” footnote for a detailed discussion of the fair value inputs used by the Company in determining the valuation of the significant assets acquired and liabilities assumed. As the purchase price is further adjusted for post-close adjustments and as the oil and gas property valuation is completed, the final purchase price allocation may result in a different allocation than what is presented in the table below (in thousands):

Cash consideration	$	270,800
Purchase price adjustments		(2,553)
Adjusted purchase price	$	268,247
Fair Value of Assets Acquired:		
Prepaid expenses and other	$	730
Oil and gas properties, successful efforts method:		
Proved oil and gas properties		167,435
Unproved leasehold costs		103,397
Total fair value of assets acquired		271,562
Fair Value of Liabilities Assumed:		
Asset retirement obligations		2,242
Revenue and royalties payable		1,073
Total fair value of liabilities assumed		3,315
Total fair value of assets acquired and liabilities assumed	$	268,247

On September 23, 2021, the Company completed the sale of all of its interests in producing assets and undeveloped acreage, including the associated midstream assets, of its Redtail field located in the Denver-Julesburg Basin of Weld County, Colorado for aggregate net sales proceeds of $171 million. The sale was effective June 1, 2021 and resulted in a pre-tax gain on sale of $86 million. The divestiture remains subject to a final settlement between Whiting and the buyer of the properties, which could impact the ultimate proceeds received and the gain recognized as a result of the transaction. The Company used the net proceeds from the sale to repay a portion of the borrowings outstanding under the Credit Agreement. This transaction included the removal of approximately $20 million in asset retirement obligations as well as certain finance leases for a pipeline and vehicles, which resulted in the termination of approximately $16 million of finance lease right-of-use assets, $3 million of accumulated depreciation and $12 million of long-term finance lease obligations.

On December 16, 2021, the Company completed the acquisition of additional interests in oil and gas properties located in Mountrail County, North Dakota for an aggregate purchase price of $32 million (before closing adjustments). The acquisition was accounted for as a business combination and was recorded using the acquisition method of accounting in accordance with ASC 805. The preliminary allocation of the $32 million purchase price resulted in $31 million of proved oil and gas properties acquired, $1 million of unproved leasehold costs acquired and $1 million of asset retirement obligations assumed. As the purchase price is further adjusted for post-close adjustments and as the oil and gas property valuation is completed, the final purchase price allocation may result in a different allocation.

2020 Acquisitions and Divestitures

On January 9, 2020, the Predecessor completed the divestiture of its interests in 30 non-operated, producing oil and gas wells and related undeveloped acreage located in McKenzie County, North Dakota for aggregate sales proceeds of $25 million (before closing adjustments).

There were no significant acquisitions during the year ended December 31, 2020.

2019 Acquisitions and Divestitures

On July 29, 2019, the Predecessor completed the divestiture of its interests in 137 non-operated, producing oil and gas wells located in the McKenzie, Mountrail and Williams counties of North Dakota for aggregate sales proceeds of $27 million (before closing adjustments).

On August 15, 2019, the Predecessor completed the divestiture of its interests in 58 non-operated, producing oil and gas wells located in Richland County, Montana and Mountrail and Williams counties of North Dakota for aggregate sales proceeds of $26 million (before closing adjustments).

There were no significant acquisitions during the year ended December 31, 2019.

6. LEASES

The Company has operating and finance leases for corporate and field offices, equipment, pipeline and midstream facilities and automobiles. Right-of-use ("ROU") assets and liabilities associated with these leases are recognized at the lease commencement date based on the present value of the lease payments over the lease term. ROU assets represent the Company's right to use an underlying asset for the lease term, and lease liabilities represent the Company's obligation to make lease payments.

Supplemental balance sheet information for the Company's leases as of December 31, 2021 and 2020 consisted of the following (in thousands):

		Successor	
Leases	**Balance Sheet Classification**	**December 31, 2021**	**December 31, 2020**
Operating Leases			
Operating lease ROU assets	Other long-term assets	$ 21,962	$ 21,962
Accumulated depreciation	Other long-term assets	(4,499)	(1,096)
Operating lease ROU assets, net		$ 17,463	$ 20,866
Short-term operating lease obligations	Accrued liabilities and other	$ 3,086	$ 4,031
Long-term operating lease obligations	Operating lease obligations	14,710	17,415
Total operating lease obligations		$ 17,796	$ 21,446
Finance Leases			
Finance lease ROU assets	Other property and equipment	$ 4,023	$ 19,706
Accumulated depreciation	Accumulated depreciation, depletion and amortization	(2,025)	(1,797)
Finance lease ROU assets, net		$ 1,998	$ 17,909
Short-term finance lease obligations	Accrued liabilities and other	$ 1,321	$ 4,830
Long-term finance lease obligations	Other long-term liabilities	721	13,138
Total finance lease obligations		$ 2,042	$ 17,968

The Company's leases have remaining terms of up to 10 years. Most of the Company's leases do not state or imply a discount rate. Accordingly, the Company uses its incremental borrowing rate based on information available at lease commencement to determine the present value of the lease payments. Information regarding the Company's lease terms and discount rates as of December 31, 2021 and 2020 is as follows:

	Successor	
	December 31, 2021	**December 31, 2020**
Weighted Average Remaining Lease Term		
Operating leases	7 years	7 years
Finance leases	2 years	4 years
Weighted Average Discount Rate		
Operating leases	4.4%	4.4%
Finance leases	4.1%	4.2%

Operating lease cost is recognized on a straight-line basis over the lease term. Finance lease cost is recognized based on the effective interest method for the lease liability and straight-line amortization of the ROU asset, resulting in more cost being recognized in earlier lease periods. All payments for short-term leases, including leases with a term of one month or less, are recognized in income or capitalized to the cost of oil and gas properties on a straight-line basis over the lease term. Additionally, any variable payments, which are generally related to the corresponding utilization of the asset, are recognized in the period in which the obligation was incurred. Lease cost for the periods presented consisted of the following (in thousands):

	Successor		Predecessor	
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Year Ended December 31, 2019
Operating lease cost	$ 4,251	$ 1,462	$ 4,691	$ 11,512
Finance lease cost:				
Amortization of ROU assets	$ 4,202	$ 1,842	$ 3,347	$ 5,661
Interest on lease liabilities	513	260	1,131	1,996
Total finance lease cost	$ 4,715	$ 2,102	$ 4,478	$ 7,657
Short-term lease payments	$ 224,711	$ 26,430	$ 164,815	$ 676,850
Variable lease payments	$ 10,637	$ 99	$ 23,307	$ 31,812

Total lease cost represents the total financial obligations of the Company, a portion of which has been or will be reimbursed by the Company's working interest partners. Lease cost is included in various line items in the consolidated statements of operations or capitalized to oil and gas properties and is recorded at the Company's net working interest.

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

	Successor		Predecessor	
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from operating leases	$ 4,500	$ 2,174	$ 5,813	$ 11,978
Operating cash flows from finance leases	$ 536	$ 197	$ 1,156	$ 2,006
Financing cash flows from finance leases	$ 4,020	$ 1,773	$ 3,198	$ 5,140
ROU assets obtained in exchange for new operating lease obligations	$ -	$ 6,368	$ 3,252	$ 18,658
ROU assets obtained in exchange for new finance lease obligations	$ 357	$ -	$ 170	$ 4,158

The Company's lease obligations as of December 31, 2021 will mature as follows (in thousands):

Year ending December 31,	Operating Leases	Finance Leases
2022	$ 3,572	$ 1,378
2023	3,255	637
2024	2,950	76
2025	1,904	23
2026	1,940	4
Remaining	7,356	-
Total lease payments	20,977	2,118
Less imputed interest	(3,181)	(76)
Total discounted lease payments	$ 17,796	$ 2,042

7. LONG-TERM DEBT

Long-term debt, consisting entirely of borrowings outstanding under the Credit Agreement, totaled $360 million at December 31, 2020. At December 31, 2021, the Company had no long-term debt.

Credit Agreement (Successor)

On the Emergence Date, Whiting Petroleum Corporation, as parent guarantor, and Whiting Oil and Gas, as borrower, entered into the Credit Agreement, a reserves-based credit facility, with a syndicate of banks. As of December 31, 2021, the Credit Agreement had a borrowing base and aggregate commitments of $750 million. As of December 31, 2021, the Company had no borrowings outstanding under the Credit Agreement with $749 million of available borrowing capacity, which was net of $1 million in letters of credit outstanding. On September 15, 2021, the Company entered into an amendment to its existing Credit Agreement in connection with the October 1, 2021 regular borrowing base redetermination that (i) reaffirmed the $750 million borrowing base with such redetermination contemplating the closing of the Company's recent divestiture described in the "Acquisitions and Divestitures" footnote, (ii) reduced the Company's requirement to maintain commodity hedges covering its projected production for the succeeding twelve months from a minimum of 65% to a minimum of 50% and (iii) eliminated the Company's requirement to maintain commodity hedges covering its projected production for the second succeeding twelve-month period, provided that the Company maintains a consolidated net leverage ratio of less than 1.0 to 1.0 as of the last day of any fiscal quarter. If the Company's consolidated net leverage ratio equals or exceeds 1.0 to 1.0 as of the last day of any fiscal quarter, the Company will also be required to hedge 35% of its projected production for the second succeeding twelve-month period.

The borrowing base under the Credit Agreement is determined at the discretion of the lenders, based on the collateral value of the Company's proved reserves that have been mortgaged to such lenders, and is subject to regular redeterminations on April 1 and October 1 of each year, as well as special redeterminations described in the Credit Agreement, in each case which may increase or decrease the amount of the borrowing base. Additionally, the Company can increase the aggregate commitments by up to an additional $750 million, subject to certain conditions.

Up to $50 million of the borrowing base may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company. As of December 31, 2021, $49 million was available for additional letters of credit under the Credit Agreement.

The Credit Agreement provides for interest only payments until maturity on April 1, 2024, when the agreement terminates and any outstanding borrowings are due. In addition, the Credit Agreement provides for certain mandatory prepayments, including a provision pursuant to which, if the Company's cash balances are in excess of approximately $75 million during any given week, such excess must be utilized to repay any outstanding borrowings under the Credit Agreement. Interest under the Credit Agreement accrues at the Company's option at either (i) a base rate for a base rate loan plus a margin between 1.75% and 2.75% based on the ratio of outstanding borrowings and letters of credit to the lower of the current borrowing base or total commitments, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.5% per annum, or an adjusted LIBOR plus 1.0% per annum, or (ii) an adjusted LIBOR for a eurodollar loan plus a margin between 2.75% and 3.75% based on the ratio of outstanding borrowings and letters of credit to the lower of the current borrowing base or total commitments. The Credit Agreement also provides that the administrative agent and the Company have the ability to amend the LIBOR rate with a benchmark replacement rate, which may be a SOFR-based rate, if LIBOR borrowings become unavailable. Additionally, the Company incurs commitment fees of 0.5% on the unused portion of the aggregate commitments of the lenders under the Credit Agreement, which are included as a component of interest expense.

The Credit Agreement contains restrictive covenants that may limit the Company's ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of its lenders. The Credit Agreement also restricts the Company's ability to make any dividend payments or distributions of cash on its common stock except to the extent that the Company has distributable free cash flow and (i) has at least 20% of available borrowing capacity, (ii) has a consolidated net leverage ratio of less than or equal to 2.0 to 1.0, (iii) does not have a borrowing base deficiency and (iv) is not in default under the Credit Agreement. These restrictions apply to all of the Company's restricted subsidiaries and are calculated in accordance with definitions contained in the Credit Agreement. The amended Credit Agreement requires the Company, as of the last day of any quarter, to maintain commodity hedges covering a minimum of 50% of its projected production for the succeeding twelve months, as reflected in the reserves report most recently provided by the Company to the lenders under the Credit Agreement. If the Company's consolidated net leverage ratio equals or exceeds 1.0 to 1.0 as of the last day of any fiscal quarter, the Company will also be required to hedge 35% of its projected production for the second succeeding twelve months. The Company is also limited to hedging a maximum of 85% of its production from proved reserves. The Credit Agreement requires the Company to maintain the following ratios (as defined in the Credit Agreement): (i) a consolidated current assets to consolidated current liabilities ratio of not less than 1.0 to 1.0 and (ii) a total debt to last four quarters' EBITDAX ratio of not greater than 3.5 to 1.0. As of December 31, 2021, the Company was in compliance with the covenants under the Credit Agreement.

The obligations of Whiting Oil and Gas under the Credit Agreement are secured by a first lien on substantially all of the Company's and certain of its subsidiaries' properties. The Company has also guaranteed the obligations of Whiting Oil and Gas under the Credit Agreement and has pledged the stock of certain of its subsidiaries as security for its guarantee.

Predecessor Senior Notes and Convertible Senior Notes

Prior to the Emergence Date, the Company had outstanding notes consisting of $774 million of 5.75% Senior Notes due 2021 (the "2021 Senior Notes"), $408 million of 6.25% Senior Notes due 2023 and $1.0 billion of 6.625% Senior Notes due 2026 (collectively with the 2021 Senior Notes, the "Senior Notes") and $187 million of 1.25% Convertible Senior Notes due 2020 (the "Convertible Senior Notes"). On the Emergence Date, through implementation of the Plan, all outstanding obligations under the Senior Notes and the Convertible Senior Notes were cancelled and 36,817,630 shares of Successor common stock were issued to the holders of those cancelled notes. In addition, the remaining unamortized debt issuance costs and debt premium were written off to reorganization items, net in the consolidated statements of operations. Refer to the "Chapter 11 Emergence" and "Fresh Start Accounting" footnotes for more information.

In September 2019, the Predecessor paid $299 million to complete a cash tender offer for $300 million aggregate principal amount of the Convertible Senior Notes, which payment consisted of the 99.0% purchase price plus all accrued and unpaid interest on the notes, which were allocated to the liability and equity components based on their relative fair values. The Company financed the tender offer with borrowings under the Predecessor Credit Agreement. As a result of the tender offer, the Company recognized a $4 million gain on extinguishment of debt, which was net of a $7 million charge for the non-cash write-off of unamortized debt issuance costs and debt discount and a $1 million charge for transaction costs.

In March 2020, the Company paid $53 million to repurchase $73 million aggregate principal amount of the Convertible Senior Notes, which payment consisted of the average 72.5% purchase price plus all accrued and unpaid interest on the notes, which were allocated to the liability and equity components based on their relative fair values. The Company financed the repurchases with borrowings under the Predecessor Credit Agreement. As a result of these repurchases, the Company recognized a $23 million gain on extinguishment of debt during the 2020 Predecessor Period, which was net of a $0.2 million charge for the non-cash write-off of unamortized debt issuance costs and debt discount. In addition, the Company recorded a $3 million reduction to the equity component of the Convertible Senior Notes. There was no deferred tax impact associated with this reduction due to the full valuation allowance in effect as of March 31, 2020.

Interest expense recognized on the Convertible Senior Notes related to the stated interest rate and amortization of the debt discount totaled $1 million and $26 million for the 2020 Predecessor Period and the year ended December 31, 2019, respectively.

Repurchases of 2021 Senior Notes. In September and October 2019, the Predecessor paid $96 million to repurchase $100 million aggregate principal amount of the 2021 Senior Notes, which payment consisted of the average 95.279% purchase price plus all accrued and unpaid interest on the notes. The Company financed the repurchases with borrowings under the Predecessor Credit Agreement. As a result of the repurchases, the Company recognized a $1 million gain on extinguishment of debt during the year ended December 31, 2019, which included a non-cash charge for the acceleration of unamortized debt issuance costs and debt premium on the notes.

8. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations represent the present value of estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration in accordance with applicable local, state and federal laws and the terms of the Company's lease agreements. The current portions as of December 31, 2021 and 2020 were $10 million and $6 million, respectively, and have been included in accrued liabilities and other in the consolidated balance sheets. The following table provides a reconciliation of the Company's asset retirement obligations for the periods presented (in thousands):

Asset retirement obligation at January 1, 2020 (Predecessor)	$	134,893
Additional liability incurred		76
Revisions to estimated cash flows		56,702
Accretion expense		8,199
Obligations on sold properties		(693)
Liabilities settled [(1)]		(42,854)
Asset retirement obligation at August 31, 2020 (Predecessor)		156,323
Fresh start adjustment [(2)]		(29,582)
Asset retirement obligation at September 1, 2020 (Successor)		126,741
Additional liability incurred		20
Revisions to estimated cash flows		(30,623)
Accretion expense		3,801
Liabilities settled		(1,809)
Asset retirement obligation at December 31, 2020 (Successor)		98,130
Additional liability incurred or assumed		4,348
Revisions to estimated cash flows		26,605
Accretion expense		8,237
Obligations on sold properties		(29,251)
Liabilities settled		(4,002)
Asset retirement obligation at December 31, 2021 (Successor)	$	104,067

(1) A portion of the Predecessor's asset retirement obligations related to a contractual obligation to remove certain offshore facilities in California. The Company included the related contract in its schedule of rejected contracts as part of the Plan, and the related amounts of the obligations were included in liabilities subject to compromise in the consolidated balance sheets of the Predecessor as of August 31, 2020. A final ruling from the Bankruptcy Court on the rejection of this contract has not yet been issued. Refer to the "Fresh Start Accounting" and "Commitments and Contingencies" footnotes under the heading "Chapter 11 Cases—*Arguello Inc. and Freeport-McMoRan Oil & Gas LLC*" for additional information.

(2) Refer to the "Fresh Start Accounting" footnote for more information on fresh start adjustments.

9. DERIVATIVE FINANCIAL INSTRUMENTS

The Company is exposed to certain risks relating to its ongoing business operations, and it uses derivative instruments to manage its commodity price risk.

Commodity Derivative Contracts—Historically, prices received for crude oil, natural gas and natural gas liquids production have been volatile because of supply and demand factors, worldwide political factors, general economic conditions and seasonal weather patterns. Whiting primarily enters into derivative contracts such as crude oil, natural gas and NGL swaps, collars, basis swaps and differential swaps to achieve a more predictable cash flow by reducing its exposure to commodity price volatility, thereby ensuring adequate funding for the Company's capital programs and facilitating the management of returns on drilling programs and acquisitions. The Company also enters into derivative contracts to maintain its compliance with certain minimum hedging requirements contained in the Credit Agreement. Refer to the "Long-Term Debt" footnote for a detailed discussion of the minimum and maximum hedging requirements of the Credit Agreement. The Company does not enter into derivative contracts for speculative or trading purposes.

Swaps, Collars, Basis Swaps and Differential Swaps. Swaps establish a fixed price for anticipated future oil, gas or NGL production, while collars are designed to establish floor and ceiling prices on anticipated future production. Basis and differential swaps mitigate risk associated with anticipated future production by establishing a fixed differential between NYMEX prices and the index price referenced in the contract. While the use of these derivative instruments limits the downside risk of adverse price movements, it may also limit future income from favorable price movements.

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The table below details the Successor's swap and collar derivatives entered into to hedge forecasted crude oil, natural gas and NGL production revenues as of December 31, 2021.

					Weighted Average		
Settlement Period	**Index**	**Derivative Instrument**	**Total Volumes**	**Units**	**Swap Price**	**Floor**	**Ceiling**
Crude Oil							
2022	NYMEX WTI	Fixed Price Swaps	2,275,000	Bbl	$69.29	-	-
2022	NYMEX WTI	Two-way Collars	11,204,000	Bbl	-	$47.07	$57.59
Q1-Q3 2023	NYMEX WTI	Two-way Collars	3,443,500	Bbl	-	$46.75	$58.87
		Total	16,922,500				
Natural Gas							
2022	NYMEX Henry Hub	Fixed Price Swaps	8,009,000	MMBtu	$3.24	-	-
2022	NYMEX Henry Hub	Two-way Collars	17,304,000	MMBtu	-	$2.70	$3.32
Q1-Q3 2023	NYMEX Henry Hub	Two-way Collars	6,999,000	MMBtu	-	$2.42	$2.94
		Total	32,312,000				
Natural Gas Basis (1)							
Q1-Q2 2022	NNG Ventura to NYMEX	Fixed Price Swaps	6,230,000	MMBtu	$0.51	-	-
Q1-Q2 2023	NNG Ventura to NYMEX	Fixed Price Swaps	4,740,000	MMBtu	$0.20	-	-
		Total	10,970,000				
NGL - Propane							
2022	Mont Belvieu	Fixed Price Swaps	19,110,000	Gallons	$1.08	-	-
2022	Conway	Fixed Price Swaps	19,110,000	Gallons	$1.17	-	-
		Total	38,220,000				

(1) The weighted average price associated with the natural gas basis swaps shown in the table above represents the average fixed differential to NYMEX as stated in the related contracts, which is compared to the Northern Natural Gas Ventura Index ("NNG Ventura") for each period. If NYMEX combined with the fixed differential as stated in each contract is higher than the NNG Ventura index price at any settlement date, the Company receives the difference. Conversely, if the NNG Ventura index price is higher than NYMEX combined with the fixed differential, the Company pays the difference.

Subsequent to December 31, 2021, the Company entered into additional crude oil, natural gas, natural gas basis and NGL swaps for 2022 and the first quarter of 2023. The table below details the Company's additional derivative contracts entered into through February 17, 2022.

					Weighted Average		
Settlement Period	**Index**	**Derivative Instrument**	**Total Volumes**	**Units**	**Swap Price**	**Floor**	**Ceiling**
Crude Oil							
2022	NYMEX WTI	Fixed Price Swaps	796,000	Bbl	$72.14	-	-
Q1 2023	NYMEX WTI	Fixed Price Swaps	810,000	Bbl	$75.14	-	-
		Total	1,606,000				
Natural Gas							
Q2-Q4 2022	NYMEX Henry Hub	Fixed Price Swaps	3,660,000	MMBtu	$4.03	-	-
Q1 2023	NYMEX Henry Hub	Fixed Price Swaps	1,800,000	MMBtu	$4.25	-	-
		Total	5,460,000				
Natural Gas Basis							
Q4 2022	NNG Ventura to NYMEX	Fixed Price Swaps	620,000	MMBtu	$1.17	-	-
Q1 2023	NNG Ventura to NYMEX	Fixed Price Swaps	1,180,000	MMBtu	$1.17	-	-
		Total	1,800,000				
NGL - Propane							
Q2 2022	Mont Belvieu	Fixed Price Swaps	1,911,000	Gallons	$1.03	-	-
2022	Conway	Fixed Price Swaps	39,606,000	Gallons	$1.04	-	-
		Total	41,517,000				

Effect of Chapter 11 Cases—The commencement of the Chapter 11 Cases constituted a termination event with respect to the Predecessor's then outstanding derivative instruments, which permitted the counterparties of such derivative instruments to terminate those derivatives. Such termination events were not stayed under the Bankruptcy Code. During April 2020, certain of the lenders under the Predecessor Credit Agreement elected to terminate their master ISDA agreements and outstanding derivatives with the Company

for aggregate settlement proceeds to the Company of $145 million. The proceeds from these terminations along with $13 million of March 2020 hedge settlement proceeds received in April 2020 were applied to the outstanding borrowings under the Predecessor Credit Agreement. An additional $23 million of settlement proceeds from terminated derivative positions were held in escrow until the completion of the Chapter 11 Cases. On the Emergence Date, these funds were released from restrictions and the proceeds were used to pay down a portion of the borrowings outstanding on the Predecessor Credit Agreement.

Derivative Instrument Reporting—All derivative instruments are recorded in the consolidated financial statements at fair value, other than derivative instruments that meet the "normal purchase normal sale" exclusion. Fair value gains and losses on the Company's derivative instruments are recognized immediately in earnings as derivatives (gain) loss, net in the consolidated statements of operations.

Offsetting of Derivative Assets and Liabilities. The Company nets its financial derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The following tables summarize the location and fair value amounts of all the Successor's derivative instruments in the consolidated balance sheets, as well as the gross recognized derivative assets, liabilities and amounts offset in the consolidated balance sheets (in thousands):

		December 31, 2021 (1)		
Not Designated as ASC 815 Hedges	**Balance Sheet Classification**	**Gross Recognized Assets/ Liabilities**	**Gross Amounts Offset**	**Net Recognized Fair Value Assets/ Liabilities**
Derivative Assets				
Commodity contracts - current	Prepaid expenses and other	$ 34,375	$ (31,002)	$ 3,373
Commodity contracts - non-current	Other long-term assets	13,674	(13,674)	-
Total derivative assets		$ 48,049	$ (44,676)	$ 3,373
Derivative Liabilities				
Commodity contracts - current	Derivative liabilities	$ 240,655	$ (31,002)	$ 209,653
Commodity contracts - non-current	Long-term derivative liabilities	60,394	(13,674)	46,720
Total derivative liabilities		$ 301,049	$ (44,676)	$ 256,373

		December 31, 2020 (1)		
Not Designated as ASC 815 Hedges	**Balance Sheet Classification**	**Gross Recognized Assets/ Liabilities**	**Gross Amounts Offset**	**Net Recognized Fair Value Assets/ Liabilities**
Derivative Assets				
Commodity contracts - current	Prepaid expenses and other	$ 14,287	$ (14,287)	$ -
Commodity contracts - non-current	Other long-term assets	19,991	(19,991)	-
Total derivative assets		$ 34,278	$ (34,278)	$ -
Derivative Liabilities				
Commodity contracts - current	Derivative liabilities	$ 63,772	$ (14,287)	$ 49,485
Commodity contracts - non-current	Long-term derivative liabilities	29,741	(19,991)	9,750
Total derivative liabilities		$ 93,513	$ (34,278)	$ 59,235

(1) All of the counterparties to the Company's financial derivative contracts subject to master netting arrangements are lenders under the Credit Agreement, which eliminates the need to post or receive collateral associated with its derivative positions other than that already provided under the Credit Agreement. Therefore, columns for cash collateral pledged or received have not been presented in these tables.

Contingent Features in Financial Derivative Instruments. None of the Company's derivative instruments contain credit-risk-related contingent features. Counterparties to the Company's financial derivative contracts are high credit-quality financial institutions that are lenders under the Credit Agreement. The Company uses Credit Agreement participants as hedge counterparties, since these institutions are secured equally with the holders of Whiting's credit facility, which eliminates the potential need to post additional collateral when Whiting is in a derivative liability position. As a result, the Company is not required to post letters of credit or corporate guarantees for its derivative counterparties in order to secure contract performance obligations.

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10. FAIR VALUE MEASUREMENTS

Cash, cash equivalents, restricted cash, accounts receivable and accounts payable are carried at cost, which approximates their fair value because of the short-term maturity of these instruments. The Credit Agreement has a recorded value that approximates its fair value since its variable interest rate is tied to current market rates and the applicable margins represent market rates.

The Company's derivative financial instruments are recorded at fair value and include a measure of the Company's own nonperformance risk or that of its counterparty, as appropriate. The following tables present information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2021 and 2020 (Successor), and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Level 1	Level 2	Level 3	Total Fair Value December 31, 2021
Financial Assets				
Commodity derivatives – current	$ -	$ 3,373	$ -	$ 3,373
Total financial assets	$ -	$ 3,373	$ -	$ 3,373
Financial Liabilities				
Commodity derivatives – current	$ -	$ 209,653	$ -	$ 209,653
Commodity derivatives – non-current	-	46,720	-	46,720
Total financial liabilities	$ -	$ 256,373	$ -	$ 256,373

	Level 1	Level 2	Level 3	Total Fair Value December 31, 2020
Financial Liabilities				
Commodity derivatives – current	$ -	$ 49,485	$ -	$ 49,485
Commodity derivatives – non-current	-	9,750	-	9,750
Total financial liabilities	$ -	$ 59,235	$ -	$ 59,235

The following methods and assumptions were used to estimate the fair values of the Company's financial assets and liabilities that are measured on a recurring basis:

Commodity Derivatives. Commodity derivative instruments consist mainly of swaps, collars, basis swaps and differential swaps for crude oil, natural gas and NGLs. The Company's swaps, collars and basis swaps are valued based on an income approach. Both the option and swap models consider various assumptions, such as quoted forward prices for commodities, time value and volatility factors. These assumptions are observable in the marketplace throughout the full term of the contract, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace and are therefore designated as Level 2 within the valuation hierarchy. The discount rates used in the fair values of these instruments include a measure of either the Company's or the counterparty's nonperformance risk, as appropriate. The Company utilizes its counterparties' valuations to assess the reasonableness of its own valuations.

Non-recurring Fair Value Measurements—Nonfinancial assets and liabilities, such as oil and natural gas properties and asset retirement obligations, are recognized at fair value on a nonrecurring basis. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances, such as the initial measurement or when an impairment occurs. The Company did not recognize any impairment write-downs with respect to its proved properties during 2021, the 2020 Successor Period or the year ended December 31, 2019 (Predecessor). The following tables present information about the Company's non-financial assets measured at fair value on a non-recurring basis during the 2020 Predecessor Period, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Predecessor				
	Net Carrying Value as of March 31, 2020	Fair Value Measurements Using			Loss (Before Tax) Three Months Ended March 31, 2020
		Level 1	Level 2	Level 3	
Proved property [(1)]	$ 816,234	$ -	$ -	$ 816,234	$ 3,732,096

(1) During the first quarter of 2020, certain proved oil and gas properties across the Company's Williston Basin resource play with a previous carrying amount of $4.5 billion were written down to their fair value as of March 31, 2020 of $816 million, resulting in a non-cash impairment charge of $3.7 billion, which was recorded within exploration and impairment expense. These impaired

properties were written down due to a reduction in anticipated future cash flows primarily driven by an expectation of sustained depressed oil prices and a resultant decline in future development plans for the properties assessed as of March 31, 2020.

	Predecessor				
	Net Carrying Value as of June 30, 2020	Fair Value Measurements Using			Loss (Before Tax) Six Months Ended June 30, 2020
		Level 1	Level 2	Level 3	
Proved property [(2)]	$ 85,418	$ -	$ -	$ 85,418	$ 409,079

(2) During the second quarter of 2020, other proved oil and gas properties in the Company's Williston Basin resource play with a previous carrying amount of $494 million were written down to their fair value as of June 30, 2020 of $85 million, resulting in a non-cash impairment charge of $409 million, which was recorded within exploration and impairment expense. These impaired properties were written down due to a reduction in anticipated future cash flows primarily driven by an expectation of sustained depressed oil prices and a resultant decline in future development plans for the properties assessed as of June 30, 2020.

Predecessor Proved Property Impairments. The Company tests proved property for impairment whenever events or changes in circumstances indicate that the fair value of these assets may be reduced below their carrying value. As a result of the significant decrease in the forward price curves for crude oil and natural gas during the first and second quarters of 2020, the associated decline in anticipated future cash flows and the resultant decline in future development plans for the properties, the Company performed proved property impairment tests as of March 31, 2020 and June 30, 2020. The fair value was ascribed using an income approach based on the net discounted future cash flows from the producing properties and related assets. The discounted cash flows were based on management's expectations for the future. Unobservable inputs included estimates of future oil and gas production from the Company's reserve reports, commodity prices based on forward strip price curves (adjusted for basis differentials) as of March 31, 2020 and June 30, 2020, operating and development costs, expected future development plans for the properties and a discount rate of 16% and 17% as of March 31, 2020 and June 30, 2020, respectively, based on a weighted-average cost of capital (all of which were designated as Level 3 inputs within the fair value hierarchy). The impairment tests indicated that proved property impairments had occurred, and the Company therefore recorded non-cash impairment charges to reduce the carrying value of the impaired properties to their fair value at March 31, 2020 and June 30, 2020.

Chapter 11 Emergence and Fresh Start Accounting. On the Emergence Date, the Company emerged from the Chapter 11 Cases and adopted fresh start accounting, which resulted in the Company becoming a new entity for financial reporting purposes. Upon the adoption of fresh start accounting, the Company's assets and liabilities were recorded at their fair values as of September 1, 2020. The inputs utilized in the valuation of the Company's most significant asset, its oil and gas properties and related assets, included mostly unobservable inputs which fall within Level 3 of the fair value hierarchy. Such inputs included estimates of future oil and gas production from the Company's reserve reports, commodity prices based on forward strip price curves (adjusted for basis differentials) as of September 1, 2020, operating and development costs, expected future development plans for the properties and a discount rate of 14% based on a weighted-average cost of capital. The Company also recorded its asset retirement obligations at fair value as a result of fresh start accounting. The inputs utilized in valuing the asset retirement obligations were mostly Level 3 unobservable inputs, including estimated economic lives of oil and natural gas wells as of the Emergence Date, anticipated future plugging and abandonment costs and an appropriate credit-adjusted risk free rate to discount such costs. Refer to the "Fresh Start Accounting" footnote for a detailed discussion of the fair value approaches used by the Company.

Williston Basin Acquisition. On September 14, 2021, the Company acquired interests in producing assets and undeveloped acreage in the Williston Basin, as further described in the "Acquisitions and Divestitures" footnote above. The assets acquired and liabilities assumed were recorded at their fair values as of September 14, 2021. The inputs utilized in the valuation of the oil and gas properties and related assets acquired included mostly unobservable inputs which fall within Level 3 of the fair value hierarchy. Such inputs included estimates of future oil and gas production from the properties' reserve reports, commodity prices based on forward strip price curves (adjusted for basis differentials) as of September 14, 2021, operating and development costs, expected future development plans for the properties and a discount rate of 11% based on a weighted-average cost of capital. The Company also recorded the asset retirement obligations assumed at fair value. The inputs utilized in valuing the asset retirement obligations were mostly Level 3 unobservable inputs, including estimated economic lives of oil and natural gas wells as of September 14, 2021, anticipated future plugging and abandonment costs and an appropriate credit-adjusted risk-free rate to discount such costs.

11. REVENUE RECOGNITION

The tables below present the disaggregation of revenue by product and transaction type for the periods presented (in thousands):

	Successor		Predecessor	
OPERATING REVENUES	**Year Ended December 31, 2021**	**Four Months Ended December 31, 2020**	**Eight Months Ended August 31, 2020**	**Year Ended December 31, 2019**
Oil sales	$ 1,251,015	$ 254,024	$ 440,820	$ 1,492,218
NGL and natural gas sales	260,822	19,334	18,184	80,027
Oil, NGL and natural gas sales	1,511,837	273,358	459,004	1,572,245
Purchased gas sales	21,644	-	-	-
Total operating revenues	$ 1,533,481	$ 273,358	$ 459,004	1,572,245

Whiting receives payment for product sales from one to three months after delivery. At the end of each month when the performance obligation is satisfied, the variable consideration can be reasonably estimated and amounts due from customers are accrued in accounts receivable trade, net in the consolidated balance sheets. As of December 31, 2021 and 2020 (Successor), such receivable balances were $178 million and $88 million, respectively. Variances between the Company's estimated revenue and actual payments are recorded in the month the payment is received, however, differences have been and are insignificant. Accordingly, the variable consideration is not constrained.

12. SHAREHOLDERS' EQUITY

Common Stock—On the Emergence Date, the Successor filed an amended and restated certificate of incorporation with the Delaware Secretary of State to provide for, among other things, the authority to issue a total of 550,000,000 shares of all classes of capital stock, of which 500,000,000 shares are common stock, par value $0.001 per share (the "New Common Stock") and 50,000,000 shares are preferred stock, par value $0.001 per share.

Upon emergence from the Chapter 11 Cases on the Emergence Date all existing shares of the Predecessor's common stock were cancelled and the Successor issued 38,051,125 shares of New Common Stock. Refer to the "Chapter 11 Emergence" and "Fresh Start Accounting" footnotes for more information.

Warrants—On the Emergence Date and pursuant to the Plan, the Successor entered into warrant agreements with Computershare Inc. and Computershare Trust Company, N.A., as warrant agent, which provide for (i) the Successor's issuance of up to an aggregate of 4,837,821 Series A warrants to acquire the New Common Stock (the "Series A Warrants") to certain former holders of the Predecessor's common stock and (ii) the Successor's issuance of up to an aggregate of 2,418,910 Series B warrants to acquire New Common Stock (the "Series B Warrants" and together with the Series A Warrants, the "Warrants") to certain former holders of the Predecessor's common stock. The Warrants were recorded at fair value in additional paid-in capital upon issuance on the Emergence Date, as further detailed in the "Fresh Start Accounting" footnote.

The Series A Warrants are exercisable from the date of issuance until the fourth anniversary of the Emergence Date, at which time all unexercised Series A Warrants will expire and the rights of the holders of such warrants to acquire New Common Stock will terminate. The Series A Warrants are initially exercisable for one share of New Common Stock per Series A Warrant at an initial exercise price of $73.44 per Series A Warrant (the "Series A Exercise Price").

The Series B Warrants are exercisable from the date of issuance until the fifth anniversary of the Emergence Date, at which time all unexercised Series B Warrants will expire and the rights of the holders of such warrants to acquire New Common Stock will terminate. The Series B Warrants are initially exercisable for one share of New Common Stock per Series B Warrant at an initial exercise price of $83.45 per Series B Warrant (the "Series B Exercise Price" and together with the Series A Exercise Price, the "Exercise Prices").

In the event that a holder of Warrants elects to exercise their option to acquire shares of New Common Stock, the Company shall issue a net number of exercised shares of New Common Stock. The net number of exercised shares is calculated as (i) the number of Warrants exercised multiplied by (ii) the difference between the 30-day daily volume weighted average price ("VWAP") of the New Common Stock leading up to the exercise date (the "Current Market Price") and the relevant exercise price, calculated as a percentage of the Current Market Price on the exercise date.

Pursuant to the warrant agreements, no holder of a Warrant, by virtue of holding or having a beneficial interest in a Warrant, will have the right to vote, receive dividends, receive notice as stockholders with respect to any meeting of stockholders for the election of Whiting's directors or any other matter, or exercise any rights whatsoever as a stockholder of Whiting unless, until and only to the extent such holders become holders of record of shares of New Common Stock issued upon settlement of the Warrants.

The number of shares of New Common Stock for which a Warrant is exercisable and the Exercise Prices are subject to adjustment from time to time upon the occurrence of certain events, including stock splits, reverse stock splits or stock dividends to holders of New Common Stock or a reclassification in respect of New Common Stock.

Settlement of Bankruptcy Claims—Prior to the Chapter 11 Cases, WOG was party to various executory contracts with BNN Western, LLC, subsequently renamed Tallgrass Water Western, LLC ("Tallgrass"), including a Produced Water Gathering and Disposal Agreement (the "PWA"). In January 2021, WOG and Tallgrass entered into a settlement agreement to resolve all of the related claims before the Bankruptcy Court relating to such executory contracts, terminated the PWA and entered into a new Water Transport, Gathering and Disposal Agreement. In accordance with the settlement agreement, Whiting made a $2 million cash payment and issued 948,897 shares of New Common Stock pursuant to the confirmed Plan to a Tallgrass entity in February 2021.

As discussed in the "Chapter 11 Emergence" footnote, an additional 2,121,304 shares of New Common Stock remain reserved as of December 31, 2021 for potential future distribution to certain general unsecured claimants whose claim values are pending resolution in the Bankruptcy Court.

13. STOCK-BASED COMPENSATION

Equity Incentive Plan—As discussed in the "Chapter 11 Emergence" and "Fresh Start Accounting" footnotes, on the Emergence Date and pursuant to the terms of the Plan, all of the Predecessor's common stock and any unvested awards based on such common stock were cancelled and holders were issued an aggregate of 1,233,495 shares of Successor common stock on a pro rata basis. On September 1, 2020, the Successor's Board adopted the Whiting Petroleum Corporation 2020 Equity Incentive Plan (the "2020 Equity Plan"), which replaced the Predecessor's equity plan (the "Predecessor Equity Plan"). The 2020 Equity Plan provides the authority to issue 4,035,885 shares of the Successor's common stock. Any shares forfeited under the 2020 Equity Plan will be available for future issuance under the 2020 Equity Plan. However, shares netted for tax withholding under the 2020 Equity Plan will be cancelled and will not be available for future issuance. Under the 2020 Equity Plan, during any calendar year no non-employee director participant may be granted awards having a grant date fair value in excess of $500,000. As of December 31, 2021, 3,034,539 shares of common stock remained available for grant under the 2020 Equity Plan.

Historically, the Company has granted service-based restricted stock awards ("RSAs") and restricted stock units ("RSUs") to executive officers and employees, which generally vest ratably over a two, three or five-year service period. The Company has granted service-based RSAs and RSUs to directors, which generally vest over a one-year service period. In addition, the Company has granted performance share awards ("PSAs") and performance share units ("PSUs") to executive officers that are subject to market-based vesting criteria, which generally vest over a three-year service period. Additionally, certain of the Company's executive officers can receive shares for any short-term bonus awarded in excess of the targets set by the Board at the beginning of each year. The Company accounts for forfeitures of awards granted under these plans as they occur in determining compensation expense. The Company recognizes compensation expense for all awards subject to market-based vesting conditions regardless of whether it becomes probable that these conditions will be achieved or not, and compensation expense for share-settled awards is not reversed if vesting does not actually occur.

Successor Awards under 2020 Equity Plan

During September and October 2020, 89,021 shares of service-based RSUs were granted to executive officers and directors. The Company determines compensation expense for these share-settled awards using their fair value at the grant date based on the closing bid price of the Company's common stock on such date. The weighted average grant date fair value of these RSUs was $17.47 per share.

In September 2020, 189,900 shares of market-based RSUs were granted to executive officers. The awards vest upon the Successor's common stock trading for 20 consecutive trading days above a certain daily VWAP as follows: 50% vested when the VWAP exceeded $32.57 per share, an additional 25% vested when the daily VWAP exceeded $48.86 per share and the final 25% vested when the daily VWAP exceeded $65.14 per share. The Company recognizes compensation expense based on the fair value as determined by a Monte Carlo valuation model (the "Monte Carlo Model") over the expected vesting period, which was estimated to be between 1.8 and 3.8 years at the grant date. Upon vesting, any unrecognized compensation expense related to the shares is accelerated and recognized. The weighted average grant date fair value of these RSUs was $6.54 per share. More information on the inputs to the Monte Carlo Model are explained below. During the year ended December 31, 2021, the first 75% of these awards vested as the Company's VWAP exceeded both $32.57 and $48.86 per share for 20 consecutive trading days during the period. On January 31, 2022, the remaining 25% of these awards vested as the Company's VWAP exceeded $65.14 per share for 20 consecutive days as of that date.

During the year ended December 31, 2021, (i) 362,056 shares of service-based RSUs were granted to executive officers and employees, which vest ratably over either a two or three-year service period, (ii) 117,607 shares of service-based RSUs were granted to executive officers, which cliff vest on the fifth anniversary of the grant date and (iii) 23,730 shares of service-based RSUs were granted to the Board, which vest over a one-year period. The Company determines compensation expense for these share-settled awards using their fair value at the grant date, which is based on the closing bid price of the Company's common stock on such date. The weighted average grant date fair value of serviced-based RSUs was $24.00 per share for the year ended December 31, 2021.

During the year ended December 31, 2021, 232,150 shares of PSUs subject to certain market-based vesting criteria were granted to executive officers. These market-based awards vest at the end of the performance period, which is December 31, 2023, and the number of shares that vest at the end of the performance period is determined based on two performance goals: (i) 116,075 shares vest based on the Company's annualized absolute total stockholder return ("ATSR") over the performance period as compared to certain preestablished target returns and (ii) 116,075 shares vest based on the Company's relative total stockholder return ("RTSR") compared to the stockholder returns of a preestablished peer group of companies over the performance period. The number of awards earned could range from zero up to two times the number of shares initially granted, all of which will be settled in shares. The weighted average grant date fair value of the market-based awards was $29.32 per share and $32.33 per share for the ATSR and RTSR awards, respectively, as determined by the Monte Carlo Model, which is described further below.

For awards subject to market conditions, the grant date fair value is estimated using the Monte Carlo Model, which is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility for the market-based RSUs was calculated based on the observed volatility of peer public companies. Expected volatility for the market-based PSUs was calculated based on the historical and implied volatility of Whiting's common shares (adjusted for the impacts of the Chapter 11 Cases). The risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the vesting period for the relevant award.

The key assumptions used in valuing these market-based awards were as follows:

	2021 PSUs	2020 RSUs
Number of simulations	500,000	100,000
Expected volatility	81%	40%
Risk-free interest rate	0.17%	0.66%
Dividend yield	—	—

The following table shows a summary of the Company's service-based and market-based awards activity for the year ended December 31, 2021:

	Number of Awards			Weighted Average
	Service-Based RSUs	Market-Based RSUs	Market-Based PSUs	Grant Date Fair Value
Nonvested awards, December 31, 2020	89,021	189,900	-	$ 10.03
Granted	503,393	-	232,150	26.15
Vested	(63,040)	(142,425)	-	10.11
Forfeited	(13,118)	-	-	24.39
Nonvested awards, December 31, 2021	516,256	47,475	232,150	$ 24.67

During January 2022, certain executives received shares of common stock as part of their incentive compensation package which represented the portion of their 2021 short-term bonus that was in excess of their target bonus established by the Board at the beginning of the year, in accordance with their employment agreements. As the bonus amount was determined prior to December 31, 2021, the Company recorded approximately $1 million in stock compensation expense related to these awards during the year ended December 31, 2021, which was recorded to accrued liabilities and other in the Company's consolidated balance sheets as of December 31, 2021.

The Company recognized $11 million and $1 million in stock-based compensation expense during the year ended December 31, 2021 and the 2020 Successor Period, respectively. As of December 31, 2021, there was $11 million of unrecognized compensation cost related to unvested awards granted under the 2020 Equity Plan. That cost is expected to be recognized over a weighted average period of 2.3 years.

For the year ended December 31, 2021, the total fair value of the Company's service-based and market-based awards vested was $9 million.

Predecessor Awards under Predecessor Equity Plan

During the eight months ended August 31, 2020 and the year ended December 31, 2019, 53,198 and 467,055 shares, respectively, of share-settled service-based RSAs and RSUs were granted to executive officers and directors. The Company determined compensation expense for these awards using their fair value at the grant date, which was based on the closing bid price of the Company's common stock on such date. The weighted average grant date fair value of these service-based RSAs and RSUs was $4.94 per share and $24.65 per share for the eight months ended August 31, 2020 and the year ended December 31, 2019, respectively. On March 31, 2020, all of the RSAs issued to executive officers in 2020 were forfeited and concurrently replaced with cash incentives. Refer to "2020 Compensation Adjustments" below for more information.

During the eight months ended August 31, 2020 and the year ended December 31, 2019, 1,616,504 and 774,665 shares, respectively, of cash-settled, service-based RSUs were granted to executive officers and employees. The Company determined compensation expense for these awards using the fair value at the end of each reporting period, which was based on the closing bid price of the Company's common stock on such date. On March 31, 2020, all of the RSUs issued to executive officers in 2020 were forfeited and concurrently replaced with cash incentives. Refer to "2020 Compensation Adjustments" below for more information.

During the eight months ended August 31, 2020 and the year ended December 31, 2019, 1,665,153 and 347,493 shares, respectively, of PSAs and PSUs subject to certain market-based vesting criteria were granted to executive officers. These market-based awards were to cliff vest on the third anniversary of the grant date, however, on March 31, 2020, all of the PSAs and PSUs issued to executive officers in 2020 were forfeited and concurrently replaced with cash incentives. Refer to "2020 Compensation Adjustments" below for more information.

The grant date fair value of these PSAs and PSUs was estimated using the Monte Carlo Model. Expected volatility was calculated based on the historical volatility and implied volatility of Whiting's common stock, and the risk-free interest rate was based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period. The key assumptions used in valuing these market-based awards were as follows:

	2020	2019
Number of simulations	2,500,000	2,500,000
Expected volatility	76.52%	72.95%
Risk-free interest rate	1.51%	2.60%
Dividend yield	—	—

The weighted average grant date fair value of the market-based awards that were to be settled in shares as determined by the Monte Carlo valuation model was $4.31 per share and $25.97 per share in the 2020 Predecessor Period and 2019, respectively.

For the eight months ended August 31, 2020 and the year ended December 31, 2019, the total fair value of the Company's service-based and market-based awards vested was $1 million and $12 million, respectively.

Total stock-based compensation expense for Predecessor restricted stock awards for the eight months ended August 31, 2020 and the year ended December 31, 2019 was $3 million and $8 million, respectively. As a result of the implementation of the Plan, the Company accelerated $4 million of expense related to unvested awards, which was recorded to reorganization items, net in the consolidated statements of operations during the 2020 Predecessor Period. Refer to the "Fresh Start Accounting" footnote for more information.

2020 Compensation Adjustments. All of the RSAs, RSUs, PSAs and PSUs granted to executive officers in 2020 under the Predecessor Equity Plan were forfeited on March 31, 2020 and were replaced with cash retention incentives. The cash retention incentives were subject to a service period and were subject to claw back provisions if an executive officer terminated employment for any reason other than a qualifying termination prior to the earlier of (i) the effective date of a plan of reorganization approved under chapter 11 of the Bankruptcy Code or (ii) March 30, 2021. The transactions were considered concurrent replacements of the stock compensation awards previously issued. As such, the $12 million fair value of the awards, consisting of the after-tax value of the cash incentives, was capitalized and amortized over the period from the Petition Date to the Emergence Date, which amortization is included in general and administrative expenses in the consolidated statements of operations for the 2020 Predecessor Period. The difference between the cash and after-tax value of the cash retention incentives of approximately $9 million, which was not subject to the claw back provisions contained within the agreements, was expensed to general and administrative expenses in the 2020 Predecessor Period.

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14. INCOME TAXES

Income tax expense (benefit) consists of the following (in thousands):

	Successor		Predecessor	
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Year Ended December 31, 2019
Current Income Tax Expense (Benefit)				
Federal	$ 878	$ -	$ (1,028)	$ -
State	32	-	-	-
Foreign	-	2,463	3,746	-
Total current income tax expense	910	2,463	2,718	-
Deferred Income Tax Expense (Benefit)				
Federal	-	-	-	2,140
State	-	-	-	(3,513)
Foreign	-	(14,501)	(59,092)	73,593
Total deferred income tax expense (benefit)	-	(14,501)	(59,092)	72,220
Total	$ 910	$ (12,038)	$ (56,374)	$ 72,220

Income tax expense (benefit) differed from amounts that would result from applying the U.S. statutory income tax rate of 21% to income before income taxes as follows (in thousands):

	Successor		Predecessor	
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Year Ended December 31, 2019
Federal and State Tax Expense (Benefit)				
U.S. statutory income tax expense (benefit)	$ 90,051	$ 5,676	$ (844,471)	$ (35,479)
State income taxes, net of federal benefit	13,883	724	(148,305)	(8,288)
Executive compensation	1,757	(765)	2,182	-
Reorganization costs	-	-	10,584	-
IRC Section 382 and other restructuring adjustments	(4,824)	549,323	5,433	-
State net operating loss adjustments due to subsidiary restructuring	-	25,864	-	-
Market-based equity awards	(1,442)	415	441	910
Other	(3,032)	(1,105)	(4,040)	1,812
Valuation allowance	(95,483)	(580,132)	977,148	39,672
Total federal and state tax expense (benefit)	910	-	(1,028)	(1,373)
Foreign Tax Expense (Benefit)				
Foreign tax expense (benefit)	-	2,463	3,746	(147)
ASC 740-30-25-19 outside basis difference recognition	-	(14,501)	(59,092)	73,740
Total foreign tax expense (benefit)	-	(12,038)	(55,346)	73,593
Total	$ 910	$ (12,038)	$ (56,374)	$ 72,220

The principal components of the Company's deferred income tax assets and liabilities at December 31, 2021 and 2020 were as follows (in thousands):

	Successor	
	December 31, 2021	December 31, 2020
Deferred Income Tax Assets		
Net operating loss carryforward	$ 301,532	$ 248,835
Derivative instruments	59,678	14,119
Asset retirement obligations	24,548	23,390
Restricted stock compensation	1,988	123
EOR credit carryforwards	7,946	7,946
Lease obligations	4,681	9,409
Oil and gas properties	93,896	291,698
Other	1,459	5,011
Total deferred income tax assets	495,728	600,531
Less valuation allowance	(489,812)	(585,296)
Net deferred income tax assets	5,916	15,235
Deferred Income Tax Liabilities		
Trust distributions	1,439	6,061
Lease assets	4,477	9,174
Total deferred income tax liabilities	5,916	15,235
Total net deferred income tax liabilities	$ -	$ -

Internal Revenue Code ("IRC") Section 382 addresses company ownership changes and specifically limits the utilization of certain deductions and other tax attributes on an annual basis following an ownership change. As a result of the chapter 11 reorganization and related transactions, the Successor experienced an ownership change within the meaning of IRC Section 382 on the Emergence Date. This ownership change subjected certain of the Company's tax attributes to an IRC Section 382 limitation. The ownership changes and resulting annual limitation will result in the expiration of net operating loss carryforwards ("NOLs") or other tax attributes otherwise available, with a corresponding decrease in the Company's valuation allowance.

As of December 31, 2021, the Company had federal NOL carryforwards of $3.3 billion, which are subject to IRC Section 382 limitations due to the Company incurring a Section 382 ownership event at the time of emergence from the Chapter 11 Cases. The Company currently estimates that approximately $2.2 billion of these federal NOLs will expire before they are able to be used. The determination of the state NOL carryforwards is dependent upon apportionment percentages and state laws that can change from year to year and that can thereby impact the amount of such carryforwards. If unutilized, the majority of the federal and state NOLs will expire between 2022 and 2037. Any federal NOLs generated in 2018 or subsequent do not expire.

EOR credits are a credit against federal income taxes for certain costs related to extracting high-cost oil, utilizing certain prescribed enhanced tertiary recovery methods. As of December 31, 2021, the Company had recognized aggregate EOR credits of $8 million. As a result of a IRC Section 382 limitation in July 2016, the Company recorded a full valuation allowance on these credits.

In assessing the realizability of deferred tax assets ("DTAs"), management considers whether it is more likely than not that some portion, or all, of the Company's DTAs will not be realized. In making such determination, the Company considers all available positive and negative evidence, including future reversals of temporary differences, tax-planning strategies and projected future taxable income and results of operations. If the Company concludes that it is more likely than not that some portion, or all, of its DTAs will not be realized, the tax asset is reduced by a valuation allowance. At December 31, 2021, the Company had a valuation allowance totaling $490 million.

During the fourth quarter of 2019, the Company determined it no longer had the ability to indefinitely prevent the reversal of the outside basis difference related to Whiting Canadian Holding Company ULC, Whiting's wholly owned subsidiary, which at that time owned a portion of Whiting's U.S. assets obtained through the acquisition of Kodiak Oil and Gas Corporation during 2014. Accordingly, the Company revised its assessment related to noncurrent Canadian deferred taxes pursuant to ASC 740-30-25-17 and recognized a $74 million deferred tax liability as well as the same amount of deferred income tax expense as of and for the year ended December 31, 2019 (Predecessor) associated with the outside basis difference related to Whiting Canadian Holding Company ULC. During the third quarter of 2020, the Company partially executed a legal entity restructuring plan to reduce administrative expenses and burden with a simplified corporate structure. The final steps of the legal entity restructuring were completed during the fourth quarter of 2020, ultimately resulting with Whiting Oil & Gas, under its parent Whiting Petroleum Corporation, holding all of the Company's oil and gas operations. As a result of impacts from fresh start accounting, the Company reduced its deferred tax liability for its outside basis difference related to Whiting Canadian Holding Company ULC and recorded a tax benefit of $55 million during the 2020 Predecessor Period. As a result

of the restructuring, the Company reduced its deferred tax liability and recorded a tax benefit of $12 million during the 2020 Successor Period. The Company paid Canadian cash taxes of $6 million during the fourth quarter of 2020.

As of December 31, 2021 and 2020, the Company did not have any uncertain tax positions. For the periods presented, the Company did not recognize any interest or penalties with respect to unrecognized tax benefits, nor did the Company have any such interest or penalties previously accrued.

The Company files income tax returns in the U.S. federal jurisdiction and in various states, each with varying statutes of limitations. The 2018 through 2020 tax years generally remain subject to examination by federal and state tax authorities. Additionally, the Company has Canadian income tax filings which remain subject to examination by the related tax authorities for the 2017 through 2020 tax years.

15. EARNINGS PER SHARE

The reconciliations between basic and diluted earnings (loss) per share are as follows (in thousands, except per share data):

	Successor		Predecessor	
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Year Ended December 31, 2019
Basic Earnings (Loss) Per Share				
Net income (loss)	$ 427,906	$ 39,073	$ (3,965,461)	$ (241,166)
Weighted average shares outstanding, basic	39,006	38,080	91,423	91,285
Earnings (loss) per common share, basic	$ 10.97	$ 1.03	$ (43.37)	$ (2.64)
Diluted Earnings (Loss) Per Share				
Net income (loss)	$ 427,906	$ 39,073	$ (3,965,461)	$ (241,166)
Weighted average shares outstanding, basic	39,006	38,080	91,423	91,285
Service-based awards and market-based awards	686	39	-	-
Weighted average shares outstanding, diluted	39,692	38,119	91,423	91,285
Earnings (loss) per common share, diluted	$ 10.78	$ 1.03	$ (43.37)	$ (2.64)

Successor

During 2021 and the 2020 Successor Period, the diluted earnings per share calculations exclude the effect of common shares that may be issued pursuant to the Series A Warrants and Series B Warrants, as such Warrants were out-of-the-money as of December 31, 2021 and 2020. During 2021, the diluted earnings per share calculation also excludes the effect of 47,475 shares of market-based awards that did not meet the market-based vesting criteria as of December 31, 2021 and 2,121,304 contingently issuable shares related to the settlement of general unsecured claims associated with the Chapter 11 Cases, as all necessary conditions had not been met to be considered dilutive shares as of December 31, 2021. During the 2020 Successor Period, the diluted earnings per share calculation also excludes the effect of 189,900 shares of market-based awards that did not meet the market-based vesting criteria as of December 31, 2020 and 3,021,304 contingently issuable shares related to the settlement of general unsecured claims associated with the Chapter 11 Cases, as all necessary conditions had not been met to be considered dilutive shares as of December 31, 2020. However, subsequent to December 31, 2020 the Company issued 948,897 of such contingently issuable shares. The basic weighted average shares outstanding calculation for the 2020 Successor Period includes 48,897 of these shares as all necessary conditions to be included in the calculation had been satisfied during the period. Refer to the “Shareholders’ Equity” footnote for more information on this share issuance.

Predecessor

For the eight months ended August 31, 2020, the Company had a net loss and therefore the diluted earnings per share calculation excludes the antidilutive effect of 314,896 shares of service-based awards. In addition, the diluted earnings per share calculation for the eight months ended August 31, 2020 excludes the effect of 29,465 common shares for stock options that were out of the money as of August 31, 2020. All outstanding stock options were canceled upon emergence from bankruptcy on the Emergence Date.

For the year ended December 31, 2019 the Company had a net loss and therefore the diluted earnings per share calculation for that period excludes the anti-dilutive effect of 344,671 shares of service-based awards and 3,511 shares of market-based awards. In addition, the diluted earnings per share calculation for the year ended December 31, 2019 excludes the effect of 45,588 common shares for stock options that were out of the money as of December 31, 2019. All outstanding stock options were canceled upon emergence from bankruptcy on the Emergence Date.

Refer to the "Stock-Based Compensation" footnote for further information on the Company's service-based awards and market-based awards.

The Company had the option to settle conversions of the Convertible Senior Notes with cash, shares of common stock or any combination thereof. As the conversion value of the Convertible Senior Notes did not exceed the principal amount of the notes for any time during the conversion period ending April 1, 2020, there was no impact to diluted earnings per share or the related disclosures for any of the periods presented.

16. COMMITMENTS AND CONTINGENCIES

Pipeline Transportation Agreements—The Company has an agreement through January 2022 with a third-party to facilitate the delivery of its produced oil, gas and NGLs to market. As of December 31, 2021, the Company estimated the minimum future commitments under this transportation agreement to be approximately $0.4 million through January 2022.

Previously, the Company had an agreement with a third-party to facilitate the delivery of its produced oil, gas and NGLs to market for production related to its Redtail field. Under this contract, the Company had committed to pay fixed monthly reservation fees on dedicated pipelines for natural gas and NGL transportation capacity, plus additional variable charges based on actual transportation volumes. As a result of the divestiture of all the Company's interests in its Redtail field in September 2021, this contract was transferred to the buyer. Refer to the "Acquisitions and Divestitures" footnote for more information.

During 2021, the 2020 Successor Period, the 2020 Predecessor Period and the year ended December 31, 2019, the cost of transportation of crude oil, natural gas and NGLs under these contracts amounted to $4 million, $1 million, $1 million and $2 million, respectively.

Delivery Commitments—The Company has one physical delivery contract which requires the Company to deliver fixed volumes of crude oil. This delivery commitment became effective in April 2020 and is tied to crude oil production from Whiting's Sanish field in Mountrail County, North Dakota. Under the terms of the agreement, Whiting has committed to deliver 15 MBbl/d for a term of 4.1 years. The Company believes its production and reserves at the Sanish field are sufficient to fulfill this delivery commitment, and therefore expects to avoid any payments for deficiencies under this contract.

The Company has another physical delivery contract effective through June 30, 2024 which is tied to oil production in North Dakota and Montana. Under the terms of the contract, the Company is required to deliver 5 MBbl/d during the delivery term. If the Company fails to deliver any of the committed volumes during the term of the contract, the Company will be in immediate default under the contract and will be required to pay liquidated damages for the remaining term of the contract. The Company believes its production and reserves are sufficient to fulfill this delivery commitment, and therefore expects to avoid any payments for deficiencies under this contract.

Chapter 11 Cases—On April 1, 2020, the Debtors filed the Chapter 11 Cases seeking relief under the Bankruptcy Code. The filing of the Chapter 11 Cases allowed the Company to, upon approval of the Bankruptcy Court, assume, assign or reject certain contractual commitments, including certain executory contracts. Refer to the "Chapter 11 Emergence" footnote for more information. Generally, the rejection of an executory contract or unexpired lease is treated as a pre-petition breach of such contract and, subject to certain exceptions, relieves the Company from performing future obligations under such contract but entitles the counterparty or lessor to a pre-petition general unsecured claim for damages caused by such deemed breach. The claims resolution process is ongoing and certain of these claims remain subject to the jurisdiction of the Bankruptcy Court. To the extent that these Bankruptcy Court proceedings result in unsecured claims being allowed against the Company, such claims may be satisfied through the issuance of shares of the Successor's common stock or other remedy or agreement under and pursuant to the Plan.

Arguello Inc. and Freeport-McMoRan Oil & Gas LLC. WOG had interests in federal oil and gas leases in the Point Arguello Unit located offshore in California. While those interests have expired, pursuant to certain related agreements (the "Point Arguello Agreements"), WOG may be subject to abandonment and decommissioning obligations. WOG and Whiting Petroleum Corporation rejected the related contracts pursuant to the Plan. On October 1, 2020, Arguello Inc. and Freeport-McMoRan Oil & Gas LLC, individually and in its capacity as the designated Point Arguello Unit operator (collectively, the "FMOG Entities") filed with the Bankruptcy Court an application for allowance of certain administrative claims arguing the FMOG Entities were entitled to recover Whiting's proportionate share of decommissioning obligations owed to the U.S. government through subrogation to the U.S. government's economic rights. The FMOG Entities' application alleged administrative claims of approximately $25 million for estimated decommissioning costs owed to the U.S. government, at least $60 million of estimated decommissioning costs owed to the FMOG Entities and other insignificant amounts. On September 14, 2020, the FMOG Entities also filed with the Bankruptcy Court proofs of claim for rejection damages to serve as an alternative course of action in the event that a court should determine that the FMOG Entities do not hold any applicable administrative claims. The U.S. government may also be able to bring claims against WOG directly for decommissioning costs. On February 18, 2021, WOG entered into a stipulation and agreed order with the United States Department of the Interior, Bureau of Safety & Environmental Enforcement (the "BSEE") pursuant to which the BSEE withdrew its proofs of claims against Whiting Petroleum Corporation and WOG and acknowledged their respective rights and obligations pursuant to the Plan. On March 26, 2021, the FMOG Entities withdrew their administrative claim for the recovery of Whiting's proportionate share of costs incurred after August 31, 2020 to fulfill obligations owed to the U.S. Government on the basis of subrogation to the Government's economic rights. The FMOG Entities continue to assert certain other administrative claims and have reserved the right to assert claims for the recovery of Whiting's share of the decommissioning costs incurred after August 31, 2020 based on the theory of equitable subrogation. On September 14, 2021, Whiting Petroleum Corporation and WOG filed an objection in the Bankruptcy Court, seeking an order partially disallowing the FMOG Entities' claims. The Bankruptcy Court has not issued a ruling on the damages for rejection of the Point Arguello Agreements and it is possible that a settlement with the FMOG Entities could be reached. Although WOG intends to vigorously pursue its objection in this legal proceeding, if the FMOG Entities were to prevail on certain of their respective claims (including the reserved claims) on the merits, the Company enters into a settlement agreement or the U.S. government were to bring claims against WOG, Whiting could be liable for claims that must be paid or otherwise satisfied under and pursuant to the Plan including through an equity issuance, cash payment or otherwise.

It is possible that as a result of the legal proceedings associated with the bankruptcy claims administration process or the matter detailed above, the Bankruptcy Court may rule that the claim should be afforded some treatment other than as a general unsecured claim. This outcome could require the Company to make cash payments to settle those claims instead of or in addition to issuing shares of the Successor's common stock, and such cash payments would result in losses in future periods. In addition, it is also reasonably possible that a settlement with respect to such legal proceedings could be reached, in which case the settlement consideration would be paid or otherwise satisfied under and pursuant to the Plan, including through an equity issuance, cash payment or otherwise. As of December 31, 2021, the Company had $55 million of outstanding offers to settle claims from the Chapter 11 Cases in cash, rather than through the issuance of shares of Successor common stock reserved under the Plan for potential distribution to general unsecured claimants. If accepted, these settlements would be paid with cash on hand or borrowings under the Credit Agreement and would not result in the Company issuing shares of the Successor's common stock to resolve the claims. However, such claims remain subject to the jurisdiction of the Bankruptcy Court and it is reasonably possible that these claims could be resolved by the issuance of shares of the Successor's common stock. The ultimate amount of either a cash payment or number of shares of Successor common stock that may be issued to settle such claims is uncertain and cannot currently be reasonably estimated.

Litigation—The Company is subject to litigation, claims and governmental and regulatory proceedings arising in the ordinary course of business. The Company accrues a loss contingency for these lawsuits and claims when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. While the outcome of these lawsuits and claims cannot be predicted with certainty, it is the opinion of the Company's management that the loss for any litigation matters and claims that are reasonably possible to occur will not have a material adverse effect, individually or in the aggregate, on its consolidated financial position, cash flows or results of operations unless separately disclosed.

During 2020, the Company was involved in litigation related to a payment arrangement with a third party. In June 2020, the Company and the third party reached a settlement agreement resulting in the Company paying the third party a settlement amount of $14 million. The Company recognized $11 million in general and administrative expenses in the consolidated statements of operations for the year ended December 31, 2019 (Predecessor). The Company recorded $3 million of additional general and administrative expense in the consolidated statements of operations during the 2020 Predecessor Period upon settling this litigation. Upon settlement, the Company agreed to indemnify a party involved in the litigation for any further claims resulting from these matters up to $25 million. This indemnity will terminate on the date on which the statute of limitations for the relevant claims expires. The Company does not expect to pay additional amounts to this party as a result of this indemnity and thus has not recorded any liability related to the indemnity as of December 31, 2021 (Successor).

17. COMPANY RESTRUCTURINGS

During September 2020 and August 2019, the Company executed workforce reductions as part of an organizational redesign and cost reduction strategy to better align its business with the current operating environment and drive long-term value. For each of these workforce reductions, the Company incurred $8 million in net restructuring costs associated with one-time employee termination benefits. These charges were recorded to general and administrative expenses during the relevant periods in the consolidated statements of operations.

18. SUBSEQUENT EVENTS

Williston Basin Acquisition**—**On February 1, 2022, the Company entered into a purchase and sale agreement to acquire additional interests in oil and gas properties located in Mountrail County, North Dakota for an aggregate purchase price of $240 million (before closing adjustments). Upon executing the agreement, the Company tendered a $12 million deposit which will be held in escrow until closing of the transaction. The transaction is anticipated to close in March 2022 and the Company plans to account for the transaction using the acquisition method of accounting.

Dividends**—**On February 8, 2022, the Company announced an inaugural quarterly dividend of $0.25 per share with the first dividend to be paid on March 15, 2022 to shareholders of record as of February 21, 2022.

SUPPLEMENTAL DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Oil and Gas Producing Activities

Net capitalized costs related to the Company's oil and gas producing activities were as follows (in thousands):

	Successor	
	December 31, 2021	December 31, 2020
Proved oil and gas properties	$ 2,034,533	$ 1,701,163
Unproved oil and gas properties	240,375	111,438
Accumulated depletion	(248,298)	(71,064)
Oil and gas properties, net	$ 2,026,610	$ 1,741,537

The Company's oil and gas activities for the periods presented were entirely within the United States. Costs incurred in oil and gas producing activities were as follows (in thousands):

	Successor		Predecessor	
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Year Ended December 31, 2019
Development [(1)]	$ 278,370	$ (6,773)	$ 241,795	$ 763,395
Proved property acquisition	197,104	4	146	-
Unproved property acquisition	104,198	163	346	6,281
Exploration	4,074	4,632	22,945	36,872
Total	$ 583,746	$ (1,974)	$ 265,232	$ 806,548

(1) Development costs include non-cash upward adjustments to oil and gas properties of $27 million and $57 million for 2021 and the 2020 Predecessor Period, respectively, which related to estimated future plugging and abandonment costs of the Company's oil and gas wells. Additionally, the 2020 Successor Period and the year ended December 31, 2019 (Predecessor) include non-cash downward adjustments of $31 million and $9 million, respectively, which related to estimated future plugging and abandonment costs of the Company's oil and gas wells.

Oil and Gas Reserve Quantities

For all years presented, the Company's independent petroleum engineers independently estimated all of the proved reserve quantities included in this Annual Report on Form 10-K. In connection with the external petroleum engineers performing their independent reserve estimations, Whiting furnishes them with the following information for their use in their evaluation: (i) technical support data, (ii) technical analysis of geologic and engineering support information, (iii) economic and production data, (iv) the Company's well ownership interests and (v) expected future development activity. The independent petroleum engineers, Netherland, Sewell & Associates, Inc., evaluated 100% of the Company's estimated proved reserve quantities and their related pre-tax future net cash flows as of December 31, 2021. Proved reserve estimates included herein conform to the definitions prescribed by the SEC. 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.

As of December 31, 2021, all of the Company's oil and gas reserves are attributable to properties within the United States. A summary of the Company's changes in quantities of proved oil and gas reserves for the periods presented are as follows:

	Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total (MBOE)
Proved reserves				
Balance—January 1, 2019 (Predecessor)	286,964	111,284	731,084	520,095
Extensions and discoveries	20,103	6,056	46,808	33,960
Purchases of minerals in place	(3,175)	(855)	(5,253)	(4,906)
Production	(29,811)	(7,596)	(50,483)	(45,820)
Revisions to previous estimates	(5,828)	(15,048)	17,886	(17,894)
Balance—December 31, 2019 (Predecessor)	268,253	93,841	740,042	485,435
Extensions and discoveries	12,616	2,627	17,306	18,127
Sales of minerals in place	(957)	(121)	(1,082)	(1,258)
Production	(22,130)	(6,626)	(44,007)	(36,091)
Revisions to previous estimates	(94,513)	(43,354)	(408,642)	(205,974)
Balance—December 31, 2020 (Successor)	163,269	46,367	303,617	260,239
Extensions and discoveries	12,720	3,898	22,001	20,285
Purchases of minerals in place	10,007	2,702	18,861	15,851
Sales of minerals in place	(6,434)	(1,551)	(16,113)	(10,670)
Production	(19,316)	(7,218)	(41,964)	(33,528)
Revisions to previous estimates	28,358	22,167	139,647	73,800
Balance—December 31, 2021 (Successor)	188,604	66,365	426,049	325,977
Proved developed reserves				
December 31, 2018 (Predecessor)	194,869	82,725	529,154	365,786
December 31, 2019 (Predecessor)	190,725	72,102	576,213	358,863
December 31, 2020 (Successor)	128,227	37,961	251,316	208,074
December 31, 2021 (Successor)	148,317	55,006	351,914	261,975
Proved undeveloped reserves				
December 31, 2018 (Predecessor)	92,095	28,559	201,930	154,309
December 31, 2019 (Predecessor)	77,528	21,739	163,829	126,572
December 31, 2020 (Successor)	35,042	8,406	52,301	52,165
December 31, 2021 (Successor)	40,287	11,359	74,135	64,002

Notable changes in proved reserves for the year ended December 31, 2021 included the following:

- *Extensions and discoveries.* In 2021, total extensions and discoveries of 20.3 MMBOE were primarily attributable to successful drilling in the Williston Basin. New wells drilled in this area as well as the PUD locations added as a result of drilling increased the Company's proved reserves.

- *Purchases of minerals in place.* Purchases of minerals in place totaled 15.9 MMBOE during 2021 and were primarily attributable to two acquisitions in the Williston Basin as further described in the "Acquisitions and Divestitures" footnote in the notes to the consolidated financial statements within Item 8 of this Annual Report on Form 10-K.

- *Sales of minerals in place.* Sales of minerals in place totaled 10.7 MMBOE during 2021 and were primarily attributable to the disposition of all of the Company's interests in producing assets and undeveloped acreage of the Company's Redtail field located in the Denver-Julesburg Basin of Weld County, Colorado as further described in the "Acquisitions and Divestitures" footnote in the notes to the consolidated financial statements within Item 8 of this Annual Report on Form 10-K.

- *Revisions to previous estimates.* In 2021, revisions to previous estimates increased proved developed and undeveloped reserves by a net amount of 73.8 MMBOE. Included in these revisions were (i) 70.1 MMBOE of upward adjustments resulting from higher crude oil, NGL and natural gas prices incorporated into the Company's reserve estimates at December 31, 2021 as compared to December 31, 2020, (ii) 12.8 MMBOE of upward adjustments primarily attributable to reservoir and engineering analysis and well performance across the Company's North Dakota and Montana assets, and (iii) 0.8 MMBOE of upward adjustments attributable to narrower differentials and stronger NGL yields. These upward adjustments were partially offset by 9.9 MMBOE of downward adjustments due to increased operating expenses.

Notable changes in proved reserves for the year ended December 31, 2020 included the following:

- *Extensions and discoveries.* In 2020, total extensions and discoveries of 18.1 MMBOE were primarily attributable to successful drilling in the Williston Basin. Both the new wells drilled in this area as well as the PUD locations added as a result of drilling increased the Company's proved reserves.

- *Sales of minerals in place.* Sales of minerals in place totaled 1.3 MMBOE during 2020 and were primarily attributable to the disposition of certain non-operated properties in North Dakota as further described in the "Acquisitions and Divestitures" footnote in the notes to the consolidated financial statements within Item 8 of this Annual Report on Form 10-K.

- *Revisions to previous estimates.* In 2020, revisions to previous estimates decreased proved developed and undeveloped reserves by a net amount of 206.0 MMBOE. Included in these revisions were 41.3 MMBOE of proved undeveloped reserve reductions due to changes in the Company's development plan. Of this 41.3 MMBOE, 34.8 MMBOE represents proved undeveloped reserves no longer expected to be developed within five years from their initial recognition and 6.5 MMBOE represents other development timing changes. As a result of the significant declines in commodity pricing the Company experienced in 2020 as well as its chapter 11 reorganization, the Company has moved toward a more disciplined capital development program focused on the highest-return projects and the generation of free cash flow, which resulted in a change in the timing of the Company's development plans related to PUD reserves in certain areas. These revisions do not represent the elimination of recoverable hydrocarbons physically in place, as they may be developed in the future. In addition, there were 114.3 MMBOE of downward adjustments primarily attributable to reservoir and engineering analysis and well performance across Whiting's assets in North Dakota, Montana and Colorado assets including: (i) 64.7 MMBOE of performance adjustments related to changes in gas-oil ratio estimates and oil estimates based on 2020 well performance data and subsequent reservoir and engineering analysis, (ii) 43.7 MMBOE of changes to lease operating cost estimates related to a change in the Company's process for modeling certain operating costs and higher operating costs experienced in 2020, and (iii) 5.9 MMBOE of other various revisions. Finally, there were 50.5 MMBOE of negative adjustments resulting from lower crude oil, NGL and natural gas prices incorporated into the Company's reserve estimates at December 31, 2020 as compared to December 31, 2019.

Notable changes in proved reserves for the year ended December 31, 2019 included the following:

- *Extensions and discoveries.* In 2019, total extensions and discoveries of 34.0 MMBOE were primarily attributable to successful drilling in the Williston Basin. Both the new wells drilled in this area as well as the PUD locations added as a result of drilling increased the Company's proved reserves.

- *Sales of minerals in place.* Sales of minerals in place totaled 4.9 MMBOE during 2019 and were primarily attributable to the disposition of certain non-operated properties in North Dakota as further described in the "Acquisitions and Divestitures" footnote in the notes to the consolidated financial statements within Item 8 of this Annual Report on Form 10-K.

- *Revisions to previous estimates.* In 2019, revisions to previous estimates decreased proved developed and undeveloped reserves by a net amount of 17.9 MMBOE. Included in this change were upward revisions of 48.0 MMBOE to proved undeveloped reserves primarily located in the Williston Basin in locations where the Company has significant development activity and past drilling success. Offsetting these upward revisions were: (i) 32.9 MMBOE of downward adjustments caused by lower crude oil, NGL and natural gas prices incorporated into the Company's reserve estimates at December 31, 2019 as compared to December 31, 2018, (ii) 19.3 MMBOE of downward adjustments primarily attributable to reservoir analysis and well performance across the Company's assets in North Dakota, Montana and Colorado and (iii) 13.7 MMBOE of proved undeveloped reserves no longer expected to be developed within five years from their initial recognition.

Revision of 2019 and 2020 Standardized Measure of Discounted Future Net Cash Flows

The Company has corrected certain errors in the unaudited Standardized Measure calculations previously reported in the supplemental disclosures to the Company's financial statements for the years ended December 31, 2020 and 2019. The Company has revised the line item for future development costs to include estimated costs related to property abandonment in accordance with FASB ASC 932-235-50-30, 50-31 and 55-6. This change also impacts the calculation of future income taxes and discount for each respective period. The tables below set forth the effect of these errors on the Standardized Measure calculations previously disclosed in the supplemental disclosures to the Company's financial statements for the years ended December 31, 2020 and 2019 (in thousands).

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	December 31, 2020			December 31, 2019		
	As Previously Reported	Change	As Revised	As Previously Reported	Change	As Revised
Future cash flows	$ 5,628,620	$ -	$ 5,628,620	$ 14,700,974	$ -	$ 14,700,974
Future production costs	(3,074,138)	-	(3,074,138)	(6,983,878)	-	(6,983,878)
Future development costs	(508,969)	(303,385)	(812,354)	(1,451,487)	(317,650)	(1,769,137)
Future income tax expense	(13,879)	13,879	-	(88,960)	10,680	(78,280)
Future net cash flows	2,031,634	(289,506)	1,742,128	6,176,649	(306,970)	5,869,679
10% annual discount for estimated timing of cash flows	(840,855)	170,704	(670,151)	(2,474,320)	253,375	(2,220,945)
Standardized measure of discounted future net cash flows	$ 1,190,779	$ (118,802)	$ 1,071,977	$ 3,702,329	$ (53,595)	$ 3,648,734

	Year Ended December 31, 2020			Year Ended December 31, 2019		
	As Previously Reported	Change	As Revised	As Previously Reported	Change	As Revised
Beginning of year	$ 3,702,329	$ (53,595)	$ 3,648,734	$ 5,206,110	$ (53,361)	$ 5,152,749
Sale of oil and gas produced, net of production costs	(404,495)	-	(404,495)	(1,063,167)	-	(1,063,167)
Sales of minerals in place	(8,539)	-	(8,539)	(52,456)	-	(52,456)
Net changes in prices and production costs	(2,061,696)	-	(2,061,696)	(1,681,530)	-	(1,681,530)
Extensions, discoveries and improved recoveries	123,073	-	123,073	234,782	-	234,782
Previously estimated development costs incurred during the period	197,960	-	197,960	455,236	-	455,236
Changes in estimated future development costs	632,468	(66,268)	566,200	(12,964)	20,910	7,946
Purchases of minerals in place	-	-	-	-	-	-
Revisions of previous quantity estimates	(1,398,437)	-	(1,398,437)	(191,329)	-	(191,329)
Net change in income taxes	37,883	6,420	44,303	287,036	(15,808)	271,228
Accretion of discount	370,233	(5,359)	364,874	520,611	(5,336)	515,275
End of year	$ 1,190,779	$ (118,802)	$ 1,071,977	$ 3,702,329	$ (53,595)	$ 3,648,734

The Company has assessed the materiality of these errors in accordance with the guidelines provided by the SEC under Staff Accounting Bulletin Topic 1M: *Materiality* and Staff Accounting Bulletin Topic 1N: *Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in the Current Year Financial Statements*. Based on this analysis, the Company has determined that these errors were not material to each of the years ended December 31, 2020 and 2019.

Standardized Measure of Discounted Future Net Cash Flows

The Standardized Measure relating to proved oil and gas reserves and changes in the Standardized Measure relating to proved oil and natural gas reserves were prepared in accordance with the provisions of FASB ASC Topic 932, *Extractive Activities—Oil and Gas*. Future cash inflows as of December 31, 2021, 2020 and 2019 were computed by applying average fiscal-year prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period ended December 31, 2021, 2020 and 2019, respectively) to estimated future production. Future production and development costs (which include future costs related to property abandonment) 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 year-end costs and assuming the 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, less the tax basis of properties involved. 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. This calculation does not necessarily result in an estimate of the fair value of the Company’s oil and gas properties.

The Standardized Measure relating to proved oil and natural gas reserves is as follows (in thousands):

	December 31,		
	2021	2020 [(1)]	2019 [(1)]
Future cash flows	$ 13,554,387	$ 5,628,620	$ 14,700,974
Future production costs	(5,040,334)	(3,074,138)	(6,983,878)
Future development costs	(864,049)	(812,354)	(1,769,137)
Future income tax expense	(1,241,224)	-	(78,280)
Future net cash flows	6,408,780	1,742,128	5,869,679
10% annual discount for estimated timing of cash flows	(2,729,490)	(670,151)	(2,220,945)
Standardized measure of discounted future net cash flows	$ 3,679,290	$ 1,071,977	$ 3,648,734

(1) As revised.

Future cash flows as shown above are reported without consideration for the effects of open hedge contracts at each period end. If the effects of hedging transactions were included in the computation, then undiscounted future cash inflows would have decreased by $151 million in 2021 and increased by $34 million in 2020, respectively. The effects of hedging transactions had no significant impact on undiscounted future cash inflows in 2019.

The changes in the Standardized Measure relating to proved oil and natural gas reserves are as follows (in thousands):

	Year Ended December 31,		
	2021	2020 [(1)]	2019 [(1)]
Beginning of year	$ 1,071,977	$ 3,648,734	$ 5,152,749
Sale of oil and gas produced, net of production costs	(1,128,837)	(404,495)	(1,063,167)
Sales of minerals in place	(150,660)	(8,539)	(52,456)
Net changes in prices and production costs	2,877,747	(2,061,696)	(1,681,530)
Extensions, discoveries and improved recoveries	286,422	123,073	234,782
Previously estimated development costs incurred during the period	163,740	197,960	455,236
Changes in estimated future development costs	(112,230)	566,200	7,946
Purchases of minerals in place	223,819	-	-
Revisions of previous quantity estimates	1,042,079	(1,398,437)	(191,329)
Net change in income taxes	(701,965)	44,303	271,228
Accretion of discount	107,198	364,874	515,275
End of year	$ 3,679,290	$ 1,071,977	$ 3,648,734

(1) As revised.

Future net revenues included in the Standardized Measure relating to proved oil and natural gas reserves incorporate calculated weighted average sales prices (inclusive of adjustments for quality and location) in effect at December 31, 2021, 2020 and 2019 as follows:

	Successor		Predecessor
	2021	2020	2019
Oil (per Bbl)	$ 61.94	$ 33.07	$ 50.89
NGLs (per Bbl)	$ 16.99	$ 5.10	$ 8.72
Natural Gas (per Mcf)	$ 1.75	$ (0.03)	$ 0.31

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Item 9. <u>Changes in and Disagreements with Accountants on Accounting and Financial Disclosure</u>

None.

Item 9A. <u>Controls and Procedures</u>

Evaluation of disclosure controls and procedures. In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), our management evaluated, with the participation of our President and Chief Executive Officer and our Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of the end of the year ended December 31, 2021. Based upon their evaluation of these disclosure controls and procedures, the President and Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures were effective as of December 31, 2021 to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting. The management of Whiting Petroleum Corporation and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Our internal control over financial reporting is 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.

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

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2021 using the criteria set forth in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management believes that, as of December 31, 2021, our internal control over financial reporting was effective based on those criteria.

The effectiveness of our internal control over financial reporting as of December 31, 2021 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein on the following page.

Changes in internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the quarter ended December 31, 2021 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Whiting Petroleum Corporation
Denver, Colorado

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Whiting Petroleum Corporation 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 February 23, 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 Annual Report on 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
February 23, 2022

Item 9B. <u>Other Information</u>

None.

Item 9C. <u>Disclosure Regarding Foreign Jurisdictions that Prevent Inspections</u>

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information included under the captions "Corporate Governance – Proposal 1 – Election of Directors", "Corporate Governance – Board Committee Information – Audit Committee" and "Share Ownership – Section 16(a) Beneficial Ownership Reporting Compliance" in our definitive Proxy Statement for Whiting Petroleum Corporation's 2022 Annual Meeting of Stockholders (the "Proxy Statement") is incorporated herein by reference. Information with respect to our executive officers appears in Part I of this Annual Report on Form 10-K.

We have adopted the Whiting Petroleum Corporation Code of Business Conduct and Ethics that applies to our directors, our President and Chief Executive Officer, our Executive Vice President Finance and Chief Financial Officer, our Vice President, Accounting and Controller and other persons performing similar functions. We have posted a copy of the Whiting Petroleum Corporation Code of Business Conduct and Ethics on our website at www.whiting.com. The Whiting Petroleum Corporation Code of Business Conduct and Ethics is also available in print to any stockholder who requests it in writing from the Corporate Secretary of Whiting Petroleum Corporation. We intend to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding amendments to, or waivers from, the Whiting Petroleum Corporation Code of Business Conduct and Ethics by posting such information on our website at www.whiting.com.

We are not including the information contained on our website as part of, or incorporating it by reference into, this report.

Item 11. Executive Compensation

The information required by this Item is included under the captions "Corporate Governance – Director Compensation" and "Executive Compensation" (other than "Executive Compensation – Proposal 2 – Advisory Vote on the Compensation of Our Named Executive Officers") in the Proxy Statement and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this Item with respect to security ownership of certain beneficial owners and management is included under the captions "Common Stock – Directors and Executive Officers" and "Common Stock Ownership – Certain Beneficial Owners" in the Proxy Statement and is incorporated herein by reference. The following table sets forth information with respect to compensation plans under which equity securities of Whiting Petroleum Corporation are authorized for issuance as of December 31, 2021.

Equity Compensation Plan Information

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in the first column)
Equity compensation plans approved by security holders (1)	-	$ N/A	3,034,539 (2)
Equity compensation plans not approved by security holders	-	N/A	-
Total	-	$ N/A	3,034,539 (2)

(1) The 2020 Equity Plan provides the authority to issue 4,035,885 shares of the Successor's common stock. Any shares forfeited under the 2020 Equity Plan will be available for future issuance under the 2020 Equity Plan. However, shares netted for tax withholding under the 2020 Equity Plan will be cancelled and will not be available for future issuance. As of December 31, 2021, 3,034,539 shares of common stock remained available for grant under the 2020 Equity Plan.

(2) Number of securities reduced by 795,881 shares of restricted stock units previously issued for which the restrictions have not lapsed.

Item 13. Certain Relationships, Related Transactions and Director Independence

The information required by this Item is included under the caption "Corporate Governance – Governance Information – Independence of Directors" and "Corporate Governance – Governance Information – Transactions with Related Persons" in the Proxy Statement and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

The information required by this Item is included under the caption "Audit Matters – Audit and Non-Audit Fees and Services" in the Proxy Statement and is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1. Financial statements – Refer to the Index to Consolidated Financial Statements included in Item 8 of this Form 10-K for a list of all financial statements filed as part of this report.

2. Financial statement schedules – All schedules are omitted since the required information is not present, or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the consolidated financial statements or the notes thereto.

3. Exhibits – The exhibits listed in the accompanying index to exhibits are filed as part of this Annual Report on Form 10-K.

(b) Exhibits

The exhibits listed in the accompanying exhibit index are filed (except where otherwise indicated) as part of this report.

Item 16. Form 10-K Summary

None.

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EXHIBIT INDEX

Exhibit Number	Exhibit Description
(2)	Joint Chapter 11 Plan of Reorganization of Whiting Petroleum Corporation and its Debtor Affiliates [Incorporated by reference to Exhibit A of the Order Confirming the Joint Chapter 11 Plan of Reorganization, filed as Exhibit 2 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on August 17, 2020 (File No. 001-31899)]
(3.1)	Amended and Restated Certificate of Incorporation of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 3.1 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on September 1, 2020 (File No. 001-31899)].
(3.2)	Second Amended and Restated By-laws of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 3.2 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on September 1, 2020 (File No. 001-31899)].
(4.1)	Description of Securities.
(10.1)	Credit Agreement dated as of September 1, 2020, by and among Whiting Petroleum Corporation, as parent guarantor, Whiting Oil and Gas Corporation, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders and other parties party thereto [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on September 1, 2020 (File No. 001-31899)].
(10.2)	First Amendment to Credit Agreement, dated as of June 7, 2021, among Whiting Oil and Gas Corporation as Borrower, its Parent Guarantor Whiting Petroleum Corporation, JPMorgan Chase Bank, N.A. as Administrative Agent and the lenders signatory thereto [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q filed on August 4, 2021 (File No. 001-31899)].
(10.3)	Second Amendment and Waiver to Credit Agreement, dated as of September 15, 2021, among Whiting Oil and Gas Corporation as Borrower, its Parent Guarantor Whiting Petroleum Corporation, JPMorgan Chase Bank, N.A. as Administrative Agent and the lenders signatory thereto [Incorporated by reference to Exhibit 10.2 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q filed on November 3, 2021 (File No. 001-31899)].
(10.4)*	Form of Indemnification Agreement for directors and officers of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008 (File No. 001-31899)].
(10.5)	Specimen Common Stock Certificate [Incorporated by reference to Exhibit 4 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on September 1, 2020 (File No. 001-31899)].
(10.6)	Series A Warrant Agreement dated as of September 1, 2020, by and among Whiting Petroleum Corporation, Computershare Inc. and Computershare Trust Company, N.A. [Incorporated by reference to Exhibit 10.2 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on September 1, 2020 (File No. 001-31899)].
(10.7)	Series B Warrant Agreement dated as of September 1, 2020, by and among Whiting Petroleum Corporation, Computershare Inc. and Computershare Trust Company, N.A. [Incorporated by reference to Exhibit 10.3 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on September 1, 2020 (File No. 001-31899)].
(10.8)*	Executive Employment and Severance Agreement, dated February 2, 2021, by and between Whiting Petroleum Corporation and Lynn A. Peterson [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on February 4, 2021 (File No. 001-31899)].
(10.9)*	Executive Employment and Severance Agreement, dated February 2, 2021, by and between Whiting Petroleum Corporation and James P. Henderson [Incorporated by reference to Exhibit 10.2 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on February 4, 2021 (File No. 001-31899)].
(10.10)*	Executive Employment Agreement and Severance Agreement, dated February 2, 2021, by and between Whiting Petroleum Corporation and Charles J. Rimer [Incorporated by reference to Exhibit 10.3 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on February 4, 2021 (File No. 001-31899)].
(10.11)*	Form of Executive Employment Agreement and Severance Agreement for executive officers of Whiting Petroleum Corporation other than Lynn A. Peterson, James P. Henderson and Charles J. Rimer [Incorporated by reference to Exhibit 10.20 to Whiting Petroleum Corporation's Annual Report on Form 10-K filed on February 24, 2021 (File No. 001-31899)].
(10.12)*	Whiting Petroleum Corporation 2020 Equity Incentive Plan [Incorporated by reference to Exhibit 10.4 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on September 1, 2020 (File No. 001-31899)].
(10.13)*	Form of Restricted Stock Unit Award Agreement (Officer Time Vesting - grants prior to February 2, 2021) pursuant to the Whiting Petroleum Corporation 2020 Equity Incentive Plan [Incorporated by reference to Exhibit 10.13 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q filed on November 5, 2020 (File No. 001-31899)].
(10.14)*	Form of Restricted Stock Unit Award Agreement (Officer Stock Price Performance Vesting) pursuant to the Whiting Petroleum Corporation 2020 Equity Incentive Plan [Incorporated by reference to Exhibit 10.14 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q filed on November 5, 2020 (File No. 001-31899)].
(10.15)*	Form of Restricted Stock Unit Award Agreement (Non-Employee Director) pursuant to the Whiting Petroleum Corporation 2020 Equity Incentive Plan [Incorporated by reference to Exhibit 10.15 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q filed on November 5, 2020 (File No. 001-31899)].

Exhibit Number	Exhibit Description
(10.16)*	Form of Performance Stock Unit Award Agreement pursuant to the Whiting Petroleum Corporation 2020 Equity Incentive Plan [Incorporated by reference to Exhibit 10.4 to Whiting Petroleum Corporation's Current Report on Form 8-K filed February 4, 2021 (File No. 001-31899)].
(10.17)*	Form of Restricted Stock Award Agreement (Extended Vesting) pursuant to the Whiting Petroleum Corporation 2020 Equity Incentive Plan [Incorporated by reference to Exhibit 10.5 to Whiting Petroleum Corporation's Current Report on Form 8-K filed February 4, 2021 (File No. 001-31899)].
(10.18)*	Form of Restricted Stock Unit Award Agreement (Officer Time Vesting – grants on or after February 2, 2021) pursuant to the Whiting Petroleum Corporation 2020 Equity Incentive Plan [Incorporated by reference to Exhibit 10.6 to Whiting Petroleum Corporation's Current Report on Form 8-K filed February 4, 2021 (File No. 001-31899)].
(21)	Significant Subsidiaries of Whiting Petroleum Corporation.
(23.1)	Consent of Deloitte & Touche LLP.
(23.2)	Consent of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers.
(31.1)	Certification by the President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	Written Statement of the President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
(32.2)	Written Statement of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
(99.1)	Report of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers relating to Total Proved Reserves, dated January 28, 2022.
(99.2)	Order Confirming Joint Chapter 11 Plan of Reorganization of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 99.1 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on August 17, 2020 (File No. 001-31899)].
(101)	The following materials from Whiting Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2021 are filed herewith, formatted in iXBRL (Inline Extensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Statements of Equity, and (v) Notes to Consolidated Financial Statements. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the iXBRL document.
(104)	Cover Page Interactive Data File (formatted as Inline XBRL) – The cover page interactive data file does not appear in the interactive data file because its XBRL tags are embedded within the iXBRL document.

* A management contract or compensatory plan or arrangement.

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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, on this 23rd day of February, 2022.

WHITING PETROLEUM CORPORATION

By /s/ Lynn A. Peterson
Lynn A. Peterson
President and Chief Executive Officer

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

Signature	Title	Date
/s/ Lynn A. Peterson Lynn A. Peterson	President and Chief Executive Officer (Principal Executive Officer)	February 23, 2022
/s/ James P. Henderson James P. Henderson	Executive Vice President Finance and Chief Financial Officer (Principal Financial Officer)	February 23, 2022
/s/ Sirikka R. Lohoefener Sirikka R. Lohoefener	Vice President, Accounting and Controller (Principal Accounting Officer)	February 23, 2022
/s/ Kevin S. McCarthy Kevin S. McCarthy	Chairman of the Board	February 23, 2022
/s/ Janet L. Carrig Janet L. Carrig	Director	February 23, 2022
/s/ Susan M. Cunningham Susan M. Cunningham	Director	February 23, 2022
/s/ Paul J. Korus Paul J. Korus	Director	February 23, 2022
/s/ Daniel J. Rice IV Daniel J. Rice	Director	February 23, 2022
/s/ Anne Taylor Anne Taylor	Director	February 23, 2022