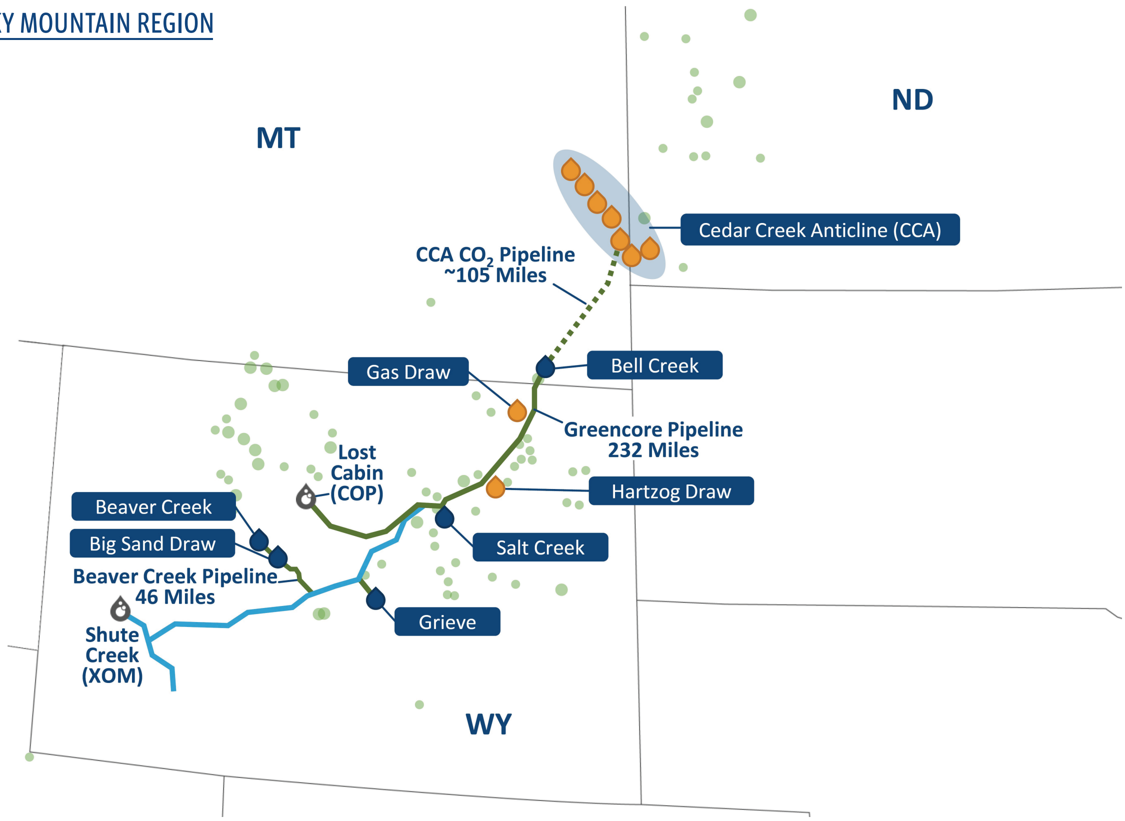
Denbury

2020 | **ANNUAL** REPORT

OPERATING AREAS

ROCKY MOUNTAIN REGION



GULF COAST REGION

- Denbury Operated CO_2 Pipelines
- Denbury Planned CO_2 Pipelines
- CO_2 Pipelines Owned by Others
- Fields Owned by Others – CO_2 EOR Candidates
- Denbury Owned Fields – Current CO_2 Floods
- Denbury Owned Fields – Potential CO_2 Floods
- Naturally-Occurring CO_2 Source
- Industrial CO_2 Sources Owned or Contracted

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

2020 FORM 10-K

(Mark One)

☑ **Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2020
OR

☐ **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from _________ to________

Commission file number: 001-12935

DENBURY INC.
(Exact name of Registrant as specified in its charter)

Delaware	**20-0467835**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
5851 Legacy Circle,	
Plano, TX	**75024**
(Address of principal executive offices)	*(Zip Code)*
Registrant's telephone number, including area code:	**(972) 673-2000**

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

Title of Each Class:	Trading Symbol:	Name of Each Exchange on Which Registered:
Common Stock $.001 Par Value	DEN	New York Stock Exchange

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 (§232.405 of this chapter) of Regulation S-T 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 12-b2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐ Smaller reporting company ☑ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

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

The aggregate market value of the registrant's common stock held by non-affiliates, based on the closing price of the registrant's common stock as of the last business day of the registrant's most recently completed second fiscal quarter was $138,886,832.

The number of shares outstanding of the registrant's Common Stock as of January 31, 2021, was 49,999,999.

DOCUMENTS INCORPORATED BY REFERENCE

Document:	**Incorporated as to:**
1. Notice and Proxy Statement for the Annual Meeting of Stockholders to be held May 26, 2021.	1. Part III, Items 10, 11, 12, 13, 14

Denbury Inc.

2020 Annual Report on Form 10-K
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Denbury Inc.

Glossary and Selected Abbreviations

Bbl	One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.
Bbls/d	Barrels of oil or other liquid hydrocarbons produced per day.
Bcf	One billion cubic feet of natural gas or CO_2.
BOE	One barrel of oil equivalent, using the ratio of one barrel of crude oil, condensate or natural gas liquids to 6 Mcf of natural gas.
BOE/d	BOEs produced per day.
Btu	British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit (°F).
CCUS	Carbon Capture, Use, and Storage.
CO_2	Carbon dioxide.
EOR	Enhanced oil recovery. In the context of our oil production, EOR is also referred to as tertiary recovery. Primary types of EOR include thermal, gas injection (such as natural gas, nitrogen, or CO_2) and chemical injection (such as the use of polymers).
Finding and development costs	The average cost per BOE to find and develop proved reserves during a given period. It is calculated by dividing (a) costs, which include the sum of (i) the total acquisition, exploration and development costs incurred during the period plus (ii) future development and abandonment costs related to the specified property or group of properties, by (b) the sum of (i) the change in total proved reserves during the period plus (ii) total production during that period.
GAAP	Accounting principles generally accepted in the United States of America.
MBbls	One thousand barrels of crude oil or other liquid hydrocarbons.
MBOE	One thousand BOEs.
Mcf	One thousand cubic feet of natural gas or CO_2 at a temperature base of 60 degrees Fahrenheit (°F) and at the legal pressure base (14.65 to 15.025 pounds per square inch absolute) of the state or area in which the reserves are located or sales are made.
Mcf/d	One thousand cubic feet of natural gas or CO_2 per day.
MMBOE	One million BOEs.
MMBtu	One million Btus.
MMcf	One million cubic feet of natural gas or CO_2.
MMcf/d	One million cubic feet of natural gas or CO_2 produced per day.
Noncash fair value gains (losses) on commodity derivatives	The net change during the period in the fair market value of commodity derivative positions. Noncash fair value gains (losses) on commodity derivatives is a non-GAAP measure and makes up only a portion of "Commodity derivatives expense (income)" in the Consolidated Statements of Operations, which also includes the impact of settlements on commodity derivatives during the period. Its use is further discussed in *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Financial and Operating Results Tables*.
NYMEX	The New York Mercantile Exchange. In the context of prices received for oil and natural gas, NYMEX prices represent the West Texas Intermediate benchmark price for crude oil and Henry Hub benchmark price for natural gas.
Probable Reserves*	Reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.
Proved Developed Reserves*	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved Reserves*	Reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved Undeveloped Reserves*	Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells, in each case where a relatively major expenditure is required.
PV-10 Value	The estimated future gross revenue to be generated from the production of proved reserves, net of estimated future production, development and abandonment costs, and before income taxes, discounted to a present value using an annual discount rate of 10%. PV-10 Values were prepared using average hydrocarbon prices equal to the unweighted arithmetic average of hydrocarbon prices on the first day of each month within the 12-month period preceding the reporting date. PV-10 Value is a non-GAAP measure and does not purport to represent the fair value of our oil and natural gas reserves; its use is further discussed in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Non-GAAP Financial Measure and Reconciliation*.
Tcf	One trillion cubic feet of natural gas or CO_2.
Tertiary Recovery	A term used to represent techniques for extracting incremental oil out of existing oil fields (as opposed to primary and secondary recovery or "non-tertiary" recovery). See also "EOR."

* This definition is an abbreviated version of the complete definition set forth in Rule 4-10(a) of Regulation S-X. For the complete definition see:
http://www.ecfr.gov/cgi-bin/text-idx?SID=2d916841db86d079fa060fa63b08d34e&mc=true&node=se17.3.210_14_610&rgn=div8.

PART I

Item 1. Business and Properties

GENERAL

Denbury Inc., a Delaware corporation, is an independent energy company with 143.1 MMBOE of estimated proved oil and natural gas reserves as of December 31, 2020, of which 98% is oil. Our operations are focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. The Company is differentiated by its focus on CO_2 EOR and the emerging CCUS industry, supported by the Company's CO_2 EOR technical and operational expertise and its extensive CO_2 pipeline infrastructure. The utilization of captured industrial-sourced CO_2 in EOR significantly reduces the carbon footprint of the oil that Denbury produces, underpinning the Company's goal to fully offset its Scope 1, 2, and 3 CO_2 emissions within the decade. Throughout this Annual Report on Form 10-K ("Form 10-K") we use the terms "Denbury," "Company," "we," "our" and "us" to refer to Denbury Inc. and, as the context may require, its subsidiaries.

As part of our corporate strategy, we are committed to creating long-term value for our shareholders through the following key principles:

- target specific regions where we either have, or believe we can create, a competitive advantage as a result of our ownership or use of CO_2 reserves, oil fields and CO_2 infrastructure;
- increase the value of our assets through applying our technical expertise in CO_2 tertiary recovery, together with a combination of other exploration, development, exploitation and marketing skills and practices;
- seek to expand the use of industrial-sourced CO_2 in our tertiary recovery operations, with an ultimate objective of producing oil with a negative carbon footprint;
- leverage our extensive CO_2 pipeline assets and CO_2 EOR expertise to expand our operations and leadership position in the emerging CCUS industry;
- acquire properties that give us a majority working interest and operational control or where we believe we can ultimately obtain it;
- maximize the value and cash flow generated from our operations by increasing production and reserves while controlling costs;
- optimize the timing and allocation of capital among our investment opportunities to maximize the rates of return on our investments;
- exercise financial discipline and maintain a strong balance sheet; and
- attract and maintain a highly competitive team of experienced and incentivized personnel.

As further described in *Emergence from Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code* below, Denbury Inc. became the successor reporting company (the "Successor") of Denbury Resources Inc. (the "Predecessor") upon the Predecessor's emergence from bankruptcy on September 18, 2020. On September 18, 2020, Denbury filed the Third Restated Certificate of Incorporation with the Delaware Secretary of State to effect a change of the Company's corporate name from Denbury Resources Inc. to Denbury Inc. On September 21, 2020, the Successor's new common stock commenced trading on the New York Stock Exchange under the ticker symbol DEN, as distinguished from, Denbury Resources Inc.'s common stock having been publicly traded on the New York Stock Exchange since 1997. Our corporate headquarters is located at 5851 Legacy Circle, Plano, Texas 75024, and our phone number is 972-673-2000. We make our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports, filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, available free of charge on or through our website, www.denbury.com, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission ("SEC"). The SEC also maintains a website, http://www.sec.gov, which contains periodic reports on Forms 8-K, 10-Q and 10-K filed with the SEC, along with other reports, proxy and information statements and other information filed by Denbury.

Emergence from Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code

On July 30, 2020 (the "Petition Date"), Denbury Resources Inc. and its subsidiaries filed petitions for reorganization in a "prepackaged" voluntary bankruptcy (the "Chapter 11 Restructuring") under chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court") under the caption "*In re Denbury Resources Inc., et al.*, Case No. 20-33801". On September 2, 2020, the Bankruptcy Court entered an order (the

"Confirmation Order") confirming the chapter 11 plan of reorganization (the "Plan") and approving the Disclosure Statement, and on September 18, 2020 (the "Emergence Date"), the Plan became effective in accordance with its terms and the Company emerged from the Chapter 11 bankruptcy proceedings. Key accomplishments of the Chapter 11 Restructuring included the following:

- Adopted an amended and restated certificate of incorporation and bylaws with authorized capitalization of 250,000,000 shares of common stock, par value $0.001 per share, of Denbury (the "New Common Stock") and 50,000,000 shares of preferred stock, par value $0.001 per share;
- Cancelled all outstanding senior secured second lien notes, convertible senior notes, and senior subordinated notes issued by the Predecessor. In accordance with the Plan, claims against and interests in the Predecessor were treated as follows:
    - Holders of senior secured second lien notes claims received their pro rata share of 47,499,999 shares representing 95% of the New Common Stock issued on the Emergence Date, subject to dilution on account of warrants and a management incentive plan;
    - Holders of convertible senior notes claims received their pro rata share of (a) 2,500,000 shares representing 5% of the New Common Stock issued on the Emergence Date, subject to dilution on account of warrants and a management incentive plan and (b) 100% of the series A warrants (see below), reflecting up to a maximum of 5% ownership stake in the reorganized company's equity interests;
    - Holders of subordinated notes claims received their pro rata share of 54.55% of the series B warrants (see below), reflecting up to a maximum of 3% of the reorganized company's equity interests after giving effect to the exercise of the series A warrants;
    - Holders of existing equity interests received their pro rata share of 45.45% of the series B warrants (see below), reflecting up to a maximum of 2.5% of the reorganized company's equity interests after giving effect to the exercise of the series A warrants;
    - Issued 2,631,579 five-year series A warrants at an exercise price of $32.59 per share to former holders of the Predecessor's convertible senior notes and 2,894,740 three-year series B warrants at an exercise price of $35.41 per share to former holders of the Predecessor's senior subordinated notes and Predecessor's equity interests; and
    - Holders of general unsecured claims received payment in full in cash, reimbursement, or such other treatment rendering such general unsecured claim unimpaired.
- Reduced ongoing annual interest expense by approximately $165 million, significantly lowering our cash flow breakeven level;
- Established a new $575 million senior secured bank credit facility with $482.0 million of availability at December 31, 2020 after outstanding letters of credit; and
- Appointed a new board of directors (the "Board") consisting of four new independent members: Anthony Abate, Caroline Angoorly, Brett Wiggs and James N. "Jim" Chapman, and three continuing members: Dr. Kevin O. Meyers (Chairman of the Board), Lynn A. Peterson and Chris Kendall, Denbury's President and Chief Executive Officer.

For more information on the Chapter 11 Restructuring and related matters, refer to Note 1, *Nature of Operations and Summary of Significant Accounting Policies – Emergence from Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code*, and Note 8, *Long-Term Debt*, to the consolidated financial statements.

Fresh Start Accounting

Upon emergence from bankruptcy, we met the criteria and were required to adopt fresh start accounting in accordance with Financial Accounting Standards Board Codification ("FASC") Topic 852, *Reorganizations*, which on the Emergence Date resulted in a new entity, the Successor, for financial reporting purposes, with no beginning retained earnings or deficit as of the fresh start reporting date. References to "Successor" relate to the financial position and results of operations of the Company subsequent to the Company's emergence from bankruptcy on September 18, 2020, and references to "Predecessor" relate to the financial position and results of operations of the Company prior to, and including, September 18, 2020. In order to assist investors in understanding the comparability of our financial results for the applicable periods, we have provided certain comparative analysis on a combined basis, which management believes provides meaningful information to assist investors in understanding our financial results for the applicable period, but should not be considered in isolation, as a substitute for, or more meaningful than, independent results of the Predecessor and Successor periods for the year reported in accordance with GAAP.

Fresh start accounting requires that new fair values be established for the Company's assets, liabilities and equity as of the date of emergence from bankruptcy, September 18, 2020, and therefore certain values and operational results of the consolidated financial statements subsequent to September 18, 2020 are not comparable to the Company's consolidated financial statements prior to, and including September 18, 2020, principally due to the Emergence Date re-evaluation of the fair value of our oil and natural gas properties, CO_2 properties, and pipelines, together with the conversion of over $2 billion of previously outstanding debt into new common stock and/or warrants in the Successor. The reorganization value derived from the range of enterprise values associated with the Plan was allocated to the Company's identifiable tangible and intangible assets and liabilities based on their fair values. The Emergence Date fair values of the Successor's assets and liabilities differ materially from their recorded values as reflected on the historical balance sheet of the Predecessor and may materially affect our results of operations in Successor reporting periods.

Impact of the COVID-19 Pandemic

In March 2020, the World Health Organization declared the ongoing COVID-19 coronavirus ("COVID-19") outbreak a pandemic, and the President of the United States declared the COVID-19 pandemic a national emergency. The COVID-19 pandemic has caused a rapid and precipitous drop in oil demand, which worsened an already deteriorated oil market that followed the early-March 2020 failure by the group of oil producing nations known as OPEC+ to reach an agreement over proposed oil production cuts. Uncertainty about the duration of the COVID-19 pandemic and its resulting economic consequences has resulted in abnormally high worldwide inventories of produced oil. While oil prices as of mid-February 2021 have improved to the low-$60s per barrel, which is significantly higher than the low points experienced during the second quarter of 2020, the concerns and uncertainties around the balance of supply and demand for oil are expected to continue for some time. Because the realized oil prices we received during 2020 were significantly reduced, our operating cash flow and liquidity were adversely affected.

2020 BUSINESS DEVELOPMENTS

Since our production is 97% oil, oil prices generally constitute the single largest variable in our operating results. Over the last several years, NYMEX oil prices have been extremely volatile, declining from a three-year peak of $76 per Bbl in October 2018 to lows averaging $17 per Bbl in April 2020 due to the significant interruption in worldwide economic activity and reduction in oil demand amid the COVID-19 pandemic, plus OPEC supply pressures, before gradually increasing to an average of $47 per Bbl in December 2020. Throughout this time, we have focused primarily on preservation of cash and liquidity, together with cost reductions and debt management, rather than concentration on expansion and growth. Our 2020 key business developments included the following:

- Completed financial restructuring and emerged from Chapter 11 reorganization on September 18, 2020 with a strong balance sheet and liquidity position (refer to Note 1, *Nature of Operations and Summary of Significant Accounting Policies – Emergence from Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code*, and Note 8, *Long-Term Debt*, to the consolidated financial statements).

- Reduced our originally planned capital expenditures in March 2020, deferred the CO_2 pipeline extension to Cedar Creek Anticline and implementation of the enhanced oil recovery development project beyond 2020; implemented cost reduction measures including shutting down compressors, negotiating reductions with vendors, and delaying uneconomic well repairs and workovers.

- Restructured our CO_2 pipeline financing arrangements with Genesis Energy, L.P. ("Genesis"), whereby we (1) reacquired the NEJD pipeline system from Genesis in exchange for $70 million to be paid in four equal payments during 2021, representing full settlement of all remaining obligations under the NEJD secured financing lease; and (2) reacquired the Free State Pipeline from Genesis in exchange for a one-time payment of $22.5 million on October 30, 2020. As a result, we reduced debt by $25 million and lowered interest expense while maximizing flexibility for future CCUS operations on these lines.

- Closed a farm-down transaction in March 2020 for the sale of half of our nearly 100% working interest positions in four conventional southeast Texas oil fields (consisting of Webster, Thompson, Manvel and East Hastings) for $40 million net cash and a carried interest in ten wells to be drilled by the purchaser (the “Gulf Coast Working Interests Sale”).

- Continued the monetization of valuable surface land with no active oil and natural gas operations, including the sale of multiple parcels primarily around Houston, Texas in transactions totaling $29 million in 2020.

- Entered into an agreement in December 2020 to acquire a nearly 100% working interest (approximately 83% net revenue interest) in the Big Sand Draw and Beaver Creek oil fields located in Wyoming for $12 million cash, including surface facilities and a 46-mile CO_2 transportation pipeline to the acquired fields. The agreement provides for us to make two contingent cash payments of $4 million each in 2021 and 2022 if NYMEX WTI oil prices average at least $50 per Bbl during the respective calendar years. The acquisition closed on March 3, 2021.

- Settled the Riley Ridge helium supply contract claim with APMTG Helium, LLC for $52.1 million, which was previously accrued as a liability in our Consolidated Balance Sheets.

2021 BUSINESS OUTLOOK

Oil prices continued to strengthen during the first two months of 2021, reaching the low-$60s per barrel in mid-February. Considering the current oil price environment and strategic importance of the CO_2 flood at Cedar Creek Anticline (“CCA”), we plan to move forward in 2021 with the development of this significant long-term project. We expect to allocate approximately $150 million of capital in 2021 to this CCA development, consisting of approximately $100 million dedicated to the 105-mile extension of the Greencore CO_2 pipeline from Bell Creek to CCA, with the remainder dedicated to facilities, well work and field development at CCA. In total, we estimate that our total development capital expenditures in 2021, excluding acquisitions and capitalized interest, will be in a range of $250 million to $270 million. Based on current oil prices and the Company’s hedge positions, we estimate that our 2021 cash flows from operations will exceed our budgeted level of planned development capital expenditures. In addition to our 2021 planned development capital, we acquired the Big Sand Draw and Beaver Creek oil fields in Wyoming in early March 2021 for a cash purchase price of $12 million before closing adjustments. Also, we plan to settle the remaining debt obligation to Genesis for the NEJD CO_2 pipeline, with $70 million in payments to be made over the course of 2021. We expect to fulfill these remaining obligations from cash flow and borrowings under our bank credit facility. At December 31, 2020, we had $482 million of availability under our bank credit facility, which we believe is more than adequate to cover any near-term liquidity needs. To supplement our liquidity, we may seek other sources of funding for all or a portion of the CCA CO_2 Pipeline expenditure.

Based on our capital spending plans, we currently anticipate 2021 average daily production to be between 47,500 BOE/d and 51,500 BOE/d, including the Big Sand Draw and Beaver Creek working interests acquisition expected to close in early March 2021. Our anticipated 2021 production level compares to 2020 average continuing production of 50,957 BOE/d, after reduction for 2020 property divestitures.

HUMAN CAPITAL RESOURCES

Our employees are our greatest resource, and each individual helps shape Denbury into a unique and exceptional place to work. We recognize that our employees are crucial to Denbury’s future, and we care about our employees’ and their families’ well-being beyond the work environment. As of December 31, 2020, we had 657 employees, of whom 365 were employed in our field operations or at our field offices and 292 were employed at our headquarters in Plano, TX.

Workforce Health and Safety

We continuously seek to improve our health and safety performance by fostering a culture that prioritizes safe work, then ensuring that this culture is exemplified in all levels of leadership. We provide our employees with tools to succeed, including relevant and timely training, and we monitor our performance using established measurement statistics. Each year, Denbury establishes corporate goals specifically related to employee and contractor safety performance and monitors progress toward those goals throughout the year using performance metrics. Results are regularly reported to our Board of Directors, senior management and all employees to ensure accountability and to reinforce their importance. Two safety performance metrics Denbury closely monitors are the Total Recordable Incident Rate (“TRIR”) and the Significant Injury or Fatality Rate (“SIFR”), which also captures near misses that may not have resulted in an injury. As detailed in our

Corporate Responsibility Report available on our website at www.denbury.com under the "Responsibility" link, Denbury has set new record lows for TRIR over the last four consecutive years and our 2020 SIFR was our second lowest ever.

In March 2020, the World Health Organization declared the ongoing COVID-19 outbreak a pandemic, and the President of the United States declared the COVID-19 pandemic a national emergency. In response to the COVID-19 pandemic, we formed a COVID-19 task force comprised of members of senior management and other key employees. The task force developed a systematic, data-based approach to monitor national, state and local orders and guidelines related to the COVID-19 pandemic, established internal processes, training and communications, conducted contract tracing, and engaged a third-party medical consulting firm to identify and clear COVID-19 cases and exposures. Additionally, we provided voluntary COVID-19 testing for all employees and their dependents and ensured that necessary sanitation supplies are available at all Denbury offices and locations.

Compensation and Benefits

As part of our compensation philosophy, we believe that we must offer and maintain competitive compensation and benefit programs for our employees in order to attract and retain outstanding talent. In addition to competitive base wages, other programs include an annual bonus plan, long-term incentive plan, Company matched 401(k) plan, healthcare and insurance benefits, health savings and flexible spending accounts and employee assistance programs.

Diversity and Inclusion

We are committed to increasing diversity and fostering an inclusive work environment that supports the workforce and the communities where we operate. Denbury aims to ensure equal opportunity in recruitment, and we reach a pool of diverse candidates by utilizing a digital recruiting program that posts available employment opportunities to websites worldwide, several of which are specifically targeted to reach diverse candidates. In 2020, women and minorities accounted for 21% and 14% of our workforce, respectively, and 46% and 23% of our new hires, respectively.

Our diversity, equity and inclusion principles are also reflected in our employee training and policies. To foster a diverse and collaborative workplace, Denbury requires all employees to complete annual training to raise awareness and encourage diversity and inclusion. Each year, our employee training program includes courses related to diversity, anti-discrimination, and anti-harassment to help employees understand diversity, cultural differences, recognize unconscious bias, and increase collaboration. We continue to enhance our diversity, equity and inclusion policies which are guided by our Board and executive leadership team.

Talent Acquisition, Retention and Development

Our success depends to a significant degree upon our ability to hire, develop, and retain highly skilled and experienced personnel, including our executive officers as well as other key management and technical specialists, such as geologists, geophysicists, engineers and other oil and gas industry professionals. Denbury provides employees with many ways to expand their skills and advance their careers through training and development initiatives. We believe this is critical to each employee's professional growth and success, as well as to our success as a company.

Human Rights

Denbury is committed to protecting human rights in the workplace. This commitment includes respecting the dignity and worth of all individuals, encouraging all individuals to reach their full potential, encouraging the initiative of each employee, and providing equal opportunity for development to all employees. Specifically, Denbury recognizes its responsibility with regards to: workplace health and safety, the prohibition of forced and child labor, a workplace free from harassment or any form of discrimination, freedom of association, complying with all laws regarding hours and wages and employee privacy. Denbury respects international human rights principles and our commitments to human rights are guided by the United National Global Compact and the International Labor Organization's Declaration of Fundamental Principals and Rights at Work. Our Code of Conduct and Human Rights Policy require employees to report any suspected human rights abuses. Denbury's Human Rights Policy is available on our website at www.denbury.com under the "Responsibility" link.

ESTIMATED NET QUANTITIES OF PROVED OIL AND NATURAL GAS RESERVES AND PRESENT VALUE OF ESTIMATED FUTURE NET REVENUES

Oil and Natural Gas Reserve Estimates

DeGolyer and MacNaughton ("D&M") prepared estimates of our net proved oil and natural gas reserves as of December 31, 2020, 2019 and 2018 (see the summary of D&M's report as of December 31, 2020, included as an exhibit to this Form 10-K). These estimates of reserves were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices on the first day of each month within the 12-month period in accordance with rules and regulations of the SEC. These oil and natural gas reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties.

The following table provides estimated proved reserve information prepared by D&M as of December 31, 2020, 2019 and 2018, as well as PV-10 Values and Standardized Measures for each period. The Company's December 31, 2020 proved oil and natural gas reserve quantities and PV-10 Values declined significantly from December 31, 2019 due largely to the decrease in oil prices used in preparing the December 31, 2019 and 2020 reserve information, whereby the average NYMEX oil price used in estimating our proved reserves declined from $55.69 per Bbl at December 31, 2019, to $39.57 per Bbl at December 31, 2020. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control, which are further discussed in Item 1A, *Risk Factors – Estimating our reserves, production and future net cash flows is difficult to do with any certainty*. See also *Oil and Natural Gas Operations – Field Summary Table* and *Supplemental Oil and Natural Gas Disclosures (Unaudited)* to the consolidated financial statements for further discussion of reserve inputs and changes between periods.

	December 31,		
	2020	2019	2018
Estimated proved reserves			
Oil (MBbls)	140,499	226,133	255,042
Natural gas (MMcf)	15,604	24,334	43,008
Oil equivalent (MBOE)	143,100	230,189	262,210
Reserve volumes categories			
Proved developed producing			
Oil (MBbls)	123,802	178,538	200,852
Natural gas (MMcf)	14,132	21,627	39,562
Oil equivalent (MBOE)	126,158	182,143	207,446
Proved developed non-producing			
Oil (MBbls)	12,600	24,278	21,884
Natural gas (MMcf)	1,472	2,706	3,350
Oil equivalent (MBOE)	12,845	24,729	22,442
Proved undeveloped			
Oil (MBbls)	4,097	23,317	32,306
Natural gas (MMcf)	—	1	96
Oil equivalent (MBOE)	4,097	23,317	32,322
Percentage of total MBOE			
Proved developed producing	88 %	79 %	79 %
Proved developed non-producing	9 %	11 %	9 %
Proved undeveloped	3 %	10 %	12 %
Representative oil and natural gas prices(1)			
Oil (NYMEX price per Bbl)	$ 39.57	$ 55.69	$ 65.56
Natural gas (Henry Hub price per MMBtu)	1.99	2.58	3.10
Present values (in thousands)(2)			
Discounted estimated future net cash flows before income taxes (PV-10 Value)(3)	$ 703,080	$ 2,615,668	$ 4,025,139
Standardized measure of discounted estimated future net cash flows after income taxes ("Standardized Measure")	$ 654,734	$ 2,261,039	$ 3,351,385

(1) The reference prices were based on the arithmetic average of the first-day-of-the-month NYMEX commodity prices for each month during the respective year. These prices do not reflect adjustments for market differentials and transportation expenses by field that are utilized in the preparation of our reserve report to arrive at the appropriate net price we receive. See Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Financial and Operating Results Tables* for details of oil and natural gas prices received, both including and excluding the impact of derivative settlements.

(2) Determined based on the average first-day-of-the-month prices for each month, adjusted to prices received by field in accordance with standards set forth in the FASC. PV-10 Values and the Standardized Measure are significantly impacted by the oil prices we receive relative to NYMEX oil prices (our NYMEX oil price differential). The weighted-average oil price differentials utilized were \$3.73 per Bbl below representative NYMEX oil prices as of December 31, 2020, compared to \$0.14 per Bbl below NYMEX oil prices as of December 31, 2019, and \$0.24 per Bbl below NYMEX oil prices as of December 31, 2018.

(3) PV-10 Value is a non-GAAP measure and is different from the Standardized Measure in that PV-10 Value is a pre-tax number and the Standardized Measure is an after-tax number. See Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Non-GAAP Financial Measure and Reconciliation* for further discussion.

Our proved developed non-producing reserves primarily consist of (1) reserves within a proved tertiary flood in areas that have not yet experienced a response from CO_2 injection, (2) reserves that will be recovered from currently productive zones utilizing minor modifications to manage the flow of CO_2 or water within the reservoir, and (3) reserves that will be recovered through recompletions to other intervals above or below the currently producing interval.

As of December 31, 2020, our estimated proved undeveloped reserves totaled approximately 4.1 MMBOE, or approximately 3% of our estimated total proved reserves. Approximately 83% (3.4 MMBOE) of our proved undeveloped oil reserves relate to planned future development within our CO_2 tertiary operating fields. We generally consider the CO_2 tertiary proved undeveloped reserves to be lower risk than other proved undeveloped reserves that require drilling at locations offsetting existing production, because all of these proved undeveloped reserves are associated with tertiary recovery operations in fields and reservoirs that historically produced substantial volumes of oil under primary production. As of December 31, 2020, 3.2 MMBOE of our total proved undeveloped reserves are not scheduled to be developed within five years of initial booking, all of which are part of CO_2 EOR projects. We believe these reserves satisfy the conditions to be included as proved reserves because (1) we have established and continue to follow the previously adopted development plan for each of these projects; (2) we have significant ongoing development activities in each of these CO_2 EOR projects and (3) we have a historical record of completing the development of comparable long-term projects.

Our proved undeveloped reserves at December 31, 2020 were 19.2 MMBOE (82%) lower than at December 31, 2019. During 2020, we spent approximately \$10 million to convert 1.5 MMBOE of proved undeveloped reserves to proved developed reserves, primarily related to continued tertiary development activities at Oyster Bayou Field. The primary changes in our proved undeveloped reserves during 2020 were related to recognizing net downward revisions of our proved undeveloped reserves of 17.7 MMBOE, primarily the result of the significant decline in commodity prices between December 31, 2019 and 2020.

During 2020, we provided oil and natural gas reserve estimates for 2019 to the United States Energy Information Agency that were substantially the same as the reserve estimates included in our Form 10-K for the year ended December 31, 2019.

Internal Controls Over Reserve Estimates

Reserve information in this report is based on estimates prepared by D&M, independent petroleum engineers located in Dallas, Texas, utilizing data provided by our internal reservoir engineering team and is the responsibility of management. We rely on D&M's expertise to ensure that our reserve estimates are prepared in compliance with SEC rules and regulations and that appropriate geologic, petroleum engineering, and evaluation principles and techniques are applied in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of June 2019)". The person responsible for the preparation of the reserve report is a Senior Vice President and Division Manager of North America at D&M. He received a Bachelor of Science degree in Petroleum Engineering in 2003 from Istanbul Technical University and a Master's degree and Doctorate in Petroleum Engineering in 2005 and 2010, respectively, from Texas A&M University, and he has in excess of 10 years of experience in oil and gas reservoir studies and evaluations. Our Senior Vice President – Business Development and Technology is primarily responsible for overseeing the independent petroleum engineers during the process. Our Senior Vice President – Business Development and Technology has a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines and over 35 years of industry experience working with petroleum engineering and reserve estimates. D&M relies on various data provided by our internal reservoir engineering team in preparing its reserve estimates, including such items as oil and natural gas prices, ownership interests, production information, operating costs, planned capital expenditures and other technical data. Our internal reservoir engineering team consists of qualified petroleum engineers who maintain the Company's internal evaluation of reserves and compare the Company's information to the reserves prepared by D&M. Management is responsible for designing the internal control procedures used in the preparation of our oil and gas reserves, which include verification of data input into reserve forecasting and economics evaluation software, as well as multi-discipline management reviews. The internal reservoir engineering team reports directly to our Senior Vice President – Business Development and Technology. In addition, our Audit Committee of the Board of Directors oversees the qualifications, independence, performance and hiring of our independent petroleum engineers and reviews the final report and subsequent reporting of our oil and natural gas reserve estimates. The Chairman of the Board holds a Ph.D. in Chemical Engineering from the Massachusetts Institute of Technology and bachelor's degrees in Chemistry and Mathematics from Capital University in Ohio. He has more than 40 years of industry experience, with responsibilities including reserves preparation and approval.

CARBON CAPTURE, USE AND STORAGE

In addition to our oil and natural gas operations, our strategically located and extensive CO_2 pipeline infrastructure provide a meaningful opportunity to grow our business in the emerging CCUS industry. We believe that the assets and expertise required for CCUS are highly aligned with Denbury's existing CO_2 EOR operations, providing Denbury with an advantage, particularly in the Gulf Coast region, where our CO_2 infrastructure is located in close proximity to multiple large sources of industrial emissions. We also believe that supportive U.S. government policy and public pressure on industrial CO_2 emitters could provide strong incentives for these entities to capture their CO_2 emissions. In early January 2021, the U.S. Treasury and the IRS issued final regulations under Section 45Q on the expanded carbon capture tax credit, implementing a number of changes and clarifications to previously proposed regulations, including (1) simplifying the definition of carbon capture equipment; (2) allowing smaller carbon capture facilities to be aggregated for purposes of meeting minimum capture requirements; (3) reducing the tax credit recapture period to three years; and (4) extending the beginning construction date to January 1, 2026 for carbon capture projects. The tax credit structure provides the capturing parties a tax credit that escalates until 2026, when it reaches $35 per ton for CO_2 used in EOR operations and $50 per ton for CO_2 directly stored in geologic formations. CCUS is a proven technology with the potential for safe, long-term, deep underground containment of industrial-sourced CO_2, and we believe Denbury is well positioned to leverage our existing CO_2 pipeline infrastructure and EOR expertise to be a leader in this industry.

OIL AND NATURAL GAS OPERATIONS

Summary. Our oil and natural gas properties are concentrated in the Gulf Coast and Rocky Mountain regions of the United States. Currently our properties with proved and producing reserves in the Gulf Coast region are situated in Mississippi, Texas, and Louisiana, and in the Rocky Mountain region are situated in Montana, North Dakota and Wyoming. The Company is differentiated by its focus on CO_2 EOR and the emerging CCUS industry, supported by the Company's CO_2 EOR technical and operational expertise and its extensive CO_2 pipeline infrastructure. The utilization of captured industrial-sourced CO_2 in EOR significantly reduces the carbon footprint of the oil that Denbury produces, underpinning the Company's goal to fully offset its Scope 1, 2, and 3 CO_2 emissions within the decade. Our current portfolio of CO_2 EOR projects provides us significant oil production and reserve growth potential in the future, assuming crude oil prices are at levels that support the development of those projects.

We have been conducting and expanding EOR operations on our assets in the Gulf Coast region since 1999, and as a result, we currently have many more CO_2 EOR projects in this region than in the Rocky Mountain region. We began operations in the Rocky Mountain region in 2010 in connection with, and following, our merger with Encore Acquisition Company ("Encore"). In 2012, as part of a significant sale and exchange transaction with Exxon Mobil Corporation ("ExxonMobil"), we sold to ExxonMobil our Bakken area assets in North Dakota and Montana in exchange for (1) $1.3 billion in cash, (2) operating interests in Hartzog Draw and Webster fields in Wyoming and Texas, respectively, and (3) an overriding royalty interest equivalent to an approximate one-third ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field in Wyoming (the "Bakken Exchange Transaction"). In the Gulf Coast region, we own what is, to our knowledge, the region's only significant naturally occurring source of CO_2, and these large volumes of naturally occurring CO_2 give us a significant competitive advantage in this area. In addition to this naturally occurring CO_2 source, we utilize CO_2 captured from industrial sources which would otherwise be released into the atmosphere (sometimes referred to as anthropogenic, man-made or industrial-sourced CO_2) in our tertiary operations, including CO_2 from the LaBarge Field in

Wyoming, which is captured in conjunction with processing helium from the LaBarge Field gas stream at ExxonMobil's Shute Creek gas plant. These industrial sources of CO_2 help us recover additional oil from mature oil fields and, we believe, also provide an economical way to reduce atmospheric CO_2 emissions through the associated underground storage of CO_2 which incidentally occurs as part of our oil-producing EOR operations.

Field Summary Table. The following table provides a summary by field and region of selected proved oil and natural gas reserve information, including total proved reserve quantities as of December 31, 2020, and average daily production for 2020, all based on Denbury's net revenue interest ("NRI"). The reserve estimates presented were prepared by D&M, independent petroleum engineers located in Dallas, Texas. We serve as operator of nearly all of our significant properties, in which we also own most of the interests, although typically less than a 100% working interest, and a lesser NRI due to royalties and other burdens. For additional oil and natural gas reserves information, see *Estimated Net Quantities of Proved Oil and Natural Gas Reserves and Present Value of Estimated Future Net Revenues* above and *Supplemental Oil and Natural Gas Disclosures (Unaudited)* to the consolidated financial statements.

	Proved Reserves as of December 31, 2020[1]				2020 Average Daily Production		
	Oil (MBbls)	Natural Gas (MMcf)	MBOEs	% of Company Total MBOEs	Oil (Bbls/d)	Natural Gas (Mcf/d)	Average 2020 NRI
Tertiary oil and gas properties							
Gulf Coast region							
Delhi	8,540	—	8,540	6.0 %	3,419	—	57.8 %
Hastings	19,722	—	19,722	13.8 %	4,755	—	79.9 %
Heidelberg	14,217	—	14,217	9.9 %	4,297	—	81.0 %
Oyster Bayou	13,691	—	13,691	9.6 %	3,818	—	87.3 %
Tinsley	6,916	—	6,916	4.8 %	3,959	—	81.9 %
West Yellow Creek	135	—	135	0.1 %	668	—	36.8 %
Mature properties[2]	7,356	—	7,356	5.1 %	5,759	—	80.0 %
Total Gulf Coast region	70,577	—	70,577	49.3 %	26,675	—	75.9 %
Rocky Mountain region							
Bell Creek	9,616	—	9,616	6.7 %	5,518	—	84.7 %
Salt Creek	2,002	—	2,002	1.4 %	1,928	—	17.6 %
Grieve	—	—	—	— %	14	—	20.5 %
Total Rocky Mountain region	11,618	—	11,618	8.1 %	7,460	—	41.9 %
Total tertiary properties	82,195	—	82,195	57.4 %	34,135	—	64.6 %
Non-tertiary oil and gas properties							
Gulf Coast region							
Texas	10,481	5,548	11,406	8.0 %	2,729	2,313	58.4 %
Mississippi and other	1,245	7,926	2,566	1.8 %	347	2,071	7.9 %
Total Gulf Coast region	11,726	13,474	13,972	9.8 %	3,076	4,384	31.7 %
Rocky Mountain region							
Cedar Creek Anticline[3]	45,217	4	45,218	31.6 %	11,745	1,439	80.6 %
Other	1,361	2,126	1,715	1.2 %	681	2,095	64.7 %
Total Rocky Mountain region	46,578	2,130	46,933	32.8 %	12,426	3,534	79.4 %
Total non-tertiary properties	58,304	15,604	60,905	42.6 %	15,502	7,918	59.7 %
Total continuing properties	140,499	15,604	143,100	100.0 %	49,637	7,918	63.0 %
Property sales							
Property divestitures[4]	—	—	—	— %	191	20	
Company Total	140,499	15,604	143,100	100.0 %	49,828	7,938	

(1) Reserve estimates were prepared in accordance with FASC Topic 932, *Extractive Industries – Oil and Gas*, using the arithmetic averages of the first-day-of-the-month NYMEX commodity price for each month during 2020, which were \$39.57 per Bbl for crude oil and \$1.99 per MMBtu for natural gas.

(2) Mature properties include Brookhaven, Cranfield, Eucutta, Little Creek, Mallalieu, Martinville, McComb and Soso fields in Mississippi.

(3) The Cedar Creek Anticline consists of a series of 13 different operating areas.

(4) Includes non-tertiary production related to the March 2020 sale of 50% of our working interests in Webster, Thompson, Manvel, and East Hastings fields.

Enhanced Oil Recovery Overview. CO_2 used in EOR is one of the most efficient tertiary recovery mechanisms for producing crude oil. When injected under pressure into underground, oil-bearing rock formations, CO_2 acts somewhat like a solvent as it travels through the reservoir rock, mixing with and modifying the characteristics of the oil so it can be produced and sold. The terms "tertiary flood," "CO_2 flood" and "CO_2 EOR" are used interchangeably throughout this document.

While enhanced oil recovery projects utilizing CO_2 have been successfully performed by numerous oil and gas companies in a wide range of oil-bearing reservoirs in different oil-producing basins, we believe our investments, experience and acquired knowledge give us a strategic and competitive advantage in the areas in which we operate. We apply what we have learned and developed over the years to improve and increase sweep efficiency within the CO_2 EOR projects we operate.

We began our CO_2 operations in August 1999, when we acquired Little Creek Field, followed by our acquisition of Jackson Dome CO_2 reserves and the NEJD pipeline in 2001. Based upon our success at Little Creek and the ownership of the CO_2 reserves, we began to transition our capital spending and acquisition efforts to focus more heavily on CO_2 EOR and, over time, transformed our strategy to focus primarily on owning and operating oil fields that are well suited for CO_2 EOR projects. Prior to tertiary flooding, we strive to maximize the currently sizeable primary and secondary production from our prospective tertiary fields and from fields in which tertiary floods have commenced but still contain significant non-tertiary production. Our asset base today almost entirely consists of, or otherwise relates to, oil fields that we are currently flooding with CO_2 or plan to flood with CO_2 in the future, or assets that produce CO_2.

Our tertiary operations have grown so that (1) 57% of our proved reserves at December 31, 2020 are proved tertiary oil reserves; (2) 67% of our 2020 total production was related to tertiary oil operations (on a BOE basis); and (3) 59% of our 2020 capital expenditures (excluding acquisitions) were related to our tertiary oil operations. At year-end 2020, the proved oil reserves in our tertiary recovery oil fields had an estimated PV-10 Value of approximately \$449.9 million, or 64% of our total PV-10 Value. In addition, there are significant probable and possible reserves at several other fields for which tertiary operations are underway or planned.

Although the up-front cost of tertiary production infrastructure and time to construct pipelines and production facilities is greater than in primary oil recovery in most circumstances, we believe tertiary recovery has several favorable, offsetting and unique attributes, including (1) a lower exploration risk, as we are operating oil fields that have significant historical production and reservoir and geological data, (2) lower production decline rates than unconventional development, (3) reasonable return metrics at our anticipated long-term prices, (4) limited competition for this recovery method in our geographic regions and a strategic advantage due to our ownership of the CO_2 reserves and CO_2 pipeline infrastructure, (5) our EOR operations are generally less disruptive to new habitats in comparison to other oil and natural gas development because we further develop existing (as opposed to new) oil fields, and (6) through our oil-producing EOR operations, we concurrently store CO_2 captured from industrial sources in the same underground formations that previously trapped and stored oil and natural gas.

Tertiary Oil Properties

Gulf Coast Region

CO_2 Sources and Pipelines

Jackson Dome. Our primary Gulf Coast CO_2 source, Jackson Dome, located near Jackson, Mississippi, was discovered during the 1970s by oil and gas companies that were exploring for hydrocarbons. This large and relatively pure source of naturally occurring CO_2 (98% CO_2) is, to our knowledge, the only significant underground deposit of CO_2 in the United States east of the Mississippi River. Together with the related CO_2 pipeline infrastructure, Jackson Dome provides us a significant strategic advantage in the acquisition of properties in Mississippi, Louisiana and southeastern Texas that are well suited for CO_2 EOR.

We acquired Jackson Dome in February 2001 in a purchase that also gave us ownership and control of the NEJD CO_2 pipeline and provided us with a reliable supply of CO_2 at a reasonable and predictable cost for our Gulf Coast CO_2 tertiary recovery operations. Since February 2001, we have acquired and drilled numerous CO_2-producing wells, significantly increasing our estimated proved Gulf Coast CO_2 reserves from approximately 800 Bcf at the time of acquisition of Jackson Dome to approximately 4.6 Tcf as of December 31, 2020. The proved CO_2 reserve estimates are based on a gross (8/8ths) basis, of which our net revenue interest is approximately 3.7 Tcf, and is included in the evaluation of proved CO_2 reserves prepared by D&M, independent petroleum engineers. In discussing our available CO_2 reserves, we make reference to the gross amount of proved and probable reserves, as this is the amount that is available both for our own tertiary recovery programs and for industrial users who are customers of Denbury and others, as we are responsible for distributing the entire CO_2 production stream.

In addition to our proved reserves, we estimate that we have 910.1 Bcf, on a gross (8/8ths) basis, of probable CO_2 reserves at Jackson Dome. While the majority of these probable reserves are located in structures that have been drilled and tested, such reserves are still considered probable reserves because (1) the original well is plugged; (2) they are located in fault blocks that are immediately adjacent to fault blocks with proved reserves; or (3) they are reserves associated with increasing the ultimate recovery factor from our existing reservoirs with proved reserves. In addition, a significant portion of these probable reserves at Jackson Dome are located in undrilled structures where we have sufficient subsurface and seismic data indicating geophysical attributes that, coupled with our historically high drilling success rate, provide a reasonably high degree of certainty that CO_2 is present.

In addition to our drilling at Jackson Dome, we have the capability to expand our processing and dehydration capacities and install additional pipelines and/or pumping stations necessary to transport the CO_2 through our controlled pipeline network. We expect our current proved reserves of CO_2, coupled with a risked drilling program at Jackson Dome and CO_2 expected to be captured from industrial sources, to provide sufficient quantities of CO_2 for us to develop our proved and probable EOR reserves in the Gulf Coast region. In the future, we believe that once a CO_2 flood in a field reaches its productive economic limit, we could recycle a portion of the CO_2 that remains in that field's reservoir and utilize it for oil production in another field's tertiary flood.

In the Gulf Coast region, approximately 78% of our average daily CO_2 produced from Jackson Dome or captured from industrial sources in 2020 was used in our tertiary recovery operations, compared to 84% in 2019 and 83% in 2018, with the balance delivered to third-party industrial users. During 2020, we used an average of 358 MMcf/d of CO_2 (including CO_2 captured from industrial sources) for our tertiary activities.

Gulf Coast CO_2 Captured from Industrial Sources. In addition to our natural source of CO_2, we are currently party to two long-term contracts to purchase CO_2 from industrial plants. We have purchased CO_2 from an industrial facility in Port Arthur, Texas since 2012 and from an industrial facility in Geismar, Louisiana since 2013, which supplied an average of approximately 57 MMcf/d of CO_2 to our EOR operations during 2020. Additionally, we are in ongoing discussions with other parties that are planning to capture CO_2 from currently existing industrial facilities or proposed new industrial facilities near the Green Pipeline. In order to capture such volumes, we (or the plant owner) would need to install additional equipment, which includes, at a minimum, compression and dehydration facilities.

Gulf Coast CO_2 Pipelines. We acquired the 183-mile NEJD CO_2 pipeline that runs from Jackson Dome to near Donaldsonville, Louisiana, as part of the 2001 acquisition of our Jackson Dome CO_2 source. Since 2001, we have acquired or constructed nearly 750 miles of CO_2 pipelines in the Gulf Coast, and as of December 31, 2020, we own nearly 925 miles of CO_2 pipelines, which gives us the ability to deliver CO_2 throughout the Gulf Coast region. In addition to the NEJD CO_2 pipeline, the major pipelines in the Gulf Coast region are the Free State Pipeline (90 miles), Delta Pipeline (110 miles), Green Pipeline Texas (120 miles), and Green Pipeline Louisiana (200 miles). In late October 2020, we restructured our NEJD and Free State CO_2 pipeline agreements with Genesis (see *2020 Business Developments* above).

Completion of the Green Pipeline allowed for the first CO_2 injection into Hastings Field, located near Houston, Texas, in 2010, and gives us the ability to deliver CO_2 to oil fields all along the Gulf Coast from Baton Rouge, Louisiana, to Alvin, Texas. At the present time, most of the CO_2 flowing in the Green Pipeline is delivered from the Jackson Dome area, but also includes the CO_2 we are receiving from the industrial facilities in Port Arthur, Texas and Geismar, Louisiana, and we are currently transporting a third party's CO_2 for a fee to the sales point at Hastings Field. We currently have ample capacity within the Green Pipeline to handle additional volumes that may be required to develop our inventory of CO_2 EOR projects in this area, as well as to support the transportation of CO_2 for the emerging CCUS business.

Tertiary Properties with Tertiary Production and Proved Tertiary Reserves at December 31, 2020

Delhi Field. Delhi Field is located east of Monroe, Louisiana. In May 2006, we purchased our initial interest in Delhi for $50 million. We began well and facility development in 2008, began delivering CO_2 to the field in 2009 via the Delta Pipeline, which runs from Tinsley Field to Delhi Field, and first tertiary production occurred at Delhi Field in 2010. During 2016, we completed construction of a natural gas liquids extraction plant, which provides us with the ability to sell natural gas liquids from the produced stream, improve the efficiency of the CO_2 flood, and utilize extracted methane to power the plant and reduce field operating expenses. Production from Delhi Field in the fourth quarter of 2020 averaged 3,132 Bbls/d, compared to 4,085 Bbls/d in the fourth quarter of 2019.

Hastings Field. Hastings Field is located south of Houston, Texas. We acquired a majority interest in this field in February 2009 for $247 million. We initiated CO_2 injection in the West Hastings Unit during 2010 upon completion of the construction of the Green Pipeline. Due to the large vertical oil column that exists in the field, we are developing the Frio reservoir using dedicated CO_2 injection and producing wells for each of the major sand intervals. We began producing oil from our EOR operations at Hastings Field in 2012, and we booked initial proved tertiary reserves for the West Hastings Unit in 2012. The Company also has future plans for continued tertiary development of existing proved undeveloped reserves at the field. During the fourth quarter of 2020, tertiary production from Hastings Field averaged 4,598 Bbls/d, compared to 5,097 Bbls/d in the fourth quarter of 2019.

Heidelberg Field. Heidelberg Field is located in Mississippi off of the Free State Pipeline and consists of an East Unit and a West Unit. Construction of the CO_2 facility, connecting pipeline and well work commenced on the West Heidelberg Unit during 2008, with our first CO_2 injections into the Eutaw zone. Our first tertiary oil production occurred in 2009, and we began flooding the Christmas and Tuscaloosa zones in 2013 and 2014, respectively. During 2019, we expanded our tertiary flood of the Christmas zone and invested in non-tertiary behind pipe projects. During the fourth quarter of 2020, tertiary production at Heidelberg Field averaged 4,198 Bbls/d, compared to 4,409 Bbls/d in the fourth quarter of 2019.

Oyster Bayou Field. We acquired a majority interest in Oyster Bayou Field in 2007. The field is located in southeast Texas, east of Galveston Bay, and is somewhat unique when compared to our other CO_2 EOR projects because the field covers a relatively small area of 3,912 acres. We began CO_2 injections into Oyster Bayou Field in 2010, commenced tertiary production in 2011 from the Frio A-1 zone, and booked initial proved tertiary reserves for the field in 2012. In 2014, we completed development of the Frio A-2 zone, and we further expanded the A-2 flood and increased compression capacity during 2020. During the fourth quarter of 2020, tertiary production at Oyster Bayou Field averaged 3,880 Bbls/d, compared to 4,261 Bbls/d in the fourth quarter of 2019.

Tinsley Field. We acquired Tinsley Field in 2006. This Mississippi field was discovered and first developed in the 1930s and is separated by different fault blocks. As is the case with the majority of fields in Mississippi, Tinsley Field produces from multiple reservoirs. Our CO_2 enhanced oil recovery operations at Tinsley Field have thus far targeted the Woodruff formation, although there is additional potential in the Perry sandstone and other smaller reservoirs. We commenced tertiary oil production from Tinsley Field in 2008 and substantially completed development of the Woodruff formation during 2014. During the fourth quarter of 2020, tertiary oil production from the field averaged 3,654 Bbls/d, compared to 4,343 Bbls/d in the fourth quarter of 2019. Although production from Tinsley Field peaked in 2015 and is generally on decline, we continue to evaluate future potential investment opportunities in this field.

West Yellow Creek Field. We acquired an approximate 48% non-operated working interest in West Yellow Creek Field in Mississippi in March 2017 for approximately $16 million, a field in which the operator had previously invested significant capital converting the field to a CO_2 EOR flood. Under our arrangement with the operator, we supply CO_2 to the field for a fee. West Yellow Creek Field is in close proximity and analogous to Eucutta Field, a very successful CO_2 flood that we developed and continue to operate. We booked initial proved tertiary oil reserves at West Yellow Creek Field as of year-end 2017 and commenced tertiary production in early 2018. During the fourth quarter of 2020, tertiary oil production from the field averaged 614 Bbls/d, compared to 807 Bbls/d in the fourth quarter of 2019.

Mature properties. Mature properties include our longest-producing properties which are generally located along our NEJD CO_2 pipeline in southwest Mississippi and Louisiana and our Free State Pipeline in east Mississippi. This group of properties includes our initial CO_2 field, Little Creek, as well as several other fields (Brookhaven, Cranfield, Eucutta, Mallalieu, Martinville, McComb and Soso fields). These fields accounted for 17% of our total 2020 CO_2 EOR production and approximately 5% of our year-end proved reserves. These fields have been producing under CO_2 flood for more than a decade, and their production is generally declining, though we continue to evaluate future potential investment opportunities in these fields.

Potential Future Tertiary Properties with No Tertiary Production or Proved Tertiary Reserves at December 31, 2020

Webster Field. We acquired our interest in Webster Field in 2012 as part of the Bakken Exchange Transaction. The field is located southeast of Houston, Texas, approximately eight miles northeast of our Hastings Field which we are currently flooding with CO_2. At December 31, 2020, Webster Field had estimated proved non-tertiary reserves of approximately 1.3 MMBOE, net to our interest, all of which are proved developed. During the fourth quarter of 2020, non-tertiary production at Webster Field averaged 442 BOE/d, compared to 923 BOE/d in the fourth quarter of 2019. In March 2020, we sold half of our working interest in Webster Field as part of our Gulf Coast Working Interests Sale (see *Gulf Coast Working Interest Partner* below). Webster Field is geologically similar to our Hastings Field, producing oil from the Frio zone at similar depths; as a result, we believe it is well suited for CO_2 EOR. In 2014, we completed a nine-mile lateral between the Green Pipeline and Webster Field, which we plan will eventually deliver CO_2 to the field. Although we sold half of our working interest in Webster Field in 2020, we retained the right to execute a future CO_2 flood in this field, the timing of which is primarily dependent upon capital availability and priorities and future oil prices.

Conroe Field. Conroe Field, our largest potential tertiary flood in the Gulf Coast region, is located north of Houston, Texas. We acquired a majority interest in this field in 2009 for $271 million in cash and 11.6 million shares of Denbury common stock, for a total aggregate value of $439 million. Conroe Field had estimated proved non-tertiary reserves of approximately 7.8 MMBOE at December 31, 2020, net to our interest, all of which are proved developed. During the fourth quarter of 2020, non-tertiary production at Conroe Field averaged 1,624 BOE/d, compared to 1,861 BOE/d in the fourth quarter of 2019.

To initiate a CO_2 flood at Conroe Field, a pipeline must be constructed so that CO_2 can be delivered to the field. This pipeline, which is planned as an extension of our Green Pipeline, is preliminarily estimated to cover approximately 90 miles. The timing of the development of a CO_2 flood at Conroe Field is primarily dependent upon capital availability and priorities, future oil prices and pipeline construction.

In addition to the currently-producing oil-bearing formations at Conroe Field, we are evaluating exploitation opportunities in other formations. We currently do not have any additional wells planned for 2021 but continue to evaluate additional opportunities and plan to de-risk other areas of the field in the future.

Thompson Field. We acquired our interest in Thompson Field in June 2012 for $366 million. The field is located in Texas, approximately 18 miles west of our Hastings Field. Thompson Field had estimated proved non-tertiary reserves of approximately 1.7 MMBOE at December 31, 2020, net to our interest, all of which are proved developed. During the fourth quarter of 2020, non-tertiary production at Thompson Field averaged 455 BOE/d, compared to 1,008 BOE/d in the fourth quarter of 2019. In March 2020, we sold half of our working interest in Thompson Field as part of our Gulf Coast Working Interests Sale (see *Gulf Coast Working Interest Partner* below). Thompson Field is geologically similar to Hastings Field, producing oil from the Frio zone at similar depths, and we therefore believe it has CO_2 EOR potential. Under the terms of the Thompson Field acquisition agreement, after the initiation of CO_2 injection, the seller will retain approximately a 5% gross revenue interest (less severance taxes) once average monthly oil production exceeds 3,000 Bbls/d.

The timing of the development of a CO_2 flood at Thompson Field is primarily dependent upon capital availability and priorities and future oil prices.

Gulf Coast Working Interest Partner. In March 2020, we sold half of our nearly 100% working interest positions in four conventional southeast Texas oil fields (consisting of Webster, Thompson, Manvel and East Hastings) for $40 million net cash and a carried interest in ten wells to be drilled by the purchaser. Under the agreement, the purchaser is committed to funding 100% of the capital required to drill and complete an initial ten horizontal wells across the fields within 18 months after closing. On these initial ten wells, Denbury will receive a 6.25% overriding royalty interest prior to the combined payout of the wells in a specified field and subsequent to payout, Denbury will receive production revenues from, and bear the cost of, its 50% working interest in each well. As part of the agreement, we will retain 100% ownership of the future Webster Unit CO_2 flood, wherein (1) the purchaser may elect to participate in the future CO_2 flood through reimbursement to Denbury of the purchaser's working interest share of project costs incurred to date, or (2) if the purchaser declines to participate in the CO_2 flood, we have the right to repurchase the purchaser's working interest in Webster Field under a contractually agreed valuation mechanism.

Rocky Mountain Region

CO_2 Sources and Pipelines

LaBarge Field. We acquired an overriding royalty interest equivalent to an approximate one-third ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field in the fourth quarter of 2012 as part of the Bakken Exchange Transaction. LaBarge Field is located in southwestern Wyoming, and as of December 31, 2020, our interest in LaBarge Field consisted of approximately 1.1 Tcf of proved CO_2 reserves.

During 2020, we received an average of approximately 85 MMcf/d of CO_2 from the Shute Creek gas processing plant at LaBarge Field that we used in our Rocky Mountain region CO_2 floods. Based on current capacity, and subject to availability of CO_2, we currently expect our CO_2 volumes from Shute Creek to increase in future years. We pay ExxonMobil a fee to process and deliver the CO_2, which we use in our Rocky Mountain region CO_2 floods.

Other Rocky Mountain CO_2 Sources. We have a contract in place to receive all of the CO_2 from the ConocoPhillips-operated Lost Cabin gas plant in central Wyoming, which we estimate has the capability to provide us as much as 30 MMcf/d of CO_2 for use in our Rocky Mountain region CO_2 floods, although we did not receive any CO_2 volumes for the period May 2020 through December 2020. We currently estimate that our existing CO_2 sources, plus additional CO_2 from those or other CO_2 sources in the region, are sufficient to carry out our base Rocky Mountain region EOR development plans.

Rocky Mountain CO_2 Pipelines. The 20-inch Greencore pipeline in Wyoming is the first CO_2 pipeline we constructed in the Rocky Mountain region. We plan to use the pipeline as our trunk line in the Rocky Mountain region, eventually connecting our various Rocky Mountain region CO_2 sources to the Cedar Creek Anticline in eastern Montana and western North Dakota. The 232-mile pipeline begins at the ConocoPhillips-operated Lost Cabin gas plant in Wyoming and terminates at Bell Creek Field in Montana. We completed construction of the pipeline in 2012 and received our first CO_2 deliveries from the ConocoPhillips-operated Lost Cabin gas plant during 2013. During 2014, we completed construction of an interconnect between our Greencore pipeline and an existing third-party CO_2 pipeline in Wyoming, which enables us to transport CO_2 from LaBarge Field to our Bell Creek Field.

The CO_2 enhanced oil recovery development project at Cedar Creek Anticline requires a 105-mile extension of the Greencore CO_2 pipeline to CCA from Bell Creek Field. The capital outlay for the pipeline is projected to be approximately $150 million, of which we have incurred approximately $50 million through December 31, 2020 (see also *Cedar Creek Anticline CO_2 EOR Project* below for further discussion).

Tertiary Properties with Tertiary Production and Proved Tertiary Reserves at December 31, 2020

Bell Creek Field. We acquired our interest in Bell Creek Field in southeast Montana as part of the Encore merger in 2010. The oil-producing reservoir in Bell Creek Field is a sandstone reservoir with characteristics similar to those we have successfully flooded with CO_2 in the Gulf Coast region. During 2013, we began first CO_2 injections into Bell Creek Field, recorded our first tertiary oil production, and booked initial proved tertiary reserves. During 2018, we completed the phase five expansion at the field, and in April 2019, commenced CO_2 injection into phase six of the field development. Tertiary production during the fourth quarter of 2020 averaged 5,079 Bbls/d of oil, compared to 5,618 Bbls/d in the fourth quarter of 2019.

Grieve Field. Under a 2011 farm-in agreement, we obtained a 65% working interest in Grieve Field, located in Natrona County, Wyoming, in exchange for developing the Grieve Field CO_2 flood. During 2016, the Company and its joint venture partner in Grieve Field revised their development arrangement for the field so that our partner funded development of the facility and fieldwork in exchange for a 14% higher working interest and a disproportionate sharing of revenue from the first 2 million barrels of production. We commenced tertiary production from Grieve Field during the fourth quarter of 2018 and booked initial proved tertiary reserves during 2019. In October 2020, we foreclosed on the joint venture partner's interest, and we obtained record title to their interest in February 2021.

Salt Creek Field. We acquired our 23% non-operated working interest in Salt Creek Field in Wyoming for approximately $72 million in June 2017. Tertiary production during the fourth quarter of 2020 averaged 2,007 Bbls/d of oil, compared to 2,223 Bbls/d in the fourth quarter of 2019.

March 2021 Acquisition of Wyoming CO_2 EOR Fields

Wyoming CO_2 EOR Fields. In December 2020, we entered into an agreement to acquire a nearly 100% working interest (approximately 83% net revenue interest) in the Big Sand Draw and Beaver Creek oil fields located in Wyoming for $12 million cash, including surface facilities and a 46-mile CO_2 transportation pipeline to the acquired fields. The agreement provides for us to make two contingent cash payments of $4 million each in 2021 and 2022 if NYMEX WTI oil prices average at least $50 per Bbl during the respective calendar years. Net production from the acquired fields was approximately 2,800 BOE/d for the third quarter of 2020, of which approximately 85% was oil production. Based on December 1, 2020 oil and natural gas futures strip prices, net proved reserves for the acquired fields, which are 93% oil, were estimated at approximately 13.7 MMBOE, including 5.5 MMBOE of proved undeveloped reserves. The acquisition closed on March 3, 2021.

Future Tertiary Properties with No Tertiary Production or Proved Tertiary Reserves at December 31, 2020

Cedar Creek Anticline. CCA is the largest potential EOR property that we own and currently our largest producing property, contributing approximately 23% of our 2020 total production. Historical production from the property has primarily been from the Red River interval. The field is primarily located in Montana but extends over such a large area (approximately 126 miles) that it also extends into North Dakota. CCA is a series of 13 different operating areas on a common geological trend, each of which could be considered a field by itself. We acquired our initial interest in CCA as part of the Encore merger in 2010 and acquired additional interests from a wholly-owned subsidiary of ConocoPhillips in 2013 for $1.0 billion, adding 42.2 MMBOE of incremental proved reserves at that date. Production from CCA averaged 11,433 BOE/d during the fourth quarter of 2020, compared to production during the fourth quarter of 2019 of 13,730 BOE/d. The non-tertiary proved reserves associated with CCA were 45.2 MMBOE, net to our interest, as of December 31, 2020.

In addition to the Red River interval, CCA contains other oil-bearing intervals including Mission Canyon and Charles B. We began pursuing these additional exploitation opportunities in late 2017. We have drilled nine successful Mission Canyon exploitation wells and a successful initial test well in Cabin Creek's Charles B formation over the last few years. We continue to evaluate the Charles B formation and believe it has characteristics that would make it a good candidate for secondary or tertiary flooding.

Cedar Creek Anticline CO_2 EOR Project. CCA is located approximately 110 miles north of Bell Creek Field, and our current plan is to extend the Greencore pipeline to CCA by the end of 2021, with first CO_2 injection planned during the first half of 2022. During 2021, we plan to spend approximately $100 million to complete the 105-mile extension of the Greencore CO_2 pipeline and an additional $50 million on facilities, well work and field development to prepare both the Cedar Hills South Unit and East Lookout Butte for initial CO_2 injections in the Red River formation. First tertiary production is currently expected in the latter part of 2023, or approximately 18 to 24 months after first injection, with additional phases of development expected to target the Interlake, Stony Mountain and Red River formations at Cabin Creek Field.

Hartzog Draw Field. We acquired our interest in Hartzog Draw Field in 2012 as part of the Bakken Exchange Transaction. The field is located in the Powder River Basin of northeastern Wyoming, approximately 12 miles from our Greencore pipeline. Hartzog Draw Field had estimated proved reserves of approximately 1.7 MMBOE at December 31, 2020, net to our interest, 0.3 MMBOE of which relate to the natural gas producing Big George coal zone. During the fourth quarter of 2020, non-tertiary production averaged 955 BOE/d, compared to 1,172 BOE/d in the fourth quarter of 2019. Industry activity around this field has been increasing for the last several years, with several operators testing various formations such as the Turner, Niobrara, Shannon, Parkman and Mowry for potential development. We believe the oil reservoir characteristics of Hartzog Draw Field make it well suited for CO_2 EOR in the future. The timing of development of a CO_2 flood at Hartzog Draw Field is primarily dependent upon capital availability and priorities and future oil prices.

Other Non-Tertiary Oil Properties

Despite the majority of our oil and natural gas properties discussed above consisting of either existing or planned future tertiary floods, we also produce oil and natural gas from fields in both our Gulf Coast and Rocky Mountain regions that are either not amenable to EOR or from specific reservoirs (within an existing tertiary field) that are not amenable to EOR. For example, at Heidelberg Field, we produce natural gas from the Selma Chalk reservoir, which is separate from the Christmas and Eutaw reservoirs currently being flooded with CO_2. Continuing production from these other non-tertiary properties totaled 1,016 BOE/d during the fourth quarter of 2020, compared to 1,362 BOE/d during the fourth quarter of 2019.

OIL AND GAS ACREAGE, PRODUCTIVE WELLS AND DRILLING ACTIVITY

In the data below, “gross” represents the total acres or wells in which we own a working interest and “net” represents the gross acres or wells multiplied by our working interest percentage. For the wells that produce both oil and gas, the well is typically classified as an oil or natural gas well based on the ratio of oil to natural gas production.

Oil and Gas Acreage

The following table sets forth our acreage position at December 31, 2020:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast region	188,850	147,855	286,842	18,228	475,692	166,083
Rocky Mountain region	362,327	314,948	118,521	26,655	480,848	341,603
Total	551,177	462,803	405,363	44,883	956,540	507,686

The percentage of our net undeveloped acreage that is subject to expiration over the next three years, if not renewed, is approximately 10% in 2021, 6% in 2022 and 4% in 2023.

Productive Wells

The following table sets forth our gross and net productive oil and natural gas wells as of December 31, 2020:

	Producing Oil Wells		Producing Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated wells						
Gulf Coast region	1,041	913	125	116	1,166	1,029
Rocky Mountain region	872	833	268	186	1,140	1,019
Total	1,913	1,746	393	302	2,306	2,048
Non-operated wells						
Gulf Coast region	43	18	1	—	44	18
Rocky Mountain region	581	130	2	—	583	130
Total	624	148	3	—	627	148
Total wells						
Gulf Coast region	1,084	931	126	116	1,210	1,047
Rocky Mountain region	1,453	963	270	186	1,723	1,149
Total	2,537	1,894	396	302	2,933	2,196

Drilling Activity

The following table sets forth the results of our drilling activities over the last three years. As of December 31, 2020, we did not have any wells in progress.

	Year Ended December 31,					
	2020		2019		2018	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells(1)						
Productive(2)	—	—	1	1	2	2
Non-productive(3)	—	—	—	—	—	—
Development wells(1)						
Productive(2)	5	3	19	18	14	12
Non-productive(3)(4)	—	—	—	—	3	3
Total	5	3	20	19	19	17

(1) An exploratory well is 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. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well. A development well is a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(2) A productive well is an exploratory or development well drilled and completed during the year and found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

(3) A non-productive well is an exploratory or development well that is not a productive well.

(4) During 2019 and 2018, an additional 7 and 4 wells, respectively, were drilled for water or CO_2 injection purposes.

The following table summarizes sales volumes, sales prices and production cost information for our net oil and natural gas production for the years ended December 31, 2020, 2019 and 2018:

	Year Ended December 31,		
	2020	2019	2018
Net sales volume			
Gulf Coast region			
Oil (MBbls)	10,958	12,638	13,484
Natural gas (MMcf)	1,612	1,779	1,973
Total Gulf Coast region (MBOE)	11,227	12,935	13,813
Rocky Mountain region			
Oil (MBbls)	7,278	8,047	7,880
Natural gas (MMcf)	1,293	1,595	1,988
Total Rocky Mountain region (MBOE)	7,494	8,313	8,211
Total Company (MBOE)	18,721	21,248	22,024
Average sales prices – excluding impact of derivative settlements			
Gulf Coast region			
Oil (per Bbl)	$ 38.44	$ 60.32	$ 67.75
Natural gas (per Mcf)	1.98	2.49	3.16
Rocky Mountain region			
Oil (per Bbl)	$ 36.79	$ 55.02	$ 63.30
Natural gas (per Mcf)	0.77	1.57	2.01
Total Company			
Oil (per Bbl)	$ 37.78	$ 58.26	$ 66.11
Natural gas (per Mcf)	1.44	2.06	2.58
Average production cost (per BOE sold)(1)			
Gulf Coast region(2)	$ 18.20	$ 22.49	$ 22.22
Rocky Mountain region	19.63	22.40	22.27
Total Company(2)	18.78	22.46	22.24

(1) Excludes oil and natural gas ad valorem and production taxes.
(2) Production costs during 2020 include Delhi insurance reimbursements. If these amounts were excluded, production cost per BOE for the Gulf Coast region and total Company would have averaged $19.58 and $19.60, respectively, for the year ended December 31, 2020.

PRODUCTION AND UNIT PRICES

Further information regarding average production rates, unit sales prices and unit costs per BOE are set forth under Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Financial and Operating Results Tables*, included herein.

TITLE TO PROPERTIES

As is customary in the oil and natural gas industry, Denbury conducts a limited title examination at the time of its acquisition of properties or leasehold interests targeted for enhanced recovery, and curative work is performed with respect to significant defects on higher-value properties of the greatest significance. We believe that title to our oil and natural gas properties is good and defensible, subject only to such exceptions that we believe do not materially interfere with the use of such properties, including encumbrances, easements, restrictions and royalty, overriding royalty and other similar interests.

SIGNIFICANT OIL AND GAS PURCHASERS AND PRODUCT MARKETING

Oil and natural gas sales are made on a day-to-day basis or under short-term contracts at the current area market price. We would not expect the loss of any single purchaser to have a material adverse effect upon our operations; however, the loss of a large single purchaser could potentially reduce the competition for our oil and natural gas production, which in turn could negatively impact the prices we receive. For the Successor period September 19, 2020 through December 31, 2020, three purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (30%), Marathon Petroleum Corporation (13%) and Hunt Crude Oil Supply Company (12%), and for the Predecessor period January 1, 2020 through September 18, 2020, three purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (30%), Hunt Crude Oil Supply Company (12%) and Marathon Petroleum Corporation (12%). For the year ended December 31, 2019 (Predecessor), three purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (32%), Hunt Crude Oil Supply Company (11%) and Sunoco Inc. (11%). For the year ended December 31, 2018 (Predecessor), two purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (24%) and Hunt Crude Oil Supply Company (10%).

Our ability to market oil and natural gas depends on many factors beyond our control, including the extent of domestic production and imports of oil and natural gas, available oil storage at Cushing, Oklahoma, and other inventory hubs, the proximity of our oil and natural gas production to pipelines and corresponding markets, the available capacity in such pipelines, the demand for oil and natural gas, the effects of weather, and the effects of state and federal regulation. While we have not experienced significant difficulty in finding a market for our production as it becomes available or in transporting our production to those markets, during 2020, we experienced some level of disruption in off-take capacity as a result of storage constraints during the initial stages of the COVID-19 pandemic. There is no assurance that we will always be able to market all of our production or obtain favorable prices.

Oil Marketing

Prices received in a regional market fluctuate frequently and can differ from NYMEX pricing due to a variety of reasons, including supply and/or demand factors, crude oil quality and location differentials. The oil differentials we received in the Gulf Coast and Rocky Mountain regions are discussed in further detail below.

With the recent exception of 2020, our crude oil prices in the Gulf Coast region have generally been positive to NYMEX and highly correlated to the changes in prices of crude oil sold under Light Louisiana Sweet. Our average NYMEX oil differential in the Gulf Coast region was a negative $1.14 per Bbl during 2020, compared to a positive $3.30 per Bbl and a positive $2.94 per Bbl during 2019 and 2018, respectively. Our current markets at various sales points along the Gulf Coast have sufficient demand to accommodate our production, but there can be no assurance of future demand.

The marketing of our Rocky Mountain region oil production is dependent on transportation through local pipelines to our primary market centers in Guernsey, Wyoming and Cushing, Oklahoma, although some of our production may ultimately be transported by third parties to Wood River, Illinois. Shipments on some of the pipelines are at or near capacity and may be subject to apportionment. We currently have access to, or have contracted for, sufficient pipeline capacity to move our oil production; however, there can be no assurance that we will be allocated sufficient pipeline capacity to move all of our oil production in the future. Because local demand for production is small in comparison to current production levels, much of the production in the Rocky Mountain region is transported to markets outside of the region. Therefore, prices in the Rocky Mountain region are further influenced by fluctuations in prices (primarily Brent and LLS) in coastal markets and by available pipeline capacity in the Midwest and Cushing markets. For the year ended December 31, 2020, the discount for our oil production relative to NYMEX in the Rocky Mountain region averaged $2.80 per Bbl, compared to $2.01 per Bbl during 2019 and $1.50 per Bbl during 2018.

COMPETITION AND MARKETS

We face competition from other oil and natural gas companies in all aspects of our business, including acquisition of producing properties, oil and gas leases, drilling rights, and CO_2 properties; marketing of oil and natural gas; and obtaining and maintaining goods, services and labor. Many of our competitors have substantially larger financial and other resources. Factors that affect our ability to acquire producing properties include available liquidity, available information about prospective properties and our expectations for earning a minimum projected return on our investments. Because of the primary nature of our core assets (our tertiary operations) and our ownership of relatively uncommon significant natural sources of CO_2 in the Gulf Coast and Rocky Mountain regions, we believe that we are effective in competing in the market and have less competition than our peers in certain aspects of our business.

The demand for qualified and experienced field personnel to drill wells and conduct field operations and for geologists, geophysicists, engineers and other professionals in the oil and gas industry can fluctuate significantly, often in correlation with commodity prices, causing periodic shortages in such personnel. Prior to the downturn in oil prices that began in late 2014, the competition for qualified technical personnel had been extensive and personnel costs escalated. There were also periods with shortages of drilling rigs and other equipment, as demand for rigs and equipment increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. We cannot be certain when we will experience these issues, and these types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results and cause significant delays in our development operations.

FEDERAL AND STATE REGULATIONS

Numerous federal, state and local laws and regulations govern the oil and gas industry. Additions or changes to these laws and regulations are often made in response to the current political or economic environment. Compliance with the evolving regulatory landscape is often difficult, and noncompliance can result in substantial penalties or the potential shutdown of operations. Additionally, the future annual cost of complying with all laws and regulations applicable to our operations is uncertain and will be ultimately determined by several factors, including future changes to legal and regulatory requirements. Management believes that continued compliance with existing laws and regulations applicable to our operations and future compliance therewith will not have a materially adverse effect on our consolidated financial position, results of operations or cash flows, although such laws and regulations, and compliance therewith, could cause significant delays or otherwise impede operations, which may, among other things, cause our expected production rates and cash flows to be less than anticipated.

The following sections describe some specific laws and regulations that may affect us. We cannot predict the cost or impact of these or other future legislative or regulatory initiatives.

Regulation of Oil and Gas Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for drilling wells; maintaining bonding requirements in order to drill or operate wells and regulating the location of wells; the method of drilling and casing wells; the surface use and restoration of properties upon which wells are drilled; the plugging and abandoning of wells; and the composition or disposal of chemicals and fluids used in connection with operations. Our operations are also subject to various environmental and conservation laws and regulations. These include regulation of the size of drilling, spacing or proration units and the density of wells that may be drilled in those units, and the unitization or pooling of oil and gas properties. In addition, federal and state environmental and conservation laws, which establish maximum rates of production from oil and gas wells, generally prohibit or restrict the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these laws and regulations may limit the amount of oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. Regulatory requirements and compliance relative to the oil and gas industry increase our costs of doing business and, consequently, affect our profitability.

Federal Energy and Climate Change Legislation and Regulation

The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, among other things, updated federal pipeline safety standards, increased penalties for violations of such standards, gave the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (the "PHMSA") authority for new damage prevention and incident notification, and directed the PHMSA to prescribe new minimum safety standards for CO_2 pipelines, which safety standards could affect our operations and the costs thereof. While the PHMSA has adopted or proposed to adopt a number of new regulations to implement this act, there has not been a substantial overhaul as to the regulation of CO_2 pipelines.

Both federal and state authorities have in recent years proposed new regulations to limit the emission of pollutants, including greenhouse gas emissions, as part of climate change initiatives and the Clean Air Act. For example, both the EPA and Bureau of Land Management ("BLM") have issued regulations for the control of methane emissions from the oil and gas industry. The EPA has promulgated regulations requiring permitting for certain sources of greenhouse gas emissions, and in May 2016, during the Obama Administration, the EPA promulgated final regulations to reduce methane and volatile organic compound emissions from the oil and gas sector. In July 2017, a federal appeals court rejected an attempt by the EPA under the Trump Administration to delay implementation of the rule. In September 2018, the EPA proposed amendments to the rule that were targeted at reducing regulatory requirements and streamlining the rule's implementation. In September 2019, the EPA also issued a notice of proposed rulemaking to remove the methane specific regulations imposed by the 2016 final rule and to remove certain other emission limitations placed on new or reconstructed transmission and storage facilities. In August 2020, the EPA released final rules that, among other things, eliminated standards for methane emissions and adjusted requirements for fugitive emissions. Those rules went into effect in the last quarter of 2020. Immediate legal challenges ensued, and while the rules were initially stayed in light of the legal challenges, the stay has been dissolved and the rules are currently in effect. The Biden Administration recently directed the EPA to consider additional regulations to establish comprehensive standards of performance and guidelines for methane and volatile organic compound emissions from existing operations in the oil and gas sector. Any resulting regulations adopted by the EPA could possibly be similar to, or even more stringent than, those promulgated by the EPA in 2016. Enforcement of such regulations may impose additional costs related to compliance with these new emission limits, as well as inspections and maintenance of several types of equipment used in our operations.

Federal, State or Indian Leases

As of December 31, 2020, approximately 25% of our net developed acreage and 12% of our fourth quarter of 2020 production related to oil and natural gas operations performed on federal acreage, including portions of CCA. Our operations on federal, state or Indian oil and gas leases, especially those in the Rocky Mountain region, are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the BLM, the Bureau of Ocean Energy Management, the Bureau of Safety and Environmental Enforcement, the Bureau of Indian Affairs, and other federal and state stakeholder agencies. The Biden Administration has, through executive action, recently suspended new leasing and other oil and natural gas approvals on federal lands. In addition, the Department of Interior recently has rescinded the ability to issue permits to drill on existing federal leases. The inability to secure new leases or permits to drill on existing leases could prevent us from expanding our oil and gas operations, in both new locations and in areas currently leased for which permits have not yet been obtained. In addition, any action by the federal government to rescind previously issued permits on the Company's existing leases could significantly disrupt our existing and future operations.

Environmental Regulations

Our oil and natural gas production, saltwater disposal operations, injection of CO_2, and the processing, handling and disposal of materials such as hydrocarbons and naturally occurring radioactive materials ("NORM") are subject to stringent regulation. We could incur significant costs, including cleanup costs resulting from a release of product, third-party claims for property damage and personal injuries, or penalties and other sanctions as a result of any violations or liabilities under environmental laws and regulations or other laws and regulations applicable to our operations. Changes in, or more stringent enforcement of, environmental laws and other laws applicable to our operations could also result in delays or additional operating costs and capital expenditures.

Various federal, state and local laws and regulations controlling the discharge of materials into the environment, or otherwise relating to the protection of the environment and human health, directly impact our oil and gas exploration, development and production operations. These include, among others, (1) regulations adopted by the EPA and various state agencies regarding approved methods of disposal for certain hazardous and nonhazardous wastes; (2) the Comprehensive Environmental Response, Compensation, and Liability Act and analogous state laws that regulate the removal or remediation of previously disposed wastes (including wastes disposed of or released by prior owners or operators), property contamination (including groundwater contamination), and remedial plugging operations to prevent future contamination; (3) the Clean Air Act and comparable state and local requirements already applicable to our operations and new restrictions on air emissions from our operations, including greenhouse gas emissions and those that could discourage the production of fossil fuels that, when used, ultimately release CO_2; (4) the Clean Water Act and comparable state and local requirements already applicable to our operations and new restrictions on wastewater discharges from our operations; (5) the Oil Pollution Act of 1990, which contains numerous requirements relating to the prevention of, and response to, oil spills into waters of the United States; (6) the Resource Conservation and Recovery Act, which is the principal federal statute governing the treatment, storage and disposal of hazardous wastes; (7) the Endangered Species Act and counterpart state legislation, which protects certain species (and their related habitats), including certain species that could be present on our leases, as threatened or endangered; and (8) state regulations and statutes governing the handling, treatment, storage and disposal of NORM and other wastes.

In the Rocky Mountain region, federal agencies' actions based upon their environmental review responsibilities under the National Environmental Policy Act can significantly impact the scope and timing of hydrocarbon development by slowing the timing of individual applications for permits to drill and requests for rights-of-way and delaying large scale planning associated with region-level resource management plans and project-level master development plans. The Biden Administration has signaled an intent to bolster agency review pursuant to the National Environmental Policy Act, including the potential of requiring climate change assessments for proposed projects.

Management believes that we are currently in substantial compliance with existing applicable environmental laws and regulations, and does not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position, results of operations or cash flows, although such laws and regulations, and compliance therewith, could cause significant delays or otherwise impede operations, which may, among other things, cause our expected production rates and cash flows to be less than anticipated.

Hydraulic Fracturing

During 2020, we fracture stimulated three wells, at Bell Creek Field, consisting primarily of small skin fractures that are utilized to remove contaminants caused by drilling muds and increase permeability near the wellbore, utilizing water-based fluids. We currently have plans to potentially hydraulically fracture up to five wells of a similar nature during 2021. We are familiar with the laws and regulations applicable to hydraulic fracturing operations and take steps to ensure compliance with these requirements.

Item 1A. Risk Factors

The risks described below fall into six broad categories related to (1) oil price volatility and demand, (2) future executive, legislative or regulatory actions, (3) financial risks, (4) risks of owning our common stock, (5) cybersecurity risks, and (6) those related to our operations and industry. These are not the only ones we face but are considered to be the most material. There may be other unknown or unpredictable economic, business, competitive, regulatory or other factors that could have material adverse effects on our future results. Past financial performance is not a reliable indicator of future performance, and historical trends should not be used to anticipate results or trends in future periods.

Risks Relating to Volatility in Oil Pricing and Demand for Oil

Low oil prices in recent years have led to significant periods of reduced cash flows and negatively affected our financial condition and results of operations.

Oil prices are the most important determinant of our operational and financial success. Oil prices are highly impacted by worldwide oil supply, demand and prices and have historically been subject to significant price changes over short periods of time. Over the last several years, NYMEX oil prices have been extremely volatile, declining from a three-year peak of $76 per Bbl in October 2018 to lows averaging $17 per Bbl in April 2020 due to the reduction in worldwide economic activity and oil demand amid the COVID-19 pandemic, plus OPEC supply pressures, before gradually increasing to the low-$60s per barrel in mid-February 2021. Based on rising COVID-19 case levels and their impact on worldwide economic activity, volatility will remain, and prices could move downward on a rapid or repeated basis, which makes planning and budgeting, acquisition transactions, capital raising, and sustaining business strategies more difficult. Our cash flow from operations is highly dependent on the prices that we receive for oil, as oil comprised approximately 97% of our 2020 production and approximately 98% of our proved reserves at December 31, 2020. The prices for oil and natural gas are subject to a variety of factors that are beyond our control. These factors include:

- the level of worldwide demand for oil and natural gas, which has been negatively affected by the economic impact of the worsening COVID-19 pandemic;
- worldwide economic conditions;
- the degree to which members of OPEC maintain oil price and production controls;
- the degree to which domestic oil and natural gas production affects worldwide supply of crude oil or its price; and
- worldwide political events, conditions and policies, including actions taken by foreign oil and natural gas producing nations.

Negative movements in oil prices could harm us in a number of ways, including:

- lower cash flows from operations may require reduced levels of capital expenditures; which in turn could lower our present and future production levels and lower the quantities and value of our oil and gas reserves, which constitute our major asset;
- we could be forced to increase our level of indebtedness, issue additional equity, or sell assets; and/or
- we could be required to impair various assets, including a write-down of our oil and natural gas assets or the value of other tangible or intangible assets.

Furthermore, some or all of our tertiary projects could become or remain uneconomical. We may also decide to suspend future expansion projects, and if prices were to drop below our operating cash break-even points for an extended period of time, we may decide to shut-in existing production, both of which could have a material adverse effect on our operations and financial condition and reduce our production.

The continued COVID-19 pandemic is likely to continue to suppress worldwide economic activity, which in turn could negatively affect our cash flow.

The spread and emergence of new variants of the COVID-19 virus continues to evolve, both in the United States and abroad. Its ultimate impact on our operational and financial performance will depend on future developments, including (1) the timing and effectiveness of administration of available vaccines domestically and around the world, which is currently thought to be the most important factor affecting the duration and intensity of the pandemic, (2) the actions to contain the virus or mitigate its impact, and (3) related restrictions on business activity and travel, all of which have had a direct impact on continued lower levels of domestic and global oil demand.

As described above, oil prices are the most important determinant of our operational and financial success. The possibility of a continued reduction in cash flows for an indeterminant period of time could impair our ability to develop our properties and grow our production and oil and gas reserve values.

A continuing financial downturn in one or more of the world's major markets could negatively affect our business and financial condition.

In addition to the current impact of the COVID-19 pandemic on the demand for oil, regional or worldwide increases in tariffs or other trade restrictions, significant international currency fluctuations, evolving political and military tensions in the Middle East and Asia, a sustained credit crisis, a severe economic contraction either regionally or worldwide or turmoil in the global financial system could materially affect our business and financial condition or impact our ability to finance operations. Negative credit market conditions could inhibit our lenders from funding our senior secured bank credit facility or cause them to restrict our borrowing base or make the terms of our senior secured bank credit facility more costly and more restrictive. Negative economic conditions could also adversely affect the collectability of our trade receivables or performance by our suppliers or cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations.

Risks Relating to Any Future Executive, Legislative or Regulatory Actions

Any future climate change initiatives by the Biden Administration, by Congress or by state regulatory or legislative bodies could negatively affect our business and operations, especially in the Rocky Mountain region.

The new Biden Administration and Congress may adopt stricter standards for, and increase oversight and regulation over, the exploration and production industry at the federal level, which measures could lead to increased costs or additional operating restrictions. Also, there is the potential for climate change legislation which could affect demand for oil on a long-term basis.

Our operations on federal, state or Indian oil and natural gas leases in the Rocky Mountain region must be conducted pursuant to permits and authorizations issued by the Bureau of Land Management, the Bureau of Ocean Energy Management, the Bureau of Safety and Environmental Enforcement, the Bureau of Indian Affairs, and other federal and state stakeholder agencies. In late January 2021, the Biden Administration, through executive action, suspended for a 60-day period new leasing and other oil and natural gas approvals on federal lands, pending review of such activity. Also, the Department of Interior recently has rescinded the ability to issue new permits to drill oil and natural gas wells on existing federal leases. Extension of these actions over a longer period could prevent us from expanding our oil and natural gas operations, in both new locations and in areas currently leased for which permits have not yet been obtained. In addition, any action by the federal government to rescind previously issued permits on the Company's existing leases, or actions to restrict our ability to access public lands or to obtain permits, including permits for additional pipeline infrastructure to transport CO_2, could significantly disrupt our existing and future operations, including our planned 105-mile CO_2 pipeline extension in the Cedar Creek Anticline area in Montana and North Dakota.

Tax proposals under discussion within the Biden Administration, if enacted, could change or remove long-time tax benefits available to the oil and gas industry for drilling and production activities.

As part of its budgetary planning, the Biden Administration has discussed a number of changes to certain provisions of federal tax law applicable to the exploration and production industry, including imposing a tax on carbon emissions, as well as eliminating long-standing deductions that benefit the fossil fuel industry. Among the specific provisions being focused upon are Internal Revenue Code ("IRC") Section 263, which allows expensing of exploration, development and intangible drilling costs, and IRC Section 613, which allows use of percentage depletion instead of cost depletion to recover drilling and development costs of oil and gas wells. Any such changes would require the U.S. Congress to pass new legislation and are likely to be part of a broader set of tax revisions. It is currently anticipated that new tax legislation will be proposed by the Administration later in 2021, the timing and specifics of which are yet to be determined, and the likelihood of passage of which is not assured.

Environmental laws and regulations applicable to our industry are costly and stringent.

Our exploration, production, and marketing operations are subject to complex and stringent federal, state, and local laws and regulations governing, among other things, the discharge of substances into the environment or otherwise relating to the protection of human health and the protection of endangered species. These laws and regulations and related public policy considerations affect the costs, manner, and feasibility of our operations and require us to make significant expenditures in order to comply. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial obligations, and the issuance of injunctions that could limit or prohibit our operations. Some of these laws and regulations may impose joint and several, strict liability for contamination resulting from spills, discharges, and releases of substances, including petroleum hydrocarbons and other wastes, without regard to fault or the legality of the original conduct. Under such laws and regulations, we could be required to remove or remediate previously disposed substances and property contamination, including wastes disposed or released by prior owners or operators.

Risks Relating to Financial Results and Condition

On September 18, 2020, we emerged from bankruptcy, which could adversely affect our business and relationships.

It is possible that our having filed for bankruptcy and our third-quarter 2020 emergence from the Chapter 11 bankruptcy proceedings could adversely affect our business and relationships with customers, employees and suppliers in the following ways:

- key suppliers could terminate their relationship or require financial assurances or enhanced performance;
- the ability to renew existing contracts and compete for new business may be adversely affected;
- the ability to attract, motivate and/or retain key executives and employees may be adversely affected;
- employees may be distracted from performance of their duties or more easily attracted to other employment opportunities; 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 financial results after emergence from bankruptcy are not comparable to our historical financial information as a result of the implementation of the plan of reorganization and our adoption of fresh start accounting.

Upon our emergence from bankruptcy, we adopted fresh start accounting. Accordingly, certain values and financial measures of the Company's consolidated financial statements subsequent to September 18, 2020 are not comparable to those in its consolidated financial statements prior to, and including September 18, 2020, although numerous operational measures are roughly comparable to those in our historical financial statements and other disclosures.

In connection with proceedings in the Bankruptcy Court, and the late third-quarter 2020 hearing to consider confirmation of the plan of reorganization, we prepared projected financial information to demonstrate to the Bankruptcy Court the feasibility of the plan of reorganization and our ability to continue operations upon our emergence from bankruptcy. Those projections were prepared at that time solely for the purpose of the bankruptcy proceedings and have not been, and will not be, updated on an ongoing basis. The projections were prepared based upon then-current prevailing economic assumptions at that time, are inherently subject to substantial and numerous uncertainties and to a wide variety of significant business, economic and competitive risks, and the assumptions underlying the projections and/or valuation estimates may prove to be wrong in material respects. Actual results will likely vary significantly from those contemplated by the projections. As a result, investors should not rely on those projections.

We may be unable to access the equity or debt capital markets to raise sufficient capital to fund our development activities or other obligations.

Recent reluctance of traditional capital sources to invest in the exploration and production sector based on market volatility, perceived underperformance and environmental, social and governance trends, has raised concerns regarding capital availability for the sector. The cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards and reduced (and in some cases ceased to provide) funding to borrowers. If those markets are unavailable, or if we are unable to access them or alternative financing sources on acceptable terms, we may be unable to carry out our business strategy, with an accompanying negative impact on our financial condition and results of operations.

Commodity derivative contracts may expose us to potential financial loss.

To reduce our exposure to fluctuations in the prices of oil and natural gas, we enter into commodity derivative contracts in order to economically hedge a portion of our forecasted oil and natural gas production. As of February 24, 2021, we have oil derivative contracts in place covering approximately 32,500 Bbls/d for 2021, 10,500 Bbls/d for the first half of 2022, and 2,000 Bbls/d for the second half of 2022. Such derivative contracts expose us to risk of financial loss, including when there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received, when the cash benefit from hedges including a sold put is limited to the extent oil prices fall below the price of any sold puts in our derivative portfolio, or when the counterparty to the derivative contract is financially constrained and defaults on its contractual obligations. In addition, these derivative contracts may limit the benefit we would otherwise receive from increases in the prices for oil and natural gas.

Risks Relating to Ownership of Denbury Securities

Sales of a substantial number of shares of our common stock in the public market, including both those issuable upon exercise of our outstanding warrants and those registrable for resale under a registration rights agreement, could cause the market price of our common stock to drop significantly, even if our business is doing well.

Approximately 40% of our currently issued and outstanding shares of common stock, currently held by five shareholders, are entitled to be registered for resale under a registration rights agreement (see Note 10, *Stockholders' Equity*, to the consolidated financial statements), for the benefit of the largest holders of our pre-emergence debt, as agreed as part of our bankruptcy plan of reorganization. Sales of a substantial number of shares of our common stock by these holders, or the perception that such sales could occur, could reduce the market price of our common stock and might also impair our ability to raise capital through future sale of our equity. Additionally, in connection with our plan of reorganization, we issued series A and series B warrants to holders of our pre-emergence debt and equity, entitling the warrant holders to exercise the warrants for up to approximately 5.5 million shares (approximately 10%) of our currently outstanding common stock on a fully diluted basis. See Note 1, *Nature of Operations and Summary of Significant Accounting Policies – Emergence from Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code*, to the consolidated financial statements regarding the specific terms of the warrants. The future exercise of a large number of warrants, followed by the subsequent sale of the acquired stock into the market, could also negatively affect our common stock price. We cannot predict the likelihood of sales of shares by these two groups of holders of our common stock or their amounts, or the effect of any such sales on the prevailing market price of our common stock.

The trading market for our common stock and its market price may be affected by our limited trading volume.

Upon our emergence from bankruptcy, our old common stock was canceled and we issued new common stock. The market price and trading volume of our common stock is affected by numerous factors, many of which are beyond our control. These factors include, among other things, the overhang of shares of our common stock registered for resale under a registration statement as discussed above, the concentration of holdings of our common stock, and on a longer-term basis, the potential future dilution of up to 5.5 million shares of our common stock acquirable upon exercise of our series A or series B warrants, which dilution from exercise of the series A or series B warrants could be reduced to the extent warrants are exercised on a cashless basis. No assurance can be given as to the liquidity of the trading market for the common stock.

Risks Relating to a Cybersecurity Breach

A cyber breach could occur and result in information theft, data corruption, operational disruption, and/or financial loss.

Our business has become increasingly dependent on digital technologies to conduct day-to-day operations, including certain of our exploration, development and production activities. We depend on digital technology, among other things, to process and record financial and operating data; analyze seismic and drilling information; monitor and control pipeline and plant equipment; and process and store personally identifiable information of our employees, industry partners and royalty owners. Cyberattacks on businesses have escalated in recent years, exemplified by the recent delayed discovery of the Russian-sponsored hack of U.S. governmental agencies and hundreds of U.S. corporations which did not affect our systems. Our technologies, systems and networks, or those of software providers that we use, may become the target of cyberattacks or information security breaches that could compromise our process control networks or other critical systems and infrastructure, resulting in disruptions to our business operations, harm to the environment or our assets, disruptions in access to our financial reporting systems, or loss, misuse or corruption of our critical data and proprietary information, including our business information and that of our employees, partners and other third parties. Successful attacks which disable third-party pipelines or processing facilities upon which we depend could materially adversely affect our operations. Any of the foregoing may be exacerbated by a delay or failure to detect a cyber incident. Although we have not incurred any material losses from cyberattacks, future cyberattacks could result in significant financial losses, legal or regulatory violations, reputational harm, and legal liability.

Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing successful attacks from the increasing number of sophisticated intrusions based on technological advances. We may be required to expend significant additional resources to continue to modify or enhance our procedures and controls or to upgrade our digital and operational systems, related infrastructure, technologies and network security, which could increase our costs. The Audit Committee’s duties and responsibilities include reviewing and discussing the Company’s guidelines and policies with respect to risk assessment and risk management, as well as the Company’s major financial and cybersecurity risk exposures and the steps that management has taken to monitor and control such exposures.

Risks Relating to Our Operations and Industry

Our future performance depends upon our ability to effectively develop our existing oil and natural gas reserves and find or acquire additional oil and natural gas reserves that are economically recoverable.

Unless we can successfully develop our existing reserves and/or replace the reserves that we produce, our reserves will decline, resulting eventually in a decrease in oil and natural gas production and lower revenues and cash flows from operations. We have historically replaced reserves through both acquisitions and internal organic growth activities. For internal organic growth activities, the magnitude of proved reserves that we can book in any given year depends on our progress with new floods and the timing of the production response, as well as the success of exploitation projects. In the future, we may not be able to continue to replace reserves at acceptable costs. The business of exploring for, developing or acquiring reserves is capital intensive. We may not be able to make the necessary capital investment to maintain or expand our oil and natural gas reserves if our cash flows from operations are reduced, whether due to current oil or natural gas prices or otherwise, or if external sources of capital become limited or unavailable. Further, the process of using CO_2 for tertiary recovery, and the related infrastructure, requires significant capital investment prior to any resulting and associated production and cash flows from these projects, heightening potential capital constraints. If our capital expenditures are restricted, or if outside capital resources become limited, we will not be able to maintain our current production levels.

Estimating our reserves, production and future net cash flows is difficult to do with any certainty.

Estimating quantities of proved oil and natural gas reserves requires interpretations of available technical data and various assumptions, including future production rates, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, and the assumed effect of governmental rules and regulations. There are numerous uncertainties about when a property may have proved reserves as compared to potential or probable reserves, particularly relating to our tertiary recovery operations. Forecasting the amount of oil reserves recoverable from tertiary operations, and the production rates anticipated therefrom, requires estimates, one of the most significant being the oil recovery factor.

Actual results most likely will vary from our estimates. Also, the use of a 10% discount factor for reporting purposes, as prescribed by the SEC, may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business, and the oil and natural gas industry in general, are subject. Any significant inaccuracies in these interpretations or assumptions, or changes of conditions, could result in a revision of the quantities and net present value of our reserves.

The reserves data included in documents incorporated by reference represents estimates only. Quantities of proved reserves are estimated based on economic conditions, including first-day-of-the-month average oil and natural gas prices for the 12-month period preceding the date of the assessment. The representative oil and natural gas prices used in estimating our December 31, 2020 reserves, after adjustments for market differentials and transportation expenses by field, were $35.84 per Bbl for crude oil and $1.70 per Mcf for natural gas. Our reserves and future cash flows may be subject to revisions based upon changes in economic conditions, including oil and natural gas prices, as well as due to production results, results of future development, operating and development costs, and other factors. Downward revisions of our reserves could have an adverse effect on our financial condition and operating results. Actual future prices and costs may be materially higher or lower than the prices and costs used in our estimates.

Our production will decline if our access to sufficient amounts of carbon dioxide is limited.

Our long-term strategy is primarily focused on our CO_2 tertiary recovery operations. The crude oil production from our tertiary recovery projects depends, in large part, on having access to sufficient amounts of naturally occurring and industrial-sourced CO_2. Our ability to produce oil from these projects would be hindered if our supply of CO_2 was limited due to, among other things, problems with our current CO_2 producing wells and facilities, including compression equipment, catastrophic pipeline failure or our ability to economically purchase CO_2 from industrial sources. This could have a material adverse effect on our financial condition, results of operations and cash flows. Our anticipated future crude oil production from tertiary operations is also dependent on the timing, volumes and location of CO_2 injections and, in particular, on our ability to increase our combined purchased and produced volumes of CO_2 and inject adequate amounts of CO_2 into the proper formation and area within each of our tertiary oil fields.

The development of our naturally occurring CO_2 sources involves the drilling of wells to increase and extend the CO_2 reserves available for use in our tertiary fields. These drilling activities are subject to many of the same drilling and geological risks of drilling and producing oil and gas wells (see *Oil and natural gas development and producing operations involve various risks* below). Furthermore, recent market conditions may cause the delay or cancellation of construction of plants that produce industrial-sourced CO_2 as a byproduct that we can purchase, thus limiting the amount of industrial-sourced CO_2 available for our use in our tertiary operations.

Certain of our operations may be limited during certain periods due to severe weather conditions and other regulations.

Our operations in the Gulf Coast region may be subjected to adverse weather conditions such as hurricanes, flooding and tropical storms in and around the Gulf of Mexico, as well as freezing temperatures, ice and snow, that can damage oil and natural gas facilities and delivery systems and disrupt operations, which can also increase costs and have a negative effect on our results of operations. Certain of our operations in North Dakota, Montana and Wyoming, including the construction of CO_2 pipelines, the drilling of new wells and production from existing wells, are conducted in areas subject to extreme weather conditions including severe cold, snow and rain, which conditions may cause such operations to be hindered or delayed or otherwise require that they be conducted only during non-winter months, and depending on the severity of the weather, could have a negative effect on our results of operations in these areas. Further, the potential impacts of climate change on our operations may include unusually intense rainfall and storm patterns, rising sea levels and increased high temperatures, the last of which imposes certain physical constraints on our CO_2 injections in our operations in the Gulf Coast.

Certain of our operations in the Rocky Mountain region are confined to certain time periods due to environmental regulations, federal restrictions on when drilling can take place on federal lands, and lease stipulations designed to protect certain wildlife, which regulations, restrictions and limitations could slow down our operations, cause delays, increase costs and have a negative effect on our results of operations. In addition, a number of governmental bodies have introduced or are contemplating regulatory changes in response to various proposals to combat climate change and how it should be dealt with. Legislation and increased regulation regarding climate change could impose significant costs on us and possibly affect our financial condition and operating performance.

Oil and natural gas development and producing operations involve various risks.

Our operations are subject to all of the risks normally incident and inherent to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including, without limitation, pipe failure; fires; formations with abnormal pressures; uncontrollable flows of oil, natural gas, brine or well fluids; release of contaminants into the environment and other environmental hazards and risks; and well blowouts, cratering or explosions. In addition, our operations are sometimes near populated commercial or residential areas, which adds additional risks. The nature of these risks is such that some liabilities could exceed our insurance policy limits or otherwise be excluded from, or limited by, our insurance coverage, as in the case of environmental fines and penalties, for example, which are excluded from coverage as they cannot be insured.

We could incur significant costs related to these risks that could have a material adverse effect on our results of operations, financial condition and cash flows or could have an adverse effect upon the profitability of our operations. Additionally, a portion of our production activities involves CO_2 injections into fields with wells plugged and abandoned by prior operators. It is often difficult (or impracticable) to determine whether a well has been properly plugged prior to commencing injections and pressuring the oil reservoirs. We may incur significant costs in connection with remedial plugging operations to prevent environmental contamination and to otherwise comply with federal, state and local regulations relative to the plugging and abandoning of our oil, natural gas and CO_2 wells. In addition to the increased costs, if wells have not been properly plugged, modification to those wells may delay our operations and reduce our production.

Development activities are subject to many risks, including the risk that we will not recover all or any portion of our investment in such wells. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, including hurricanes and tropical storms in and around the Gulf of Mexico, as well as freezing temperatures, ice and snow, that can damage oil and natural gas facilities and delivery systems and disrupt operations, and winter conditions and forest fires in the Rocky Mountain region that can delay or impede operations;
- compliance with environmental and other governmental requirements;
- the cost of, or shortages or delays in the availability of, drilling rigs, equipment, pipelines and services; and
- title problems.

Our planned tertiary operations and the related construction of necessary CO_2 pipelines could be delayed by difficulties in obtaining pipeline rights-of-way and/or permits and/or by the listing of certain species as threatened or en**dangered.**

The production of crude oil from our planned tertiary operations is dependent upon having access to pipelines to transport available CO_2 to our oil fields at a cost that is economically viable. Our future construction of CO_2 pipelines will require us to obtain rights-of-way from private landowners, state and local governments and the federal government in certain areas. Certain states where we operate have considered or may again consider the adoption of laws or regulations that could limit or eliminate the ability of a pipeline owner or of a state, state's legislature or its administrative agencies to exercise eminent domain over private property, in addition to possible judicially imposed constraints on, and additional requirements for, the exercise of eminent domain. We also often conduct Rocky Mountain operations on federal and other oil and natural gas leases inhabited by species that could be listed as threatened or endangered under the Endangered Species Act, which listing could lead to tighter restrictions as to federal land use and other land use where federal approvals are required. These laws and regulations, together with any other changes in law related to the use of eminent domain or the listing of certain species as threatened or endangered, could inhibit or eliminate our ability to secure rights-of-way or otherwise access land for current or future pipeline construction projects and may require additional regulatory and environmental compliance, and increased costs in connection therewith, which could delay our CO_2 pipeline construction schedule and initiation of our pipeline operations, and/or increase the costs of constructing our pipelines.

The marketability of our production is dependent upon transportation lines and other facilities, most of which we do not control. When these facilities are unavailable, our operations can be interrupted and our revenues reduced.

The marketability of our oil and natural gas production depends, in part, upon the availability, proximity and capacity of transportation lines owned by third parties. In general, we do not control these transportation facilities, and our access to them may be limited or denied. A significant disruption in the availability of, and access to, these transportation lines or other production facilities could adversely impact our ability to deliver to market or produce our oil and thereby cause a significant interruption in our operations.

We may lose key executive officers or specialized technical employees, which could endanger the future success of our operations.

Our success depends to a significant degree upon the continued contributions of our executive officers, other key management and specialized technical personnel. Our employees, including our executive officers, are employed at will and do not have employment agreements. We believe that our future success depends, in large part, upon our ability to hire and retain highly skilled personnel.

The loss of one or more of our large oil and natural gas purchasers could have an adverse effect on our operations.

For the year ended December 31, 2020, three purchasers individually accounted for 10% or more of our oil and natural gas revenues and, in the aggregate, for 54% of such revenues. The loss of a large single purchaser could adversely impact the prices we receive or the transportation costs we incur.

Item 1B. Unresolved Staff Comments

There are no unresolved written SEC staff comments regarding our periodic or current reports under the Securities Exchange Act of 1934 received 180 days or more before the end of the fiscal year to which this annual report on Form 10-K relates.

Item 2. Properties

Information regarding the Company's properties called for by this item is included in Item 1*, Business and Properties – Oil and Natural Gas Operations*. We also have various operating leases for rental of office space, office and field equipment, and land easements. See Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Commitments, Obligations and Off-Balance Sheet Arrangements*, and Note 5, *Leases*, to the consolidated financial statements for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our business or finances, litigation is subject to inherent uncertainties. We accrue for losses from litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

Chapter 11 Proceedings

On July 30, 2020, Denbury Resources Inc. and each of its wholly-owned subsidiaries filed for relief under chapter 11 of the Bankruptcy Code. The chapter 11 cases were administered jointly under the caption "*In re Denbury Resources Inc., et al.*, Case No. 20-33801". On September 2, 2020, the Bankruptcy Court entered the Confirmation Order and on the Emergence Date, all of the conditions of the Plan were satisfied or waived and the Plan became effective and was implemented in accordance with its terms. On September 30, 2020, the Bankruptcy Court closed the chapter 11 cases of each of Denbury Inc.'s wholly-owned subsidiaries. The chapter 11 case captioned "*In re Denbury Resources Inc., et al.*, Case No. 20-33801" will remain pending until the final resolution of all outstanding claims.

Riley Ridge Helium Supply Contract Claim

As part of our 2010 and 2011 acquisitions of the Riley Ridge Unit and associated gas processing facility that was under construction, the Company assumed a 20-year helium supply contract under which we agreed to supply the helium separated from the full well stream by operation of the gas processing facility to a third-party purchaser, APMTG Helium, LLC ("APMTG").

As the gas processing facility was shut-in during mid-2014 due to significant technical issues, we were not able to supply helium under the helium supply contract. In a case filed in November 2014 in the Ninth Judicial District Court of Sublette County, Wyoming, APMTG claimed multiple years of liquidated damages for non-delivery of volumes of helium specified under the helium supply contract. The Company claimed that its contractual obligations were excused by virtue of events that fall within the force majeure provisions in the helium supply contract.

On March 11, 2019, the trial court entered a final judgment that a force majeure condition did exist, but such condition only excused the Company's performance for a 35-day period in 2014, and as a result the Company should pay APMTG liquidated damages and interest thereon for all other time periods for performance from contract commencement to the close of evidence (November 29, 2017). On December 4, 2020, the Wyoming Supreme Court entered a judgment affirming the trial court's ruling on all counts and, as a result, the Company paid total liquidated damages (including interest) of $52.1 million to APMTG on December 23, 2020 in full satisfaction of all claims. The Company had previously recorded an accrual for these costs in "Accounts payable and accrued liabilities" in our Consolidated Balance Sheets.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Market Information and Holders of Record

On September 18, 2020, upon emergence from bankruptcy, all existing shares of Predecessor common stock were cancelled and new shares of common stock in the Successor were issued to former holders of debt cancelled in bankruptcy. On September 21, 2020 the Successor's common stock commenced trading on the New York Stock Exchange ("NYSE") under the symbol "DEN." As of January 31, 2021, based on information from the Company's transfer agent, Broadridge Stock Transfer Agent, there was one holder of record of Denbury's common stock.

The Predecessor's common stock was listed on the NYSE under the symbol "DNR", but the NYSE indefinitely suspended trading of the Predecessor stock on July 31, 2020 as a result of Denbury Resources Inc. and its subsidiaries filing voluntary positions for reorganization under chapter 11 of the Bankruptcy Code. From July 31, 2020 until September 21, 2020, during the Company's Chapter 11 reorganization, trading of the Predecessor common stock occurred on the OTC Pink Open Market.

Dividends

We have not paid dividends on our Successor common stock and have no current plans to declare common stock dividends. Our credit agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto requires us to meet certain financial covenants at the time dividend payments are made. For further discussion, see Note 8, *Long-Term Debt*, to the consolidated financial statements.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

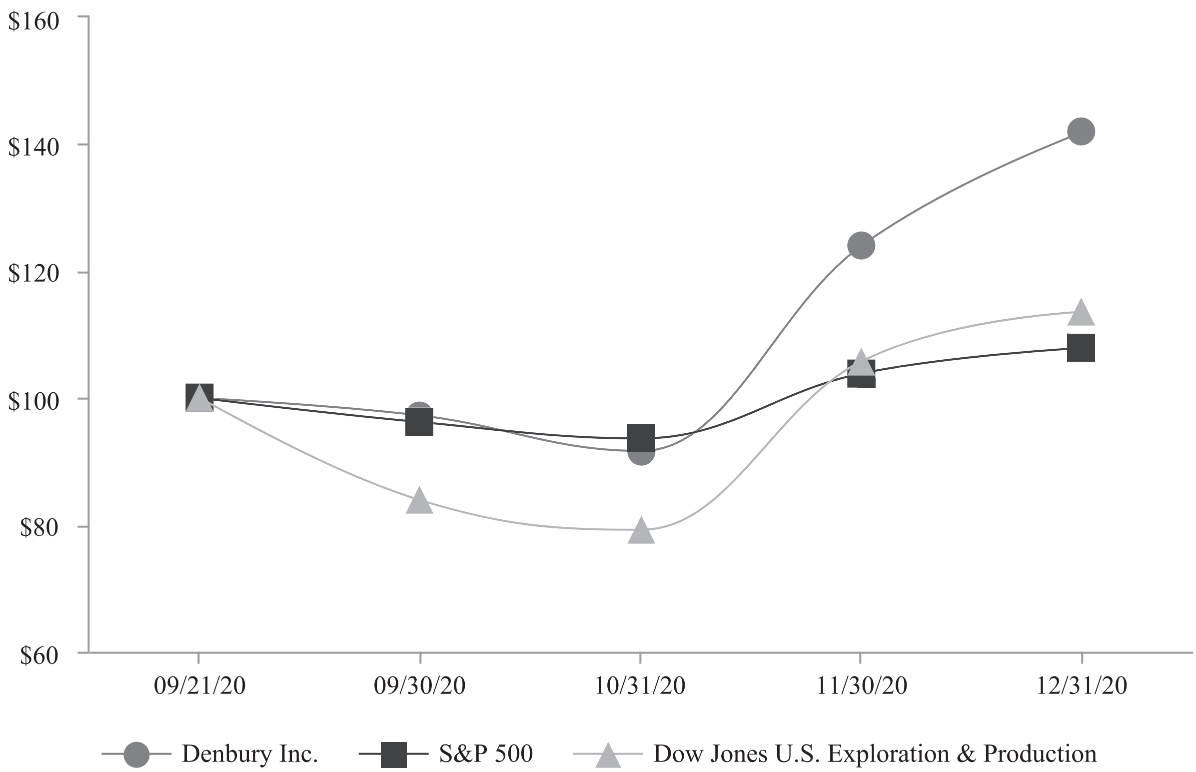
We did not repurchase any shares of our Successor common stock during the fourth quarter of 2020.

Stock Performance Graphs

The following Performance Graphs and related information shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission ("SEC"), nor shall such information be incorporated by reference into any future filings under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filings.

The following graph illustrates changes over the period September 21, 2020 through December 31, 2020, in cumulative total stockholder return on the Successor common stock as measured against the cumulative total return of the S&P 500 Index and the Dow Jones U.S. Exploration and Production Index. The graph tracks the performance of a $100 investment in our common stock and in each index (with the reinvestment of all dividends for the index securities) from September 21, 2020 to December 31, 2020.

SEPTEMBER 21, 2020 to DECEMBER 31, 2020
COMPARISON OF CUMULATIVE TOTAL RETURN – POST BANKRUPTCY EMERGENCE

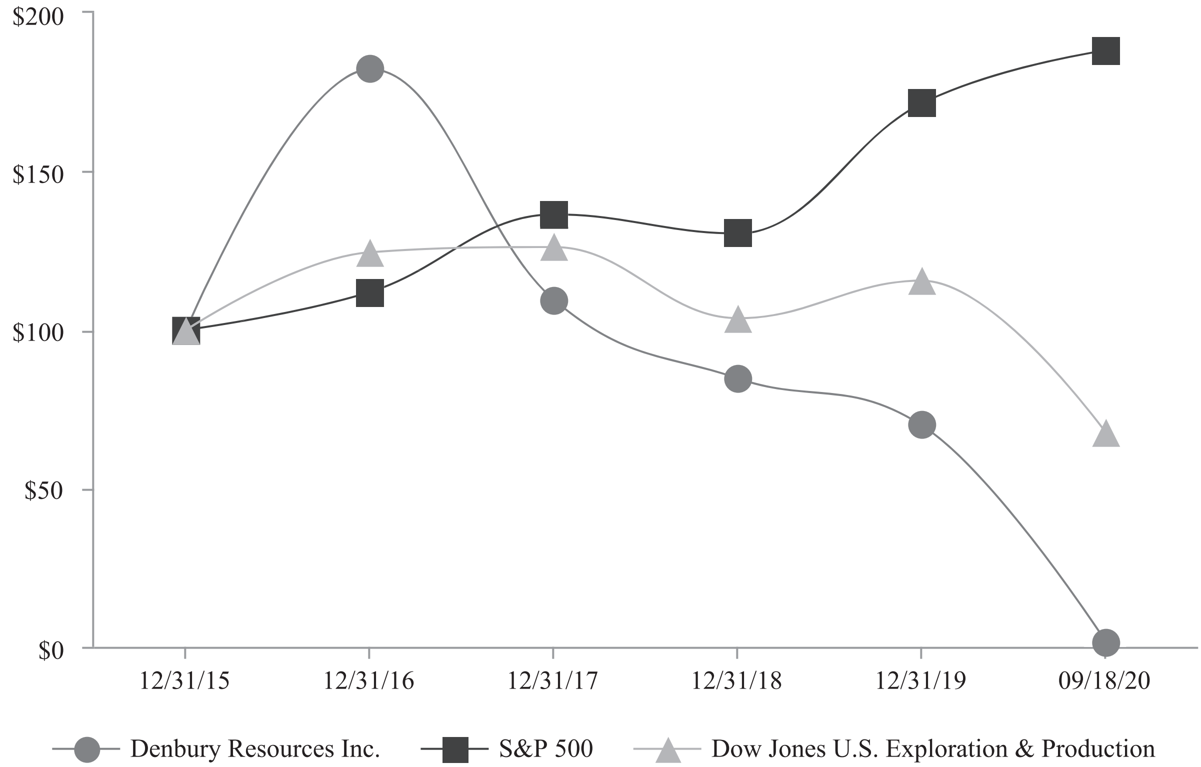


	9/21/20	9/30/20	10/31/20	11/30/20	12/31/20
Denbury Inc.	$ 100	$ 97	$ 92	$ 124	$ 142
S&P 500	100	96	94	104	108
Dow Jones U.S. Exploration & Production	100	84	79	106	114

Denbury Inc.

The following graph illustrates changes over the period December 31, 2015 through September 18, 2020, in cumulative total stockholder return on the Predecessor common stock as measured against the cumulative total return of the S&P 500 Index and the Dow Jones U.S. Exploration and Production Index. The graph tracks the performance of a $100 investment in our common stock and in each index (with the reinvestment of all dividends for the index securities) from December 31, 2015 to September 18, 2020.

DECEMBER 31, 2015 to SEPTEMBER 18, 2020
COMPARISON OF CUMULATIVE TOTAL RETURN – PRE-BANKRUPTCY EMERGENCE



	12/31/15	12/31/16	12/31/17	12/31/18	12/31/19	9/18/20
Denbury Resources Inc.	$ 100	$ 182	$ 109	$ 85	$ 70	$ 1
S&P 500	100	112	136	130	171	188
Dow Jones U.S. Exploration & Production	100	124	126	104	116	67

Item 6. Selected Financial Data

Not included based upon the Company voluntarily early adopting the SEC's amendments to Item 301 of Regulation S-K which became effective on February 10, 2021.

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and Notes thereto included in Item 8, *Financial Statements and Supplementary Information*. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with *Risk Factors* under Item 1A of this Form 10-K, along with *Forward-Looking Information* at the end of this section for information on the risks and uncertainties that could cause our actual results to be materially different from our forward-looking statements. For a discussion of the financial results for the fiscal year ended December 31, 2018, see Part II, Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*, of our Annual Report on Form 10-K for the fiscal year ended December 31, 2019, as filed with the SEC on February 27, 2020.

OVERVIEW

Denbury is an independent energy company with operations focused on producing oil from mature oil fields in the Gulf Coast and Rocky Mountain regions. The Company is differentiated by its focus on CO_2 EOR and the emerging CCUS industry, supported by the Company's CO_2 EOR technical and operational expertise and its extensive CO_2 pipeline infrastructure. The utilization of captured industrial-sourced CO_2 in EOR significantly reduces the carbon footprint of the oil that Denbury produces, underpinning the Company's goal to fully offset its Scope 1, 2, and 3 CO_2 emissions within the decade.

Emergence from Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code. On July 30, 2020 (the "Petition Date"), Denbury Resources Inc. and its subsidiaries filed petitions for reorganization in a "prepackaged" voluntary bankruptcy (the "Chapter 11 Restructuring") under chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court") under the caption "*In re Denbury Resources Inc., et al.*, Case No. 20-33801". On September 2, 2020, the Bankruptcy Court entered an order (the "Confirmation Order") confirming the chapter 11 plan of reorganization (the "Plan") and approving the Disclosure Statement, and on September 18, 2020 (the "Emergence Date"), the Plan became effective in accordance with its terms and the Company emerged from Chapter 11. Key accomplishments of the Chapter 11 Restructuring included the following:

- Eliminated approximately $2.1 billion of bond debt by issuing equity and/or warrants to the holders of that debt;
- Significantly improved leverage ratios;
- Reduced ongoing annual interest expense by approximately $165 million, significantly lowering our cash flow breakeven level;
- Eliminated approximately $9 million from ongoing general and administrative expenses by terminating certain office leases and relocating our corporate headquarters; and
- Established a new $575 million senior secured bank credit facility with $482.0 million of availability at December 31, 2020 after outstanding letters of credit.

For more information on the Chapter 11 Restructuring and related matters, refer to Note 1, *Nature of Operations and Summary of Significant Accounting Policies – Emergence from Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code*, and Note 8, *Long-Term Debt*, to the consolidated financial statements.

Fresh Start Accounting. Upon emergence from bankruptcy, we met the criteria and were required to adopt fresh start accounting in accordance with Financial Accounting Standards Board Codification ("FASC") Topic 852, *Reorganizations*, which on the Emergence Date resulted in a new entity, the Successor, for financial reporting purposes, with no beginning retained earnings or deficit as of the fresh start reporting date. References to "Successor" relate to the financial position and results of operations of the Company subsequent to the Company's emergence from bankruptcy on September 18, 2020, and references to "Predecessor" relate to the financial position and results of operations of the Company prior to, and including, September 18, 2020. In order to assist investors in understanding the comparability of our financial results for the applicable periods, we have provided certain comparative analysis on a combined basis, which management believes provides meaningful information to assist investors in understanding our financial results for the applicable period, but should not be considered in isolation, as a substitute for, or more meaningful than, independent results of the Predecessor and Successor periods for the year reported in accordance with GAAP.

Fresh start accounting requires that new fair values be established for the Company's assets, liabilities and equity as of the date of emergence from bankruptcy, September 18, 2020, and therefore certain values and operational results of the consolidated financial statements subsequent to September 18, 2020 are not comparable to the Company's consolidated financial statements prior to, and including September 18, 2020, principally due to the Emergence Date re-evaluation of the fair value of our oil and natural gas properties, CO_2 properties, and pipelines, together with the conversion of over $2 billion of previously outstanding debt into new common stock and/or warrants in the Successor. The reorganization value derived from the range of enterprise values associated with the Plan was allocated to the Company's identifiable tangible and intangible assets and liabilities based on their fair values. The Emergence Date fair values of the Successor's assets and liabilities differ materially from their recorded values as reflected on the historical balance sheet of the Predecessor and may materially affect our results of operations in Successor reporting periods.

Oil Price Impact on Our Business. Our financial results are significantly impacted by changes in oil prices, as 97% of our production is oil. Changes in oil prices impact all aspects of our business, most notably our cash flows from operations, revenues, capital allocation and budgeting decisions, and oil and natural gas reserves volumes. The table below outlines changes in our realized oil prices, before and after commodity hedging impacts, over the last three years:

	Year Ended December 31,		
	2020	2019	2018
Average net realized prices			
Oil price per Bbl - excluding impact of derivative settlements	$ 37.78	$ 58.26	$ 66.11
Oil price per Bbl - including impact of derivative settlements	43.40	59.40	57.91

Response to 2020 Oil Price Declines. In January and February 2020, NYMEX WTI oil prices averaged in the mid-$50s per Bbl range before a precipitous decline in oil prices that began in early March 2020 due to the combination of the COVID-19 coronavirus ("COVID-19") pandemic and the failure of the group of oil producing nations known as OPEC+ to reach an agreement over proposed oil production cuts. While oil prices have improved from the low points experienced during the second quarter of 2020, the concerns and uncertainties around the balance of supply and demand for oil are expected to continue for some time.

The precipitous decline in oil prices that began in the latter part of the first quarter of 2020 caused us to reassess our original plans for 2020, and as a result the Company adopted the following operational and financial measures:

- Reduced budgeted 2020 capital spending by $80 million, or 44%, to a range of $95 million to $105 million;
- Deferred the CO_2 pipeline to Cedar Creek Anticline and the Cedar Creek Anticline CO_2 tertiary flood development project beyond 2020;
- Implemented cost reduction measures including shutting-in production, shutting down compressors, negotiating reductions with vendors, delaying uneconomic well repairs and workovers and reducing our workforce;
- Restructured approximately 50% of our three-way collars covering 14,500 Bbls/d into fixed-price swaps for the second quarter through the fourth quarter of 2020 in order to increase downside oil price protection; and
- Evaluated production economics at each field and shut-in production beginning in late March 2020 that was uneconomic to produce or repair based on then-prevailing oil prices.

Comparative Financial Results and Highlights. As a result of Denbury filing for bankruptcy and emerging from bankruptcy during September 2020, our financial results are broken out between the Predecessor period (January 1, 2020 through September 18, 2020) and the Successor period (September 19, 2020 through December 31, 2020). For the Predecessor period, we recognized a net loss of $1.4 billion, and for the Successor period, we recognized a net loss of $50.7 million. The primary drivers of our significant financial net loss for the Predecessor period included the following:

- A $996.7 million full cost pool ceiling test write-down during the Predecessor period as a result of the decline in NYMEX oil prices (see *Depletion, Depreciation, and Amortization ("DD&A") – Full Cost Pool Ceiling Test* below); and
- Reorganization items, net, resulted in an $850.0 million charge during the Predecessor period, due to fresh start accounting adjustments of $1.9 billion to decrease the carrying value of our assets, partially offset by a gain on

settlements of liabilities subject to compromise of $1.0 billion, primarily representing the net impact of approximately $2.1 billion of debt elimination offset by the new equity value in Denbury.

On a comparative basis, we recognized net income of $217.0 million, or $0.45 per diluted share, during 2019. The following reflects some of the primary drivers for our change in operating results between full-year 2020 and 2019:

- Oil and natural gas revenues decreased by $518.8 million (43%), with 31% of the decrease due to lower commodity prices and 12% due to lower production;
- Lease operating expenses decreased by $125.7 million (26%), primarily due to cost reduction measures in light of the low oil price environment, as well as the sale of a portion of our working interest in four southeast Texas oil fields (see *March 2020 Sale of Working Interests in Certain Texas Fields* below) and Delhi insurance reimbursements (see *Delhi Insurance Recovery* below);
- Commodity derivative expense decreased by $110.2 million ($40.1 million of income during 2020 compared to $70.1 million of expense during 2019), resulting from a $78.9 million increase in cash receipts upon settlement and an incremental $31.3 million decrease in noncash fair value losses between periods;
- A noncash gain on debt extinguishment of $156.0 million during 2019 compared to $19.0 million during 2020; and
- Reductions across numerous expense categories including $33.6 million in taxes other than income and $15.0 million in general and administrative expenses.

March 2021 Acquisition of Wyoming CO_2 EOR Fields. In December 2020, we entered into an agreement to acquire a nearly 100% working interest (approximately 83% net revenue interest) in the Big Sand Draw and Beaver Creek oil fields located in Wyoming for $12 million cash, including surface facilities and a 46-mile CO_2 transportation pipeline to the acquired fields. The agreement provides for us to make two contingent cash payments of $4 million each in 2021 and 2022 if NYMEX WTI oil prices average at least $50 per Bbl during the respective calendar years. The acquisition closed on March 3, 2021.

October 2020 Restructuring of CO_2 Pipeline Agreements. In late October 2020, we restructured our CO_2 pipeline financing arrangements with Genesis Energy, L.P. ("Genesis"), whereby (1) Denbury reacquired the NEJD pipeline system from Genesis in exchange for $70 million to be paid in four equal payments during 2021, representing full settlement of all remaining obligations under the NEJD secured financing lease; and (2) Denbury reacquired the Free State Pipeline from Genesis in exchange for a one-time payment of $22.5 million on October 30, 2020.

Delhi Insurance Recovery. During 2020, we received insurance reimbursements totaling $16.1 million ($15.4 million net to Denbury's interest) for previously-incurred well control costs, cleanup costs, and damages associated with a 2013 incident at Delhi Field. Denbury's portion of the insurance recovery of $15.4 million was recorded as a reduction to lease operating expenses.

Houston Area Land Sales. As part of our marketing non-producing surface acreage primarily around the Houston area for sale, we completed the sale of a portion of this acreage for gross proceeds of approximately $29 million during 2020. To date, we have closed acreage sales for total gross proceeds of approximately $49 million, and we currently have an additional $4 million under contract which is expected to close in the third quarter of 2021.

March 2020 Sale of Working Interests in Certain Texas Fields. On March 4, 2020, we sold half of our nearly 100% working interest positions in four southeast Texas oil fields (consisting of Webster, Thompson, Manvel and East Hastings) for $40 million net cash and a carried interest in ten wells to be drilled by the purchaser (the "Gulf Coast Working Interests Sale").

CAPITAL RESOURCES AND LIQUIDITY

Overview. Our primary sources of capital and liquidity are our cash flows from operations and availability of borrowing capacity under our Successor bank credit facility. Our most significant cash outlays relate to our development capital expenditures and current period operating expenses. The most significant changes during 2020 to our capital resources and liquidity resulted from our financial restructuring and emergence from Chapter 11 reorganization in which we eliminated approximately $2.1 billion of bond debt and reduced ongoing annual interest expense by approximately $165 million, significantly improving our cash flow on a go-forward basis.

2020 Cash Sources and Uses. NYMEX oil prices decreased significantly during 2020, directly reducing our operating cash flow; however, we took significant actions to reduce capital expenditures and operating expenses in order to adjust our spending levels such that our spending for ongoing operations was below our cash flow generated from operations. During 2020, we generated cash flows from operations of $153.7 million, while incurring capital expenditures of $95.2 million and capitalized interest of $24.1 million, resulting in approximately $50 million of cash flow in excess of capital expenditures (excluding working capital changes, but including $46.4 million of interest payments treated as repayment of debt in our financial statements). During 2020, we further supplemented our cash flow and liquidity with proceeds from asset sales, including $40 million of proceeds from our March 2020 sale of working interests in four southeast Texas fields and by $29 million of proceeds from sales of non-producing surface acreage primarily around the Houston area. These supplemental cash inflows were offset with a similar amount of debt reduction and repurchase of the NEJD and Free State CO_2 pipelines from Genesis.

Capital Expenditure Summary. The following table reflects incurred capital expenditures (including accrued capital) for the years ended December 31, 2020, 2019 and 2018:

In thousands	Year Ended December 31, 2020	2019	2018
Capital expenditures by project			
Tertiary oil fields	$ 26,402	$ 93,331	$ 142,560
Non-tertiary fields	25,666	71,014	104,811
Capitalized internal costs[1]	32,956	46,031	46,599
Oil and natural gas capital expenditures	85,024	210,376	293,970
CO_2 pipelines, sources and other	10,144	26,545	28,700
Capital expenditures, before acquisitions and capitalized interest	95,168	236,921	322,670
Acquisitions of oil and natural gas properties	176	284	541
Capital expenditures, before capitalized interest	95,344	237,205	323,211
Capitalized interest	24,146	36,671	37,079
Capital expenditures, total	$ 119,490	$ 273,876	$ 360,290

(1) Includes capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

2021 Plans and Capital Budget. Oil prices continued to strengthen during the first two months of 2021, reaching the low-$60s per barrel in mid-February. Considering the current oil price environment and strategic importance of the CO_2 flood at Cedar Creek Anticline ("CCA"), we plan to move forward in 2021 with the development of this significant long-term project. We expect to allocate approximately $150 million of capital in 2021 to this CCA development, consisting of approximately $100 million dedicated to the 105-mile extension of the Greencore CO_2 pipeline from Bell Creek to CCA, with the remainder dedicated to facilities, well work and field development at CCA. In total, we estimate that our total development capital expenditures in 2021, excluding acquisitions and capitalized interest, will be in a range of $250 million to $270 million. Based on current oil prices and the Company's hedge positions, we estimate that our 2021 cash flows from operations will exceed our budgeted level of planned development capital expenditures. In addition to our 2021 planned development capital, we acquired the Big Sand Draw and Beaver Creek oil fields in Wyoming in early March 2021 for a cash purchase price of $12 million before closing adjustments. Also, we plan to settle the remaining debt obligation to Genesis for the NEJD CO_2 pipeline, with $70 million in payments to be made over the course of 2021. We expect to fulfill these remaining obligations from cash flow and borrowings under our bank credit facility. At December 31, 2020, we had $482 million of availability under our bank credit facility, which we believe is more than adequate to cover any near-term liquidity needs. To supplement our liquidity, we may seek other sources of funding for all or a portion of the CCA CO_2 Pipeline expenditure.

The 2021 capital budget, excluding capitalized interest and acquisitions, provides for approximate spending of $260 million at the midpoint of our guidance as follows:

- $100 million for the 105-mile extension of the Greencore CO_2 pipeline to CCA
- $50 million for CCA tertiary well work, facilities, and field development;

- $50 million allocated for other tertiary oil field development;
- $35 million allocated for non-tertiary oil field development; and
- $25 million for other capital items such as capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

Based on our capital spending plans, we currently anticipate 2021 average daily production to be between 47,500 BOE/d and 51,500 BOE/d, including the Big Sand Draw and Beaver Creek working interests acquisition expected to close in early March 2021. Our anticipated 2021 production level compares to 2020 average continuing production of 50,957 BOE/d, after reduction for 2020 property divestitures.

New Senior Secured Bank Credit Agreement. In connection with our emergence from Chapter 11 proceedings on September 18, 2020, we entered into a bank credit agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (the "Bank Credit Agreement"). The Bank Credit Agreement is a senior secured revolving credit facility with an initial borrowing base and lender commitments of $575 million, under which we had $70.0 million borrowed as of December 31, 2020, leaving us with $482.0 million of availability after consideration of $23.0 million of outstanding letters of credit. Availability under the Bank Credit Agreement is subject to a borrowing base, which is redetermined semiannually on or around May 1 and November 1 of each year, with our next scheduled redetermination around May 1, 2021. The borrowing base is adjusted at the lenders' discretion and is based, in part, upon external factors over which we have no control. The borrowing base is subject to a reduction by twenty-five percent (25%) of the principal amount of any unsecured or subordinated debt issued or incurred. The borrowing base may also be reduced if we sell borrowing base properties and/or cancel commodity derivative positions with an aggregate value in excess of 5% of the then-effective borrowing base between redeterminations. The Bank Credit Agreement matures on January 30, 2024.

The Bank Credit Agreement prohibits us from paying dividends on our common stock through September 17, 2021. The Bank Credit Agreement also limits our ability to, among other things, incur and repay other indebtedness; grant liens; engage in certain mergers, consolidations, liquidations and dissolutions; engage in sales of assets; make acquisitions and investments; make other restricted payments (including redeeming, repurchasing or retiring our common stock); and enter into commodity derivative agreements, in each case subject to customary exceptions.

The Bank Credit Agreement contains certain financial performance covenants including the following:

- A Consolidated Total Debt to Consolidated EBITDAX covenant, with such ratio not to exceed 3.5 times; and
- A requirement to maintain a current ratio (i.e., Consolidated Current Assets to Consolidated Current Liabilities) of at least 1.0 times.

For purposes of computing the current ratio per the Bank Credit Agreement, Consolidated Current Assets exclude the current portion of derivative assets but include available borrowing capacity under the Bank Credit Agreement, and Consolidated Current Liabilities exclude the current portion of derivative liabilities as well as the current portions of long-term indebtedness outstanding. Under these financial performance covenant calculations, as of December 31, 2020, our ratio of consolidated total debt to consolidated EBITDAX was 0.45 to 1.0 (with a maximum permitted ratio of 3.5 to 1.0) and our current ratio was 3.73 to 1.0 (with a required ratio of not less than 1.0 to 1.0). Based upon our currently forecasted levels of production and costs, hedges in place as of February 24, 2021, and current oil commodity futures prices, we currently anticipate continuing to be in compliance with our financial performance covenants during the foreseeable future.

The above description of our Bank Credit Agreement is qualified by the express language and defined terms contained in the Bank Credit Agreement, which is filed as an exhibit to our Form 8-K Report filed with the SEC on September 18, 2020.

Commitments, Obligations and Off-Balance Sheet Arrangements. As of December 31, 2020, we had a total of $23.0 million of letters of credit outstanding under our senior secured bank credit facility. Additionally, we have obligations for development and exploratory expenditures that arise from our normal capital expenditure program or from other transactions common to our industry, none of which are recorded on our balance sheet. These obligations are further described in *2021 Plans and Capital Budget* above. In addition, in order to recover our undeveloped proved reserves, we must also fund the associated future development costs estimated in our proved reserve reports. For a further discussion of our future development costs, see *Supplemental Oil and Natural Gas Disclosures (Unaudited)* to the consolidated financial statements.

Our periodic obligations include operational expenses that we anticipate being paid out of our cash flow from sale of production, plus the capital expenditures detailed above. In addition to these periodic expenditures, we have various future cash commitments under contracts in place as of December 31, 2020. The most material of these commitments to be settled within the next 12 months include:

- Pipeline financing obligations of $70.0 million associated with the NEJD pipeline system, which is to be repaid in four equal payments during 2021, with the first payment made on January 31, 2021;
- Contracts for the purchase of CO_2 captured from industrial sources that is used in our tertiary recovery activities and processing fees related to our overriding royalty interest in the CO_2 at LaBarge Field (see Note 14, *Commitments and Contingencies*, to the consolidated financial statements for further discussion); and
- Operating lease obligations (see Note 5, *Leases*, to the consolidated financial statements for further discussion).

In addition to these commitments, we have recurring expenditures for such things as accounting, engineering and legal fees; software maintenance; subscriptions; and other overhead-type items. Normally these expenditures do not change materially on an aggregate basis from year to year and are part of our general and administrative expenses. Most of these recurring expenditures could be quickly canceled with regard to any specific vendor, even though the expense itself may be required for our ongoing normal operations. Other commitments include certain transportation agreements and well-related costs. Our longer-term commitments that extend beyond the next 12 months include the following:

- Obligations and periodic interest payments under our senior secured bank credit facility, which matures on January 30, 2024, and of which $70.0 million was outstanding as of December 31, 2020; and
- Asset retirement obligations related to future costs associated with plugging and abandoning our oil, natural gas and CO_2 wells, removing equipment and facilities from leased acreage, and returning land to its original condition (see Note 6, *Asset Retirement Obligations*, to the consolidated financial statements).

As detailed throughout this report, the largest determinant of our cash flow is the oil price we receive. The variability of proceeds from the sale of our production is offset to some extent by similar directional variances in certain expenses, including a portion of our lease operating expenses and production taxes, as these expenses experience some variability with changes in oil prices. Because revenues and expenses do not rise and fall at the same rate, the continuing volatility of the oil market in recent years often results in variances when comparing period-to-period revenues and expense items. Additionally, events in world oil markets can affect cash flow, which we attempt to offset to some extent with our hedging program.

FINANCIAL OVERVIEW OF TERTIARY OPERATIONS

As discussed in Item 1, *Business and Properties – Oil and Natural Gas Operations – Enhanced Oil Recovery Overview*, our tertiary operations represent a significant portion of our overall operations and have become our primary strategic focus. The economics of a tertiary field and the related impact on our financial statements differ from a conventional oil and gas play and are explained further below.

While it is difficult to accurately forecast future production, we believe our tertiary recovery operations provide significant long-term production growth potential at reasonable return metrics, with relatively low risk, assuming crude oil prices are at levels that support the development of those projects. We have been developing tertiary oil properties for over 21 years, and the financial impact of such operations is reflected in our historical financial statements. The summary below highlights our observations regarding how tertiary operations have impacted our financial statements.

Finding and Development Costs. We currently expect finding and development costs (including future development and abandonment costs but excluding CO_2 pipeline infrastructure capital expenditures) over the life of each field to be competitive with the industry average costs for other oil properties. See the definition of finding and development costs in the *Glossary and Selected Abbreviations*.

Timing of Capital Costs. When initiating a new tertiary flood, there generally is a delay between the initial capital expenditures and the resulting production increases. We must build facilities, and often a CO_2 pipeline to the field, before CO_2 flooding can commence, and it usually takes six to twelve months before the field responds to the injection of CO_2 (i.e., oil production commences). Further, we may spend significant amounts of capital before we can recognize any proved reserves from fields we flood and, even after a field has proved reserves, significant amounts of additional capital will usually be required to fully develop the field.

Recognition of Proved Reserves. In order to recognize proved tertiary oil reserves, we must either demonstrate production resulting from the tertiary process or the field must be analogous to an existing tertiary flood. The magnitude of proved reserves that we can book in any given year will depend on our progress with new floods, the timing of the production response from new floods and the performance of our existing floods.

Production Rates. The production rate at a tertiary flood can vary from quarter to quarter, as a tertiary field's production may increase rapidly when wells respond to the CO_2, plateau temporarily, and then resume growth as additional areas of the field are developed. During a tertiary flood life cycle, facility capacity is increased from time to time, which occasionally requires temporary shutdowns during installation, thereby causing temporary declines in production. We also find it difficult to precisely predict when any given well will respond to the injected CO_2, as the CO_2 seldom travels through the rock consistently due to heterogeneity in the oil-bearing formations. With the lower level of oil prices over the past several years, our pace of development has generally slowed, thereby reducing our Company-wide production rates. We find all of these fluctuations to be normal and generally expect oil production at a tertiary field to increase over time until the field is fully developed, albeit sometimes in inconsistent patterns.

Operating Costs. Tertiary projects may be more expensive to operate than traditional industry operations because of the cost of injecting and recycling the CO_2 (primarily due to the cost of the CO_2 and the significant energy requirements to re-compress the CO_2 back into a near-liquid state for re-injection purposes). The costs of our CO_2 and the electricity required to recycle and inject this CO_2 comprise over half of our typical tertiary operating expenses. Since these costs vary along with commodity and commercial electricity prices, they are highly variable and will increase in a high-commodity-price environment and decrease in a low-price environment. The cost of purchasing and/or producing CO_2 for use in tertiary floods is allocated to our tertiary oil fields and recorded as lease operating expenses (following the commencement of tertiary oil production) at the time the CO_2 is injected. These costs have historically represented approximately 20% to 25% of the total operating costs for our tertiary operations. Since we expense all of the operating costs to produce and inject our CO_2 (following the commencement of tertiary oil production), operating costs per barrel for a new flood will be higher at the inception of CO_2 injection projects because of minimal related oil production at that time.

RESULTS OF OPERATIONS

Financial and Operating Results Tables

Certain of our financial results for our Successor and Predecessor periods are included in the following table.

	Successor	Predecessor		
	Period from Sept. 19, 2020 through	Period from Jan. 1, 2020 through	Year Ended December 31,	
In thousands, except per-share data	Dec. 31, 2020	Sept. 18, 2020	2019	2018
Financial results				
Net income (loss)(1)	$ (50,658)	$ (1,432,578)	$ 216,959	$ 322,698
Net income (loss) per common share – basic(1)	(1.01)	(2.89)	0.47	0.75
Net income (loss) per common share – diluted(1)	(1.01)	(2.89)	0.45	0.71
Net cash provided by operating activities	40,326	113,408	494,143	529,685

(1) Includes a pre-tax full cost pool ceiling test write-down of our oil and natural gas properties of $1.0 million for the Successor period September 19, 2020 through December 31, 2020 and $996.7 million for the Predecessor period January 1, 2020 through September 18, 2020. In addition, the Predecessor period January 1, 2020 through September 18, 2020 includes reorganization adjustments, net totaling $850.0 million.

Certain of our financial and operating results and statistics for each of the last three years are included in the following table.

	Year Ended December 31,		
In thousands, except per-share and unit data	2020	2019	2018
Average daily production volumes			
Bbls/d	49,828	56,672	58,532
Mcf/d	7,938	9,246	10,854
BOE/d	51,151	58,213	60,341
Operating revenues			
Oil sales	$ 689,020	$ 1,205,083	$ 1,412,358
Natural gas sales	4,189	6,937	10,231
Total oil and natural gas sales	$ 693,209	$ 1,212,020	$ 1,422,589
Commodity derivative contracts(1)			
Receipt (payment) on settlements of commodity derivatives	$ 102,485	$ 23,606	$ (175,248)
Noncash fair value gains (losses) on commodity derivatives(2)	(62,355)	(93,684)	196,335
Commodity derivatives income (expense)	$ 40,130	$ (70,078)	$ 21,087
Unit prices – excluding impact of derivative settlements			
Oil price per Bbl	$ 37.78	$ 58.26	$ 66.11
Natural gas price per Mcf	1.44	2.06	2.58
Unit prices – including impact of derivative settlements(1)			
Oil price per Bbl	$ 43.40	$ 59.40	$ 57.91
Natural gas price per Mcf	1.44	2.06	2.58
Oil and natural gas operating expenses			
Lease operating expenses	$ 351,505	$ 477,220	$ 489,720
Transportation and marketing expenses	37,759	41,810	43,942
Production and ad valorem taxes	53,708	86,820	96,589
Oil and natural gas operating revenues and expenses per BOE			
Oil and natural gas revenues	$ 37.03	$ 57.04	$ 64.59
Lease operating expenses	18.78	22.46	22.24
Transportation and marketing expenses	2.02	1.97	2.00
Production and ad valorem taxes	2.87	4.09	4.39
CO_2 sources – revenues and expenses			
CO_2 sales and transportation fees	$ 30,468	$ 34,142	$ 31,145
CO_2 operating and discovery expenses	(4,568)	(2,922)	(2,816)
CO_2 revenue and expenses, net	$ 25,900	$ 31,220	$ 28,329

(1) See also *Commodity Derivative Contracts* below and *Market Risk Management* for information concerning our commodity derivative transactions.

(2) Noncash fair value gains (losses) on commodity derivatives is a non-GAAP measure and is different from "Commodity derivatives expense (income)" in the Consolidated Statements of Operations in that the noncash fair value gains (losses) on commodity derivatives represent only the net changes between periods of the fair market values of commodity derivative positions, and exclude the impact of settlements on commodity derivatives during the period, which were receipts on settlements of $102.5 million and $23.6 million for the years ended December 31, 2020 and 2019, respectively, compared to payments on settlements of $175.2 million for the year ended December 31, 2018. We believe that noncash fair value gains (losses) on commodity derivatives is a useful supplemental disclosure to "Commodity derivatives expense (income)" in order to differentiate noncash fair market value adjustments from receipts or payments upon settlements on commodity derivatives during the period. This supplemental disclosure is widely used within the industry and by securities analysts, banks and credit rating agencies in calculating EBITDA and in adjusting net income (loss) to present those measures on a comparative basis across companies, as well as to assess

compliance with certain debt covenants. Noncash fair value gains (losses) on commodity derivatives is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for "Commodity derivatives expense (income)" in the Consolidated Statements of Operations. See also the *Glossary and Selected Abbreviations* for the definition of noncash fair value gains (losses) on commodity derivatives.

Production

Average daily production by area for 2020, 2019 and 2018, and for each of the quarters of 2020, is shown below:

	Average Daily Production (BOE/d)						
	2020 Quarters				Year Ended December 31,		
Operating Area	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	2020	2019	2018
Tertiary oil production							
Gulf Coast region							
Delhi	3,813	3,529	3,208	3,132	3,419	4,324	4,368
Hastings	5,232	4,722	4,473	4,598	4,755	5,403	5,596
Heidelberg	4,371	4,366	4,256	4,198	4,297	4,195	4,355
Oyster Bayou	3,999	3,871	3,526	3,880	3,818	4,345	4,843
Tinsley	4,355	3,788	4,042	3,654	3,959	4,608	5,530
West Yellow Creek	775	695	588	614	668	640	205
Mature properties(1)	6,386	5,249	5,683	5,718	5,759	6,422	6,702
Total Gulf Coast region	28,931	26,220	25,776	25,794	26,675	29,937	31,599
Rocky Mountain region							
Bell Creek	5,731	5,715	5,551	5,079	5,518	5,228	4,113
Salt Creek	2,149	1,386	2,167	2,007	1,928	2,143	2,109
Grieve	50	7	—	—	14	53	7
Total Rocky Mountain region	7,930	7,108	7,718	7,086	7,460	7,424	6,229
Total tertiary oil production	36,861	33,328	33,494	32,880	34,135	37,361	37,828
Non-tertiary oil and gas production							
Gulf Coast region							
Mississippi	748	713	629	655	686	970	960
Texas	3,419	3,087	3,095	2,860	3,115	3,225	3,418
Other	6	5	4	8	6	6	13
Total Gulf Coast region	4,173	3,805	3,728	3,523	3,807	4,201	4,391
Rocky Mountain region							
Cedar Creek Anticline	13,046	11,988	11,485	11,433	11,985	14,090	14,837
Other	1,105	1,069	979	969	1,030	1,262	1,431
Total Rocky Mountain region	14,151	13,057	12,464	12,402	13,015	15,352	16,268
Total non-tertiary production	18,324	16,862	16,192	15,925	16,822	19,553	20,659
Total continuing production	55,185	50,190	49,686	48,805	50,957	56,914	58,487
Property sales							
Property divestitures(2)	780	—	—	—	194	1,299	1,854
Total production	55,965	50,190	49,686	48,805	51,151	58,213	60,341

(1) Mature properties include Brookhaven, Cranfield, Eucutta, Little Creek, Mallalieu, Martinville, McComb and Soso fields.

(2) Includes non-tertiary production related to the March 2020 sale of 50% of our working interests in Webster, Thompson, Manvel, and East Hastings fields, Citronelle Field sold in July 2019 and Lockhart Crossing Field sold in the third quarter of 2018.

Total Production

Total continuing production during 2020 averaged 50,957 BOE/d, including 34,135 Bbls/d from tertiary properties and 16,822 BOE/d from non-tertiary properties. Total continuing production excludes sold production related to our Gulf Coast Working Interests Sale in March 2020 and, for prior-year periods, excludes production from Citronelle Field sold in July 2019 and Lockhart Crossing Field sold in the third quarter of 2018. Our 2020 total continuing production level represents a decrease of 5,957 BOE/d (10%) compared to 2019 levels, most significantly attributable to production that was shut-in due to wells that were uneconomic to produce or repair based on NYMEX oil prices during the second through fourth quarters of 2020. In addition to shut-in production, the year-over-year production decline included production declines at Delhi Field due to the lack of CO_2 purchases between late-February and late-October 2020 as a result of the Delta-Tinsley CO_2 pipeline being down for repair during that period, reduced levels of workovers and capital investment due to lower oil prices and higher than normal declines resulting from such. During the fourth quarter of 2020, the Delta-Tinsley pipeline was brought back into service, allowing CO_2 purchases to resume at Delhi Field. Our production during 2020 was 97% oil, consistent with 2019 and 2018.

Oil and Natural Gas Revenues

Oil and natural gas revenues decreased 43% between 2019 and 2020 and decreased 15% between 2018 and 2019. The changes in our oil and natural gas revenues are due to changes in production quantities and realized commodity prices (excluding any impact of our commodity derivative contracts), as reflected in the following table:

	Year Ended December 31, 2020 vs. 2019		Year Ended December 31, 2019 vs. 2018	
In thousands	Decrease in Revenues	Percentage Decrease in Revenues	Decrease in Revenues	Percentage Decrease in Revenues
Change in oil and natural gas revenues due to:				
Decrease in production	$ (144,118)	(12)%	$ (50,163)	(4)%
Decrease in commodity prices	(374,693)	(31)%	(160,406)	(11)%
Total decrease in oil and natural gas revenues	$ (518,811)	(43)%	$ (210,569)	(15)%

Excluding any impact of our commodity derivative contracts, our average net realized commodity prices and NYMEX differentials were as follows during 2020, 2019 and 2018:

	Year Ended December 31,		
	2020	2019	2018
Average net realized prices			
Oil price per Bbl	$ 37.78	$ 58.26	$ 66.11
Natural gas price per Mcf	1.44	2.06	2.58
Price per BOE	37.03	57.04	64.59
Average NYMEX differentials			
Gulf Coast region			
Oil per Bbl	$ (1.14)	$ 3.30	$ 2.94
Natural gas per Mcf	(0.14)	(0.04)	0.09
Rocky Mountain region			
Oil per Bbl	$ (2.80)	$ (2.01)	$ (1.50)
Natural gas per Mcf	(1.36)	(0.96)	(1.06)
Total Company			
Oil per Bbl	$ (1.81)	$ 1.23	$ 1.30
Natural gas per Mcf	(0.69)	(0.47)	(0.49)

Prices received in a regional market fluctuate frequently and can differ from NYMEX pricing due to a variety of reasons, including supply and/or demand factors, crude oil quality, and location differentials.

- **Gulf Coast Region**. Our average NYMEX oil differential in the Gulf Coast region was a negative $1.14 per Bbl in 2020 and a positive $3.30 per Bbl during 2019. With the recent exception of 2020, our Gulf Coast region differentials have generally been positive to NYMEX due to historically higher prices received for Gulf Coast crudes, such as Light Louisiana Sweet crude oil, though storage constraints and weak demand caused these differentials to weaken significantly during 2020.

- **Rocky Mountain Region.** NYMEX oil differentials in the Rocky Mountain region averaged $2.80 per Bbl below NYMEX during 2020, compared to an average differential of $2.01 per Bbl below NYMEX in 2019. Differentials in the Rocky Mountain region can fluctuate significantly on a month-to-month basis due to weather, refinery or transportation issues, and Canadian and U.S. crude oil price index volatility.

Our realized oil prices and differentials during 2020 have been significantly impacted by the rapid and precipitous drop in oil demand caused by the slowdown in economic activity due to the COVID-19 pandemic. This drop in oil demand followed the early-March 2020 failure by the group of oil producing nations known as OPEC+ to reach an agreement over proposed oil production cuts, causing oil prices to drop to unprecedented levels in the second quarter of 2020. Uncertainty about the duration of the COVID-19 pandemic and its resulting economic consequences has resulted in abnormally high worldwide inventories of produced oil. While oil prices have improved from the low points experienced during the second quarter of 2020, concerns and uncertainties around the balance of supply and demand for oil are expected to continue for some time. While our oil differentials have improved since the second quarter of 2020, oil prices are expected to continue to be volatile as a result of these events, and as changes in oil inventories, oil demand and economic performance are reported.

CO_2 Revenues and Expenses

We sell CO_2 produced from Jackson Dome to third-party industrial users at various contracted prices primarily under long-term contracts. We recognize the revenue received on these CO_2 sales as "CO_2 sales and transportation fees" with the corresponding costs recognized as "CO_2 operating and discovery expenses" in our Consolidated Statements of Operations.

Oil Marketing Revenues and Expenses

From time to time, we market third-party production for sale in exchange for a fee. We recognize the revenue received on these oil sales as "Oil marketing revenues" and the expenses incurred to market and transport the oil as "Oil marketing expenses" in our Consolidated Statements of Operations.

Commodity Derivative Contracts

We routinely enter into oil derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil production and to provide more certainty to our future cash flows. These contracts have historically consisted of price floors, collars, three-way collars, fixed-price swaps, fixed-price swaps enhanced with a sold put, and basis swaps.

The following tables summarize the impact our commodity derivative contracts had on our operating results for the periods indicated:

	Predecessor			Successor		
	Three Months Ended		Period from July 1 through	Period from September 19 through	Three Months Ended	
In thousands	March 31	June 30	September 18	September 30	December 31	Full Year
2020						
Receipt on settlements of commodity derivatives	$ 24,638	$ 45,629	$ 11,129	$ 6,660	$ 14,429	$ 102,485
Noncash fair value gains (losses) on commodity derivatives(1)	122,133	(85,759)	(15,738)	(2,625)	(80,366)	(62,355)
Commodity derivatives income (expense)	$ 146,771	$ (40,130)	$ (4,609)	$ 4,035	$ (65,937)	$ 40,130

	Predecessor				
	Three Months Ended				
In thousands	March 31	June 30	September 30	December 31	Full Year
2019					
Receipt (payment) on settlements of commodity derivatives	$ 8,206	$ (1,549)	$ 8,057	$ 8,892	$ 23,606
Noncash fair value gains (losses) on commodity derivatives(1)	(91,583)	26,309	35,098	(63,508)	(93,684)
Commodity derivatives income (expense)	$ (83,377)	$ 24,760	$ 43,155	$ (54,616)	$ (70,078)
2018					
Payment on settlements of commodity derivatives	$ (33,357)	$ (54,770)	$ (61,611)	$ (25,510)	$ (175,248)
Noncash fair value gains (losses) on commodity derivatives(1)	(15,468)	(41,429)	17,034	236,198	196,335
Commodity derivatives income (expense)	$ (48,825)	$ (96,199)	$ (44,577)	$ 210,688	$ 21,087

(1) Noncash fair value gains (losses) on commodity derivatives is a non-GAAP measure. See *Financial and Operating Results Tables* above for a discussion of the reconciliation between noncash fair value gains (losses) on commodity derivatives to "Commodity derivatives expense (income)" in the Consolidated Statements of Operations. See also the *Glossary and Selected Abbreviations* for the definition of noncash fair value gains (losses) on commodity derivatives.

In order to provide a level of price protection to a portion of our oil production and to meet certain hedging requirements under our Successor senior secured bank credit facility, we have hedged a portion of our estimated oil production in 2021 and 2022 using both NYMEX fixed-price swaps and costless collars. See Note 12, *Commodity Derivative Contracts*, to the consolidated financial statements for additional details of our outstanding commodity derivative contracts as of December 31, 2020, and *Market Risk Management* below for additional discussion. In addition, the following table summarizes our oil derivative contracts as of February 24, 2021:

		Jan. 2021	**Feb. 2021**	**March 2021**	**2Q 2021**	**3Q 2021**	**4Q 2021**	**1H 2022**	**2H 2022**
WTI NYMEX	Volumes Hedged (Bbls/d)	26,000	27,000	29,000	29,000	29,000	29,000	9,500	1,000
Fixed-Price Swaps	Swap Price(1)	$42.54	$42.96	$43.86	$43.86	$43.86	$43.86	$44.24	$50.13
WTI NYMEX	Volumes Hedged (Bbls/d)	3,000	4,000	4,000	4,000	4,000	4,000	1,000	1,000
Collars	Floor / Ceiling Price(1)	$45.00 / $50.95	$46.25 / $53.04	$46.25 / $53.04	$46.25 / $53.04	$46.25 / $53.04	$46.25 / $53.04	$47.50 / $53.00	$47.50 / $53.00
	Total Volumes Hedged (Bbls/d)	29,000	31,000	33,000	33,000	33,000	33,000	10,500	2,000

(1) Averages are volume weighted.

Commodity derivative contracts in place for 2021 include fixed-price swaps and collars. Based on current contracts in place and NYMEX oil futures prices as of February 24, 2021, which averaged approximately $61 per Bbl for the remainder of 2021, we currently expect that we would make cash payments of approximately $185 million during 2021 upon settlement of these contracts, the amount of which is dependent upon fluctuations in future NYMEX oil prices in relation to the prices of our 2021 fixed-price swaps which have a weighted average NYMEX oil price of $43.69 per Bbl. See Note 12, *Commodity Derivative Contracts*, to the consolidated financial statements for further discussion. Changes in commodity prices, expiration of contracts, and new commodity contracts entered into cause fluctuations in the estimated fair value of our oil derivative contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the period-to-period changes in the fair value of these contracts, as outlined above, are recognized in our statements of operations.

Production Expenses

Lease Operating Expenses

	Successor	Predecessor		
	Period from Sept. 19, 2020 through	Period from Jan. 1, 2020 through	Year Ended December 31,	
In thousands, except per-BOE data	Dec. 31, 2020	Sept. 18, 2020	2019	2018
Total lease operating expenses	$ 101,234	$ 250,271	$ 477,220	$ 489,720
Total lease operating expenses per BOE	$ 19.90	$ 18.36	$ 22.46	$ 22.24

Total lease operating expenses were $351.5 million, or $18.78 per BOE, for the combined Predecessor and Successor periods included within the year ended December 31, 2020, compared to $477.2 million, or $22.46 per BOE, during 2019. The decreases on an absolute-dollar basis and per-BOE basis were primarily due to lower expenses across all expense categories, with the largest decreases in labor, workover expense, and power and fuel costs, as well as insurance reimbursements totaling $15.4 million recorded for previously-incurred well control costs, cleanup costs, and damages associated with a 2013 incident at Delhi Field. In response to the significant decline in oil prices in 2020, we implemented cost reduction measures which included shutting down compressors, negotiating reductions with vendors and curtailing well repairs and workovers as most were uneconomic at the lower oil price levels experienced throughout most of 2020.

Currently, our CO_2 expense comprises approximately 20% to 25% of our typical tertiary lease operating expenses, and consists of (1) CO_2 production expenses for the CO_2 reserves we own, and (2) our purchase of CO_2 from royalty and working interest owners and industrial sources for the CO_2 reserves we do not own. During the year ended December 31, 2020, approximately 48% of the CO_2 utilized in our CO_2 floods consisted of CO_2 owned and produced by us (our net revenue interest). The price we pay others for CO_2 varies by source and is generally indexed to oil prices. When combining the production cost of the CO_2 we own with what we pay third parties for CO_2, our average cost of CO_2 during 2020 was approximately $0.38 per Mcf, including taxes paid on CO_2 production but excluding depletion, depreciation and amortization of capital expended at our CO_2 source fields and industrial sources. This per-Mcf CO_2 cost during 2020 was higher than the $0.36 per Mcf comparable measure during 2019 due primarily to higher utilization in our Gulf Coast operations of industrial-sourced CO_2, which has a higher average cost than our naturally occurring CO_2 source.

Transportation and Marketing Expenses

Transportation and marketing expenses primarily consist of amounts incurred related to the transportation, marketing, and processing of oil and natural gas production. Transportation and marketing expenses were $37.8 million for the combined Predecessor and Successor periods included within the year ended December 31, 2020, compared to $41.8 million during 2019. The decrease between periods was primarily due to fewer third-party oil purchases and lower marketing expenses.

Taxes Other than Income

Taxes other than income, which includes production, ad valorem and franchise taxes, were $60.1 million for the combined Predecessor and Successor periods included within the year ended December 31, 2020, compared to $93.8

million for 2019. The decrease between periods was primarily due to a decrease in production taxes resulting from lower oil and natural gas revenues and production levels.

General and Administrative Expenses ("G&A")

	Successor	Predecessor		
	Period from Sept. 19, 2020 through	Period from Jan. 1, 2020 through	Year Ended December 31,	
In thousands, except per-BOE data and employees	Dec. 31, 2020	Sept. 18, 2020	2019	2018
Net cash administrative costs	$ 11,258	$ 41,096	$ 51,932	$ 59,544
Net stock-based compensation	8,212	4,111	12,470	11,951
Severance-related costs	—	3,315	18,627	—
Net G&A expense	$ 19,470	$ 48,522	$ 83,029	$ 71,495
G&A per BOE				
Net cash administrative costs	$ 2.21	$ 3.02	$ 2.44	$ 2.70
Net stock-based compensation	1.62	0.30	0.59	0.55
Severance-related costs	—	0.24	0.88	—
Net G&A expense	$ 3.83	$ 3.56	$ 3.91	$ 3.25
Employees as of period end	657	662	806	847

Our net G&A expense on an absolute-dollar basis was $68.0 million for the combined Predecessor and Successor periods included within the year ended December 31, 2020, a decrease of $15.0 million (18%) from 2019. Excluding severance-related costs from both years results in net G&A expense being essentially even between 2020 and 2019. Severance-related expense of $18.6 million during 2019 was associated with our voluntary separation program, the majority of which was paid out in the first quarter of 2020.

On the Emergence Date and pursuant to the terms of the Plan and the Confirmation Order, a framework for a management incentive plan was adopted, which reserves for officers, other employees, directors and other service providers a pool of shares of new common stock. The 2020 Omnibus Stock and Incentive Plan was adopted on December 2, 2020, and initial awards were granted on December 4, 2020. The initial award grants contained both time-based awards for senior management and directors, vesting over three years, and also contained performance-based awards for senior management, with vesting based upon achieving certain stock price levels over a consecutive 60-trading day period on a volume-weighted average price basis. It is currently estimated that full vesting of the performance awards will be achieved in early March 2021, which resulted in $8.1 million of performance-based stock compensation being expensed in the fourth quarter of 2020 and $16.6 million of performance-based stock compensation expected to be recognized in the first quarter of 2021.

Interest and Financing Expenses

	Successor	Predecessor		
In thousands, except per-BOE data and interest rates	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	Year Ended December 31, 2019	Year Ended December 31, 2018
Cash interest(1)	$ 2,277	$ 108,824	$ 191,454	$ 186,632
Less: interest not reflected as expense for financial reporting purposes(1)	—	(49,243)	(85,454)	(86,111)
Noncash interest expense	799	2,439	4,554	6,246
Amortization of debt discount(2)	—	9,132	7,749	—
Less: capitalized interest	(1,261)	(22,885)	(36,671)	(37,079)
Interest expense, net	$ 1,815	$ 48,267	$ 81,632	$ 69,688
Interest expense, net per BOE	$ 0.36	$ 3.54	$ 3.84	$ 3.16
Average debt principal outstanding(3)	$ 123,120	$ 1,767,605	$ 2,433,245	$ 2,593,035
Average interest rate(4)	6.5 %	8.6 %	7.9 %	7.2 %

(1) Cash interest during the Predecessor periods includes the portion of interest on certain debt instruments accounted for as a reduction of debt for GAAP financial reporting purposes in accordance with FASC 470-60, *Troubled Debt Restructuring by Debtors*. The portion of interest treated as a reduction of debt was related to the Predecessor's 9% Senior Secured Second Lien Notes due 2021 (the "2021 Notes") and 9¼% Senior Secured Second Lien Notes due 2022 (the "2022 Notes") during the Predecessor period from January 1, 2020 through September 18, 2020 and years ended December 31, 2019 and 2018, as well as the Predecessor's previously outstanding 3½% Convertible Senior Notes due 2024 and 5% Convertible Senior Notes due 2023 during 2018. Amounts related to the 2021 Notes and 2022 Notes remaining in future interest payable were written-off to "Reorganization items, net" in the Consolidated Statements of Operations on the Petition Date.

(2) Represents amortization of debt discounts of $3.0 million related to the 7¾% Senior Secured Second Lien Notes due 2024 (the "7¾% Senior Secured Notes") during the Predecessor period January 1, 2020 through September 18, 2020 and $6.1 million related to the 6⅜% Convertible Senior Notes due 2024 (the "2024 Convertible Notes") during the Predecessor period January 1, 2020 through September 18, 2020. Remaining debt discounts were written-off to "Reorganization items, net" in the Consolidated Statements of Operations on the Petition Date.

(3) Excludes debt discounts related to our 7¾% Senior Secured Notes and 2024 Convertible Notes.

(4) Includes commitment fees but excludes debt issue costs and amortization of discount.

Cash interest was $111.1 million for the combined Predecessor and Successor periods included within the year ended December 31, 2020, compared to $191.5 million during 2019. The decrease between periods was primarily due to a decrease in the average debt principal outstanding, with the Successor period reflecting the full extinguishment of all outstanding obligations under the senior secured second lien notes, convertible senior notes, and senior subordinated notes on the Emergence Date, pursuant to the terms of the Plan, relieving approximately $2.1 billion of debt by issuing equity and/or warrants in the Successor period to the holders of that debt.

Depletion, Depreciation, and Amortization ("DD&A")

	Successor	Predecessor		
	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	Year Ended December 31,	
In thousands, except per-BOE data			2019	2018
Oil and natural gas properties	$ 37,188	$ 104,495	$ 159,478	$ 134,486
CO_2 properties, pipelines, plants and other property and equipment	8,624	44,939	74,338	81,963
Accelerated depreciation charge(1)	—	39,159	—	—
Total DD&A	$ 45,812	$ 188,593	$ 233,816	$ 216,449
DD&A per BOE				
Oil and natural gas properties	$ 7.31	$ 7.66	$ 7.51	$ 6.11
CO_2 properties, pipelines, plants and other property and equipment	1.69	3.30	3.49	3.72
Accelerated depreciation charge(1)	—	2.87	—	—
Total DD&A per BOE	$ 9.00	$ 13.83	$ 11.00	$ 9.83
Write-down of oil and natural gas properties	$ 1,006	$ 996,658	$ —	$ —

(1) Represents an accelerated depreciation charge related to capitalized amounts associated with unevaluated properties that were transferred to the full cost pool.

DD&A expense was $234.4 million for the combined Predecessor and Successor periods included within the year ended December 31, 2020, compared to $233.8 million during 2019, with the slight increase due to a $39.2 million accelerated depreciation charge during the Predecessor period from January 1, 2020 through September 18, 2020. The combined Predecessor and Successor period decreases in oil and natural gas properties depletion and CO_2 properties, pipelines, plants and other property and equipment DD&A was primarily due to lower depletable costs due to the step down in book value resulting from fresh start accounting. Our oil and natural gas properties depletion rate was $7.37 per BOE during the fourth quarter of 2020.

Full Cost Pool Ceiling Test

Under full cost accounting rules, we are required each quarter (as well as at the end of the Predecessor period) to perform a ceiling test calculation. Under these rules, the full cost ceiling value is calculated using the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period prior to the end of a particular reporting period. The first-day-of-the-month oil prices for the preceding 12 months, after adjustments for market differentials and transportation expenses by field, averaged $35.84 per Bbl as of December 31, 2020, $40.08 per Bbl as of September 18, 2020, $44.74 per Bbl as of June 30, 2020 and $55.17 per Bbl as of March 31, 2020. While representative oil prices at March 31, 2020 were roughly consistent with adjusted prices used to calculate the December 31, 2019 full cost ceiling value, the decline in NYMEX oil prices in late March 2020 due to OPEC supply pressures and a reduction in worldwide oil demand amid the COVID-19 pandemic contributed to the transfer of $244.9 million of our unevaluated costs to the full cost amortization base during the three months ended March 31, 2020. Primarily as a result of adding these additional costs to the amortization base, we recognized a full cost pool ceiling test write-down of $72.5 million during the three months ended March 31, 2020. In addition, as a result of the precipitous decline in NYMEX oil prices, we recognized additional full cost pool ceiling test write-downs of $662.4 million during the three months ended June 30, 2020, $261.7 million during the period from July 1, 2020 through September 18, 2020, and an additional $1.0 million during the Successor period from September 19, 2020 through December 31, 2020.

Based upon fresh start accounting, oil and gas properties were recorded at fair value as of September 18, 2020. See Note 2, *Fresh Start Accounting*, to the consolidated financial statements for further discussion.

Impairment Assessment of Long-lived Assets

We test long-lived assets for impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. These long-lived assets, which are not subject to our full cost pool ceiling test, are principally comprised of our capitalized CO_2 properties and pipelines, and for the Successor period also included long-term contracts to sell CO_2 to industrial customers. Given the significant declines in NYMEX oil prices to approximately $20 per Bbl in late March 2020 due to OPEC supply pressures and a reduction in worldwide oil demand amid the COVID-19 pandemic, we performed a long-lived asset impairment test for our two long-lived asset groups (Gulf Coast region and Rocky Mountain region) as of March 31, 2020 (Predecessor).

We perform our long-lived asset impairment test by comparing the net carrying costs of our two long-lived asset groups to the respective expected future undiscounted net cash flows that are supported by these long-lived assets which include production of our probable and possible oil and natural gas reserves. The portion of our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves is included in the full cost pool ceiling test as a reduction to future net revenues. The remaining net capitalized costs that are not included in the full cost pool ceiling test, and related intangible assets, are subject to long-lived asset impairment testing. These costs totaled approximately $1.3 billion as of March 31, 2020 (Predecessor). If the undiscounted net cash flows are below the net carrying costs for an asset group, we must record an impairment loss by the amount, if any, that net carrying costs exceed the fair value of the long-lived asset group. The undiscounted net cash flows for our asset groups exceeded the net carrying costs; thus, step two of the impairment test was not required and no impairment was recorded.

Significant assumptions impacting expected future undiscounted net cash flows include projections of future oil and natural gas prices, projections of estimated quantities of oil and natural gas reserves, projections of future rates of production, timing and amount of future development and operating costs, projected availability and cost of CO_2, projected recovery factors of tertiary reserves and risk-adjustment factors applied to the cash flows. We performed a qualitative assessment as of June 30, 2020 and September 18, 2020 (Predecessor periods) and determined there were no material changes to our key cash flow assumptions and no triggering events since the analysis performed as of March 31, 2020; therefore, no impairment test was performed for the second quarter of 2020 or for the period ending September 18, 2020. Upon emergence from bankruptcy, the Company adopted fresh start accounting which resulted in our long-lived assets being recorded at their fair value at the Emergence Date (see Note 2, *Fresh Start Accounting*, to the consolidated financial statements for additional information). We performed a qualitative assessment as of December 31, 2020 (Successor period) and determined there were no material changes to our key cash flow assumptions and no triggering events since the Company's assets were revalued in fresh start accounting as of September 18, 2020; therefore, no impairment test was performed for the fourth quarter of 2020.

Reorganization Items, Net

Reorganization items represent (i) expenses incurred during the Chapter 11 Restructuring subsequent to the Petition Date as a direct result of the Plan, (ii) gains or losses from liabilities settled, and (iii) fresh start accounting adjustments and are recorded in "Reorganization items, net" in our Consolidated Statements of Operations. Professional service provider charges associated with our restructuring that were incurred before the Petition Date and after the Emergence Date are recorded in "Other expenses" in our Consolidated Statements of Operations.

The following table summarizes the losses (gains) on reorganization items, net:

	Predecessor
In thousands	Period from Jan. 1, 2020 through Sept. 18, 2020
Gain on settlement of liabilities subject to compromise	$ (1,024,864)
Fresh start accounting adjustments	1,834,423
Professional service provider fees and other expenses	11,267
Success fees for professional service providers	9,700
Loss on rejected contracts and leases	10,989
Valuation adjustments to debt classified as subject to compromise	757
DIP credit agreement fees	3,107
Acceleration of Predecessor stock compensation expense	4,601
Total reorganization items, net	$ 849,980

Other Expenses

Other expenses totaled $43.9 million for the combined Predecessor and Successor periods included within the year ended December 31, 2020. Other expenses during 2020 primarily are comprised of $28.2 million of professional fees associated with restructuring activities, $5.1 million for the write-off of certain trade receivables, $4.3 million of costs associated with the Delta-Tinsley CO_2 pipeline repair, and $0.9 million of costs associated with the APMTG Helium, LLC helium supply contract ruling (see Note 14, *Commitments and Contingencies – Litigation*, to the consolidated financial statements). The 2019 amounts are primarily comprised of $1.9 million of impairment expense, $1.8 million of costs associated with the Riley Ridge helium supply contract ruling, and $1.6 million of transaction costs associated with the Predecessor's privately negotiated debt exchanges.

Income Taxes

	Successor	Predecessor		
			Year Ended December 31,	
In thousands, except per-BOE amounts and tax rates	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	2019	2018
Current income tax expense (benefit)	$ 30	$ (7,260)	$ 3,881	$ (16,001)
Deferred income tax expense (benefit)	(2,556)	(408,869)	100,471	103,234
Total income tax expense (benefit)	$ (2,526)	$ (416,129)	$ 104,352	$ 87,233
Average income tax expense (benefit) per BOE	$ (0.49)	$ (30.52)	$ 4.91	$ 3.96
Effective tax rate	4.7 %	22.5 %	32.5 %	21.3 %
Total net deferred tax liability	$ 1,274		$ 410,230	$ 309,758

Our income tax provisions for the Predecessor were based on an estimated statutory rate of approximately 25% for 2020, 2019 and 2018. As provided for under FASC 740-270-35-2, we determined the actual effective tax rate for the Predecessor period from January 1, 2020 through September 18, 2020 was the best estimate of our annual effective tax rate. Our effective tax rate for the 2020 Predecessor period was lower than our estimated statutory rate, primarily due to the establishment of a valuation allowance on our federal and state deferred tax assets after the application of fresh start accounting. Our income tax provision for the Successor period was also based on the same estimated statutory rate of approximately 25% but is expected to be near zero, as any tax expense or benefit associated with pre-tax book income or loss will be offset with a change in valuation allowance on our federal and state deferred tax assets. The Successor's effective tax rate of 4.7% was primarily due to adjustments related to our Texas net deferred tax liabilities.

We have evaluated the impact of the Plan, including the change in control, resulting from our emergence from bankruptcy. The cancellation of debt income ("CODI") realized upon emergence is excludable from income and resulted in the elimination of all available federal net operating loss carryforwards and tax credit carryforwards, as well as a partial reduction in tax basis in assets, in accordance with the attribute reduction and ordering rules of Section 108 of the Internal Revenue Code of 1986 (the "Code"). The reduction in the Company's tax attributes for excludable CODI did not occur until the last day of the Company's tax year, December 31, 2020. Accordingly, the tax adjustments recorded in the Predecessor period represented our best estimate using all available information at September 30, 2020. The final tax impacts of the bankruptcy emergence, as well as the Plan's overall effect on the Company's tax attributes which were refined based on the Company's final financial position at December 31, 2020 as required under the Code, resulted in the Company fully reducing its federal net operating loss carryforwards, enhanced oil recovery credits, and research and development tax credits, and reducing a portion of its tax basis in assets.

As the tax basis of our assets, primarily our oil and gas properties, is in excess of the carrying value, as adjusted in fresh start accounting, the Successor is in a net deferred tax asset position at December 31, 2020. We evaluated our deferred tax assets in light of all available evidence as of the balance sheet date, including the tax impacts of the Chapter 11 Restructuring and the full reduction of net operating losses and tax credits and partial reduction of tax basis in assets (collectively "tax attributes"). Given our cumulative loss position and the continued low oil price environment, we recorded a total valuation allowance of $129.4 million on our underlying deferred tax assets, consisting of $54.3 million on our federal deferred tax assets and $75.1 million on our state deferred tax assets as of December 31, 2020. Valuation allowances totaling $60.8 million, $10.2 million, and $4.1 million were recorded for our Louisiana, Mississippi, and other state deferred tax assets, respectively. A $1.3 million state deferred tax liability is recorded on the Successor balance sheet. For the Successor period, the income tax benefit associated with the Successor's pre-tax book loss was substantially offset by a change in valuation allowance.

The current income tax benefit for the Predecessor period ended September 18, 2020 represents amounts estimated to be receivable resulting from alternative minimum tax credits and certain state tax obligations.

Our effective tax rate for 2019 was higher than our estimated statutory rate primarily due to the establishment of a valuation allowance against a portion of our business interest expense deduction that we estimate will be disallowed. Our 2018 effective tax rate was lower than our estimated statutory rate primarily due to tax benefits resulting from enhanced oil recovery income tax credits.

We have $0.6 million of alternative minimum tax credits, which under the Tax Cut and Jobs Act will be refunded in 2021 and are recorded as a receivable on the balance sheet. Our state net operating loss carryforwards expire in various years, starting in 2025. The statutes of limitation for our income tax returns for tax years ending prior to 2017 have lapsed and therefore are not subject to examination by respective taxing authorities.

Per-BOE Data

The following table summarizes our cash flow and results of operations on a per-BOE basis for the comparative periods. Each of the individual components is discussed above.

	Year Ended December 31,		
Per-BOE data	2020	2019	2018
Oil and natural gas revenues	$ 37.03	$ 57.04	$ 64.59
Receipt (payment) on settlements of commodity derivatives	5.47	1.11	(7.96)
Lease operating expenses	(18.78)	(22.46)	(22.24)
Production and ad valorem taxes	(2.87)	(4.09)	(4.39)
Transportation and marketing expenses	(2.02)	(1.97)	(2.00)
Production netback	18.83	29.63	28.00
CO_2 sales, net of operating and discovery expenses	1.39	1.47	1.28
General and administrative expenses[(1)]	(3.63)	(3.91)	(3.25)
Interest expense, net	(2.68)	(3.84)	(3.16)
Reorganization items settled in cash	(2.08)	—	—
Other	(0.38)	0.43	(2.01)
Changes in assets and liabilities relating to operations	(3.24)	(0.52)	3.19
Cash flows from operations	8.21	23.26	24.05
DD&A – excluding accelerated depreciation charge	(10.43)	(11.00)	(9.83)
DD&A – accelerated depreciation charge[(2)]	(2.09)	—	—
Write-down of oil and natural gas properties	(53.29)	—	—
Deferred income taxes	21.98	(4.73)	(4.69)
Gain on extinguishment of debt	1.01	7.34	—
Noncash fair value gains (losses) on commodity derivatives[(3)]	(3.33)	(4.41)	8.92
Noncash reorganization items, net	(43.32)	—	—
Other noncash items	2.03	(0.25)	(3.80)
Net income (loss)	$ (79.23)	$ 10.21	$ 14.65

(1) General and administrative expenses includes an accrual for severance-related costs of $18.6 million associated with our voluntary separation program for the year ended December 31, 2019, which if excluded, would have averaged $3.03 per BOE.

(2) Represents an accelerated depreciation charge related to impaired unevaluated properties that were transferred to the full cost pool.

(3) Noncash fair value gains (losses) on commodity derivatives is a non-GAAP measure. See *Financial and Operating Results Tables* above for a discussion of the reconciliation between noncash fair value gains (losses) on commodity derivatives to "Commodity derivatives expense (income)" in the Consolidated Statements of Operations. See also the *Glossary and Selected Abbreviations* for the definition of noncash fair value gains (losses) on commodity derivatives.

MARKET RISK MANAGEMENT

Debt and Interest Rate Sensitivity

At December 31, 2020, we had $70.0 million of outstanding borrowing under our Bank Credit Agreement. At this level of variable-rate debt, an increase or decrease of 10% in interest rates would have an immaterial effect on our interest expense. Our Bank Credit Agreement does not have any triggers or covenants regarding our debt ratings with rating agencies. The following table presents the principal and fair values of our outstanding debt as of December 31, 2020:

In thousands	2021	2022	2023	2024	Total	Fair Value
Variable rate debt						
Senior Secured Bank Credit Facility (weighted average interest rate of 4.0% at December 31, 2020	$ —	$ —	$ —	$ 70,000	$ 70,000	$ 70,000

Commodity Derivative Contracts

We enter into oil derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil production and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps, fixed-price swaps enhanced with a sold put, and basis swaps. The production that we hedge has varied from year to year depending on our levels of debt, financial strength, and expectation of future commodity prices. Depending on market conditions, we may continue to add to our existing 2021 and 2022 hedges. See also Note 12, *Commodity Derivative Contracts*, and Note 13*, Fair Value Measurements,* to the consolidated financial statements for additional information regarding our commodity derivative contracts. Under the terms of our Successor senior secured bank credit facility, by December 31, 2020, we were required to have hedges in place covering a minimum of 65% of our anticipated crude oil production for the first twelve calendar months between August 1, 2020 through July 31, 2021 and 35% of our anticipated crude oil production for the second twelve month period between August 1, 2021 through July 31, 2022. As of December 31, 2020, we were in compliance with the hedging requirements of our Successor Bank Credit Agreement.

All of the mark-to-market valuations used for our commodity derivatives are provided by external sources. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification. All of our commodity derivative contracts are with parties that are lenders under our senior secured bank credit facility (or affiliates of such lenders). We have included an estimate of nonperformance risk in the fair value measurement of our commodity derivative contracts, which we have measured for nonperformance risk based upon credit default swaps or credit spreads.

For accounting purposes, we do not apply hedge accounting to our commodity derivative contracts. This means that any changes in the fair value of these commodity derivative contracts will be charged to earnings instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings.

At December 31, 2020, our commodity derivative contracts were recorded at their fair value, which was a net liability of $58.8 million, a $62.4 million decrease from the $3.6 million net asset recorded at December 31, 2019. This change is primarily related to the expiration of commodity derivative contracts during 2020, new commodity derivative contracts entered into during 2020 for future periods, and changes in oil futures prices between December 31, 2019 and 2020.

Commodity Derivative Sensitivity Analysis

Based on NYMEX oil futures prices as of December 31, 2020, and assuming both a 10% increase and decrease thereon, we would expect to make payments on our crude oil derivative contracts as shown in the following table:

In thousands	Receipt / (Payment)
Based on:	
Futures prices as of December 31, 2020	$ (59,242)
10% increase in prices	(114,559)
10% decrease in prices	(4,499)

Our commodity derivative contracts are used as an economic hedge of our exposure to commodity price risk associated with anticipated future production. As a result, changes in receipts or payments of our commodity derivative contracts due to changes in commodity prices, as reflected in the above table, would be mostly offset by a corresponding increase or decrease in the cash receipts on sales of our oil production to which those commodity derivative contracts relate.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with generally accepted accounting principles requires that we select certain accounting policies and make certain estimates and judgments regarding the application of those policies. Our significant accounting policies are included in Note 1, *Nature of Operations and Summary of Significant Accounting Policies*, to the consolidated financial statements. These policies, along with the underlying assumptions and judgments by our management in their application, have a significant impact on our consolidated financial statements. Following is a discussion of our most critical accounting estimates, judgments and uncertainties that are inherent in the preparation of our financial statements.

Fresh Start Accounting

Upon emergence from bankruptcy, we met the criteria and were required to adopt fresh start accounting in accordance with FASC Topic 852, *Reorganizations*, which on the Emergence Date resulted in a new entity, the Successor, for financial reporting purposes, with no beginning retained earnings or deficit as of the fresh start reporting date. Fresh start accounting requires that new fair values be established for the Company's assets, liabilities and equity as of the date of emergence from bankruptcy, September 18, 2020. The Emergence Date fair values of the Successor's assets and liabilities differ materially from their recorded values as reflected on the historical balance sheet of the Predecessor and required a number of estimates and judgments to be made. All estimates, assumptions, valuations and financial projections, including the fair value adjustments, financial projections, enterprise value and equity value, are inherently subject to significant uncertainties and the resolution of contingencies beyond our control. Accordingly, there is no assurance that the estimates, assumptions, valuations or financial projections will be realized, and actual results could vary materially. Among the most material of these judgments and estimates that were made were the following:

- Reorganization Value – The reorganization value derived from the range of enterprise values associated with the Plan was allocated to the Company's identifiable tangible and intangible assets and liabilities based on their fair values. The value of the reconstituted entity (i.e., Successor) was based on management projections and the valuation models as determined by the Company's financial advisors in setting an estimated range of enterprise values. With the assistance of third-party valuation advisors, we determined the enterprise and corresponding equity value of the Successor using various valuation approaches and methods, including: (i) income approach using a calculation of the present value of future cash flows based on our financial projections, (ii) the market approach using selling prices of similar assets and (iii) the cost approach.

- Oil and Natural Gas Properties – The fair value of our oil and natural gas properties was determined based on the discounted cash flows expected to be generated from these assets. The computations were based on market conditions and reserves in place as of the Emergence Date.

The fair value analysis was based on the Company's estimated future production rates of proved and probable reserves as prepared by the Company's independent petroleum engineers. Discounted cash flow models were prepared using the estimated future revenues and operating costs for all developed wells and undeveloped properties comprising the proved and probable reserves. Future revenue estimates were based upon estimated future production rates and forward strip oil and natural gas prices as of the Emergence Date through 2024 and escalated for inflation thereafter, adjusted for differentials. Operating costs were adjusted for estimated inflation beginning in year 2025. A risk adjustment factor was applied to each reserve category, consistent with the risk of the category. The discounted cash flow models also included adjustments for income tax expenses.

Discount factors utilized were derived using a weighted average cost of capital computation, which included an estimated cost of debt and equity for market participants with similar geographies and asset development type and varying corporate income tax rates based on the expected point of sale for each property's produced assets. Reserve values were also adjusted for any asset retirement obligations as well as for CO_2 indirect costs not directly allocable to oil fields.

- CO_2 Properties – The fair value of CO_2 properties includes the value of CO_2 mineral rights and associated infrastructure and was determined using the discounted cash flow method under the income approach. After-tax cash flows were forecast based on expected costs to produce and transport CO_2 as provided by management, and income was imputed using a gross-up of costs based on a five-year average historical EBITDA margin for publicly traded companies that primarily develop or produce natural gas. Cash flows were also adjusted for a market participant profit on CO_2 costs, since Denbury charges oil fields for CO_2 use on a cost basis. Cash flows were then discounted using a rate considering reduced risk associated with CO_2 industrial sales.

- Pipelines – The fair values of our pipelines were determined using a combination of the replacement cost method under the cost approach and the discounted cash flow method under the income approach. The replacement cost method considers historical acquisition costs for the assets adjusted for inflation, as well as factors in any potential obsolescence based on the current condition of the assets and the ability of those assets to generate cash flow. For assets valued using the discounted cash flow method, after-tax cash flows were forecast based on expected costs provided by management, and profits were imputed using a gross-up of costs based on a five-year average historical EBITDA margin for publicly traded companies that primarily transport natural gas.

Full Cost Method of Accounting, Depletion and Depreciation and Oil and Natural Gas Properties

Businesses involved in the production of oil and natural gas are required to follow accounting rules that are unique to the oil and gas industry. We apply the full cost method of accounting for our oil and natural gas properties. Another acceptable method of accounting for oil and natural gas production activities is the successful efforts method of accounting. In general, the primary differences between the two methods are related to the capitalization of costs and the evaluation for asset impairment. Under the full cost method, all geological and geophysical costs, exploratory dry holes and delay rentals are capitalized to the full cost pool, whereas under the successful efforts method such costs are expensed as incurred. In the assessment of impairment of oil and natural gas properties, the successful efforts method follows the *Accounting for the Impairment or Disposal of Long-Lived Assets* topic of the FASC, under which the net book value of assets is measured for impairment against the undiscounted future cash flows using commodity prices consistent with management expectations. Under the full cost method, the full cost pool (net book value of oil and natural gas properties) is measured against future cash flows discounted at 10% using the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period through the end of each quarterly reporting period. The financial results for a given period could be substantially different depending on the method of accounting that an oil and gas entity applies. Further, we do not designate our oil and natural gas derivative contracts as hedging instruments for accounting purposes under the *Derivatives and Hedging* topic of the FASC (see below), and as a result, these contracts are not considered in the full cost ceiling test.

We make significant estimates at the end of each period related to accruals for oil and natural gas revenues, production, capitalized costs and operating expenses. We calculate these estimates with our best available data, which includes, among other things, production reports, price posting, information compiled from daily drilling reports and other internal tracking devices, and analysis of historical results and trends. While management is not aware of any required revisions to its estimates, there will likely be future adjustments resulting from such things as revisions in estimated oil and natural gas volumes, changes in ownership interests, payouts, joint venture audits, re-allocations by the purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which will require retroactive application. These types of adjustments cannot be currently estimated or determined and will be recorded in the period during which the adjustment occurs.

Under full cost accounting, the estimated quantities of proved oil and natural gas reserves used to compute depletion and the related present value of estimated future net cash flows therefrom used to perform the full cost ceiling test have a significant impact on the underlying financial statements. The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continued reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure the reported reserve estimates represent the most accurate assessments possible, including the hiring of independent engineers to prepare reported estimates, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in our financial statement disclosures. Over the last three years, annual revisions to our reserve estimates, excluding any revisions related to changes in commodity prices, have averaged approximately 2.2% of the previous year's estimates and have been both positive and negative.

Changes in commodity prices also affect our reserve quantities. These changes in quantities affect our DD&A rate, and the combined effect of changes in quantities and commodity prices impacts our full cost ceiling test calculation. For example, we estimate that a 5% increase in our estimate of proved reserve quantities would have lowered our fourth quarter 2020 oil and natural gas property DD&A rate from $7.37 per BOE to approximately $7.05 per BOE, and a 5% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $7.72 per BOE. Also, reserve quantities and their ultimate values, determined solely by our lenders, are the primary factors in determining the maximum borrowing base under our senior secured bank credit facility, particularly quantities and values of our proved developed producing reserves.

Under full cost accounting rules, we are required each quarter (as well as at the end of the Predecessor period) to perform a ceiling test calculation. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as (1) the present value of estimated future net revenues from proved oil and natural gas reserves before future abandonment costs (discounted at 10%), based on the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period prior to the end of a particular reporting period; plus (2) the cost of properties not being amortized; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) related income tax effects. Our future net revenues from proved oil and natural gas reserves are not reduced for development costs related to the cost of drilling for and developing CO_2 reserves nor those related to the cost of constructing CO_2 pipelines, as we do not have to incur additional costs to develop the proved oil and natural gas reserves. Therefore, we include in the ceiling test, as a reduction of future net revenues, that portion of our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves. The fair value of our oil and natural gas derivative contracts is not included in the ceiling test, as we do not designate these contracts as hedging instruments for accounting purposes. The cost center ceiling test is prepared quarterly.

The average first-day-of-the-month NYMEX oil price used in estimating our proved reserves, after adjustments for market differentials and transportation expenses by field, was $55.55 at December 31, 2019, $40.08 at September 18, 2020 and $35.84 at December 31, 2020. Primarily as a result of these commodity price declines, the Predecessor recognized full cost pool ceiling test write-downs of $996.7 million during the period from January 1, 2020 through September 18, 2020 and an additional full cost pool ceiling test write-down of $1.0 million was recognized during the Successor period from September 19, 2020 through December 31, 2020. We did not record any ceiling test write-downs during the Predecessor periods of 2018 or 2019.

We exclude certain unevaluated costs from the amortization base and full cost ceiling test pending the determination of whether proved reserves can be assigned to such properties. The costs classified as unevaluated are transferred to the full cost amortization base as the properties are developed, tested and evaluated. At least annually, we test these assets for impairment based on an evaluation of management's expectations of future pricing, evaluation of lease expiration terms, and planned project development activities. Given the significant declines in NYMEX oil prices in March and April 2020 due to the oil supply and demand imbalance precipitated by the dramatic fall in demand associated with the COVID-19 pandemic combined with the concurrent OPEC+ decision to increase oil supply, we reassessed our development plans and transferred $244.9 million of our unevaluated costs to the full cost pool during the Predecessor period from January 1, 2020 through September 18, 2020.

Tertiary Injection Costs

Our tertiary operations are conducted in reservoirs that have already produced significant amounts of oil over many years; however, in accordance with the rules for recording proved reserves, we cannot recognize proved reserves associated with enhanced recovery techniques, such as CO_2 injection, until we can demonstrate production resulting from the tertiary process or unless the field is analogous to an existing flood. Our costs associated with the CO_2 we produce (or acquire) and inject are principally our cash out-of-pocket costs of production, transportation and acquisition, and to pay royalties.

We capitalize, as a development cost, injection costs in fields that are in their development stage, which means we have not yet seen incremental oil production due to the CO_2 injections (i.e., a production response). These capitalized development costs will be included in our unevaluated property costs until we are able to recognize proved oil reserves associated with the development project. After we see a production response to the CO_2 injections (i.e., the production stage), injection costs will be expensed as incurred, and any previously deferred unevaluated development costs will become subject to depletion. We capitalized $2.3 million of tertiary injection costs associated with our tertiary projects during the Successor period from September 19, 2020 through December 31, 2020 and $16.2 million during the Predecessor period from January 1, 2020 through September 18, 2020, and we capitalized an additional $19.1 million and $24.5 million during 2019 and 2018, respectively.

Income Taxes

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we finalize our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets. If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of December 31, 2020, we had tax valuation allowances totaling $129.4 million to reduce the carrying value of deferred tax assets related to our federal and state deferred tax assets. As of December 31, 2019, we had tax valuation allowances totaling $77.2 million to reduce the carrying value of deferred tax assets related to our disallowed business interest expense and state deferred income tax assets, and as of December 31, 2018, valuation allowances totaling $51.1 million to reduce the carrying value of our state deferred income tax assets. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized. A 1% increase in our statutory tax rate would have increased our calculated income tax expense (benefit) by approximately ($0.5 million) during the Successor period from September 19, 2020 through December 31, 2020, although any change would be offset by a corresponding change in our valuation allowance, ($18.5 million) during the Predecessor period from January 1, 2020 through September 18, 2020, and $3.2 million and $4.1 million for the years ended December 31, 2019 and 2018, respectively. See Note 9, *Income Taxes*, to the consolidated financial statements and *Results of Operations – Income Taxes* above for further information concerning our income taxes.

Fair Value Estimates

The FASC defines fair value, establishes a framework for measuring fair value and requires disclosures about fair value measurements. It does not require us to make any new fair value measurements, but rather establishes a fair value hierarchy that prioritizes the inputs to the valuation techniques used to measure fair value. Level 1 inputs are given the highest priority in the fair value hierarchy, as they represent observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date, while Level 3 inputs are given the lowest priority, as they represent unobservable inputs that are not corroborated by market data. Valuation techniques that maximize the use of observable inputs are favored. See Note 13, *Fair Value Measurements*, to the consolidated financial statements for disclosures regarding our recurring fair value measurements.

Significant uses of fair value measurements include:

- valuation of the Company's assets, liabilities and equity upon application of fresh start accounting (see *Fresh Start Accounting* above);
- assessment of impairment of long-lived assets; and
- recorded value of commodity derivative instruments.

Impairment Assessment of Long-Lived Assets

We test long-lived assets that are not subject to our quarterly full cost pool ceiling test for impairment, including a portion of our capitalized CO_2 properties and pipelines, and long-term contracts to sell CO_2 to industrial customers, whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The factors we assess to determine if a long-lived asset impairment test is necessary include, among other factors, a significant adverse change in the business climate that could affect the value of a long-lived asset, a significant decrease in the market price of an asset group, a significant adverse change in the extent or manner in which a long-lived asset (asset group) is being used or in its physical condition, or a current-period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset (asset group).

We perform our long-lived asset impairment test by comparing the net carrying costs of our long-lived asset groups to the respective expected future undiscounted net cash flows that are supported by these long-lived assets which include production of our probable and possible oil and natural gas reserves. If the undiscounted net cash flows are below the net carrying costs for an asset group, we must record an impairment loss by the amount, if any, that net carrying costs exceed the fair value of the long-lived asset group. Significant assumptions impacting expected future undiscounted net cash flows include projections of future oil and natural gas prices, projections of estimated quantities of oil and natural gas reserves, projections of future rates of production, timing and amount of future development and operating costs, projected availability and cost of CO_2, projected recovery factors of tertiary reserves and risk-adjustment factors applied to the cash flows. Given the significant declines in NYMEX oil prices to approximately $20 per Bbl in late March 2020 due to OPEC supply pressures and a reduction in worldwide oil demand amid the COVID-19 pandemic, we performed a long-lived asset impairment test for our two long-lived asset groups (Gulf Coast and Rocky Mountain region) as of March 31, 2020 (Predecessor). We performed a qualitative assessment as of June 30, 2020 and September 18, 2020 (Predecessor periods) and determined there were no material changes to our key cash flow assumptions and no triggering events since the analysis performed as of March 31, 2020; therefore, no impairment test was performed for the second quarter of 2020 or for the period ending September 18, 2020. Upon emergence from bankruptcy, the Company adopted fresh start accounting which resulted in our long-lived assets being recorded at their fair value at the Emergence Date (see Note 2, *Fresh Start Accounting*, for additional information). We performed a qualitative assessment as of December 31, 2020 (Successor period) and determined there were no material changes to our key cash flow assumptions and no triggering events since the Company's assets were revalued in fresh start accounting as of September 18, 2020; therefore, no impairment test was performed for the fourth quarter of 2020.

Commodity Derivative Contracts

Historically, we have entered into oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps, fixed-price swaps enhanced with a sold put, and basis swaps. Our derivative financial instruments are recorded on the balance sheet as either an asset or liability measured at fair value. The valuation methods used to measure the fair values of these assets and liabilities require considerable management judgment and estimates to derive the inputs necessary to determine fair value estimates, such as forward prices for commodities, interest rates, volatility factors and credit worthiness, as well as other relevant economic measures. We do not apply hedge accounting to our commodity derivative contracts under the FASC *Derivatives and Hedging* topic; accordingly, changes in the fair value of these instruments are recognized in earnings instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings. While we may experience more volatility in our net income (loss) than if we were to apply hedge accounting treatment as permitted by the FASC *Derivatives and Hedging* topic, we believe that for us, the benefits associated with applying hedge accounting do not outweigh the cost, time and effort to comply with hedge accounting. We estimate that a 10% increase in NYMEX oil futures prices as of December 31, 2020 would increase our estimated payments on our crude oil derivative contracts by $55 million, and a 10% decrease in NYMEX oil futures prices would reduce our estimated payments by $55 million.

Use of Estimates

See Note 1, *Nature of Operations and Summary of Significant Accounting Policies*, to the consolidated financial statements for a discussion of our use of estimates.

Recent Accounting Pronouncements

See Note 1, *Nature of Operations and Summary of Significant Accounting Policies*, to the consolidated financial statements for a discussion of recent accounting pronouncements.

NON-GAAP FINANCIAL MEASURE AND RECONCILIATION

Reconciliation of Standardized Measure to PV-10 Value

PV-10 Value is a non-GAAP measure and is different from the Standardized Measure in that PV-10 Value is a pre-tax number and the Standardized Measure is an after-tax number. The information used to calculate PV-10 Value is derived directly from data determined in accordance with FASC Topic 932. We believe that PV-10 Value is a useful supplemental disclosure to the Standardized Measure because the Standardized Measure can be impacted by a company's unique tax situation, and it is not practical to calculate the Standardized Measure on a property-by-property basis. Because of this, PV-10 Value is a widely used measure within the industry and is commonly used by securities analysts, banks and credit rating agencies to evaluate the estimated future net cash flows from proved reserves on a comparative basis across companies or specific properties. PV-10 Value is commonly used by us and others in our industry to evaluate properties that are bought and sold, to assess the potential return on investment in our oil and natural gas properties, and to perform our impairment testing of oil and natural gas properties. PV-10 Value is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for the Standardized Measure. Our PV-10 Value and the Standardized Measure do not purport to represent the fair value of our oil and natural gas reserves. See also *Glossary and Selected Abbreviations* for the definition of "PV-10 Value" and *Supplemental Oil and Natural Gas Disclosures (Unaudited)* to the consolidated financial statements for additional disclosures about the Standardized Measure.

The following table provides a reconciliation of the Standardized Measure to PV-10 Value for the periods indicated:

	Year Ended December 31,		
In thousands	2020	2019	2018
Standardized Measure (GAAP measure)	$ 654,734	$ 2,261,039	$ 3,351,385
Discounted estimated future income tax	48,346	354,629	673,754
PV-10 Value (non-GAAP measure)	$ 703,080	$ 2,615,668	$ 4,025,139

FORWARD-LOOKING INFORMATION

The data and/or statements contained in this Annual Report on Form 10-K that are not historical facts, including, but not limited to, statements found in the sections entitled "Business and Properties" and "*Management's Discussion and Analysis of Financial Condition and Results of Operations*," are forward-looking statements, as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, our ability to capitalize on emerging from bankruptcy and our ability to succeed on a long-term basis, the extent and length of the drop in worldwide oil demand due to the COVID-19 coronavirus, financial forecasts, future hydrocarbon prices and their volatility, current or future liquidity sources or their adequacy to support our anticipated future activities, possible future write-downs of oil and natural gas reserves, together with assumptions based on current and projected production levels, oil and gas prices and oilfield costs, current or future expectations or estimations of our cash flows or the impact of changes in commodity prices on cash flows, availability of capital, borrowing capacity, price and availability of advantageous commodity derivative contracts or the predicted cash flow benefits therefrom, forecasted capital expenditures, drilling activity or methods, including the timing and location thereof, the nature of any future asset purchases or sales or the timing or proceeds thereof, estimated timing of commencement of CO_2 flooding of particular fields or areas, including Cedar Creek Anticline ("CCA"), or the availability of capital for CCA pipeline construction, or its ultimate cost or date of completion, timing of CO_2 injections and initial production responses in tertiary flooding projects, development activities, finding costs, anticipated future cost savings, capital budgets, interpretation or prediction of formation details, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves and supply and their availability, potential reserves, barrels or percentages of recoverable original oil in place, the impact of regulatory rulings or changes, outcomes of pending litigation, prospective legislation affecting the oil and gas industry, environmental regulations, mark-to-market values, competition, rates of return, estimated costs, changes in costs, future capital expenditures and overall economics, worldwide economic conditions, and other variables surrounding operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "forecast," "to our knowledge," "anticipate," "projected," "preliminary," "should," "assume," "believe," "may" or other words that convey, or are intended to convey, the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates, and assumptions and is subject to a number of risks and uncertainties that could significantly and adversely affect current plans, anticipated actions, the timing of such actions and our financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by us or on our behalf. Among the factors that could cause actual results to differ materially are fluctuations in worldwide oil prices or in U.S. oil prices and consequently in the prices received or demand for our oil and natural gas; decisions as to production levels and/or pricing by OPEC or production levels by U.S. shale producers in future periods; levels of future capital expenditures; success of our risk management techniques; accuracy of our cost estimates; access to and terms of credit in the commercial banking or other debt markets; fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards and remediation costs; disruption of operations and damages from well incidents, hurricanes, tropical storms, floods, forest fires, or other natural occurrences; acquisition risks; requirements for capital or its availability; conditions in the worldwide financial, trade and credit markets; general economic conditions; competition; government regulations, including changes in tax or environmental laws or regulations; and unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or that are otherwise discussed in this annual report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in our other public reports, filings and public statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The information required by Item 7A is set forth under *Market Risk Management* in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

Item 8. Financial Statements and Supplementary Information

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Denbury Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheet of Denbury Inc. and its subsidiaries (Successor) (the "Company") as of December 31, 2020 and the related consolidated statements of operations, of changes in stockholders' equity and of cash flows for the period from September 19, 2020 through December 31, 2020, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2020, 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2020, and the results of its operations and its cash flows for the period from September 19, 2020 to December 31, 2020 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the COSO.

Basis of Accounting

As discussed in Note 1 to the consolidated financial statements, the United States Bankruptcy Court for the Southern District of Texas confirmed the Company's prepackaged joint plan of reorganization ("the plan") on September 2, 2020. Confirmation of the plan resulted in the discharge of all claims against the Company that arose before July 30, 2020 and terminates all rights and interests of equity security holders as provided for in the plan. The plan was substantially consummated on September 18, 2020 and the Company emerged from bankruptcy. In connection with its emergence from bankruptcy, the Company adopted fresh start accounting as of September 18, 2020.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our 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 the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audit of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated 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.

The Impact of Proved Oil and Natural Gas Reserves on Net Proved Oil and Natural Gas Properties

The Company's net property and equipment balance, which includes net proved oil and natural gas properties, was $1,303.8 million as of December 31, 2020, depletion, depreciation and amortization (DD&A) expense for the period from September 19, 2020 to December 31, 2020 was $45.8 million, and write-down of oil and natural gas properties from September 19, 2020 to December 31, 2020 was $1.0 million. As described in Note 1, the Company follows the full cost method of accounting for oil and gas properties. Under this method, all costs related to the acquisition, exploration and development of oil and natural gas reserves are capitalized and accumulated into a single cost center. The costs capitalized, including production equipment and future development costs, are depleted or depreciated using the unit-of-production method based on proved oil and natural gas reserves. As disclosed by management, under full cost accounting rules, management is required each quarter to perform a ceiling test calculation. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as (1) the present value of estimated future net revenues from proved oil and natural gas reserves before future abandonment costs (discounted at 10%), based on the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period prior to the end of a particular reporting period; plus (2) the cost of properties not being amortized; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) related income tax effects. The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continued reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Estimating quantities of proved oil and natural gas reserves requires interpretations of available technical data and various assumptions, including future production rates, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, and the assumed effect of governmental rules and regulations. Net proved oil and natural gas reserve estimates are determined by the Company's internal reservoir engineering team and independent petroleum engineers (collectively "specialists").

The principal considerations for our determination that performing procedures relating to the impact of proved oil and natural gas reserves on net proved oil and natural gas properties is a critical audit matter are (i) the significant judgment by management, including the use of specialists, when developing the estimates of proved oil and natural gas reserves, which in turn led to (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence obtained related to the data, methods, and assumptions used by management and its specialists in developing the estimates of proved oil and natural gas reserves and the assumptions applied to the cost center ceiling test related to future production rates.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved oil and natural gas reserves and ceiling test calculation. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the proved oil and natural gas reserves and the reasonableness of the future production rates applied in the cost center ceiling test. As a basis for using this work, the specialists' qualifications were understood and the company's relationship with the specialists was assessed. The procedures performed included evaluation of the methods and assumptions used by the specialists, tests of the data used by the specialists, and an evaluation of the specialists' findings.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
March 5, 2021

We have served as the Company's auditor since 2004.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Denbury Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Denbury Resources Inc. and its subsidiaries (Predecessor) (the "Company") as of December 31, 2019, and the related consolidated statements of operations, of changes in stockholders' equity and of cash flows for the period from January 1, 2020 through September 18, 2020, and for each of the two years in the period ended December 31, 2019 including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019, and the results of its operations and its cash flows for the period from January 1, 2020 to September 18, 2020, and for each of the two years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Basis of Accounting

As discussed in Note 1 to the consolidated financial statements, the Company filed petitions on July 30, 2020 with the United States Bankruptcy Court for the Southern District of Texas for reorganization under the provisions of Chapter 11 of the Bankruptcy Code. The Company's prepackaged joint plan of reorganization was substantially consummated on September 18, 2020 and the Company emerged from bankruptcy. In connection with its emergence from bankruptcy, the Company adopted fresh start accounting. This matter is also described in the "Critical Audit Matters" section of our report.

Change in Accounting Principle

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

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

We conducted our audits of these consolidated financial statements 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 consolidated 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 consolidated 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 consolidated 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

The Impact of Proved Oil and Natural Gas Reserves on Net Proved Oil and Natural Gas Properties

As described in Note 2 to the consolidated financial statements, the Company's net property and equipment balance, which includes net proved oil and natural gas properties, was $1,311.6 million as of September 18, 2020, depletion, depreciation and amortization (DD&A) expense for the period from January 1, 2020 to September 18, 2020 was $188.6 million, and write-down of oil and natural gas properties for the period from January 1, 2020 to September 18, 2020 was $996.7 million. As described in Note 1, the Company follows the full cost method of accounting for oil and gas properties. Under this method, all costs related to the acquisition, exploration and development of oil and natural gas reserves are capitalized and accumulated into a single cost center. The costs capitalized, including production equipment and future development costs, are depleted or depreciated using the unit-of-production method based on proved oil and natural gas reserves. As disclosed by management, under full cost accounting rules, management is required each quarter to perform a ceiling test calculation. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as (1) the present value of estimated future net revenues from proved oil and natural gas reserves before future abandonment costs (discounted at 10%), based on the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period prior to the end of a particular reporting period; plus (2) the cost of properties not being amortized; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) related income tax effects. The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continued reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Estimating quantities of proved oil and natural gas reserves requires interpretations of available technical data and various assumptions, including future production rates, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, and the assumed effect of governmental rules and regulations. Net proved oil and natural gas reserve estimates are determined by the Company's internal reservoir engineering team and independent petroleum engineers (collectively "specialists").

The principal considerations for our determination that performing procedures relating to the impact of proved oil and natural gas reserves on net proved oil and natural gas properties is a critical audit matter are (i) the significant judgment by management, including the use of specialists, when developing the estimates of proved oil and natural gas reserves, which in turn led to (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence obtained related to the data, methods, and assumptions used by management and its specialists in developing the estimates of proved oil and natural gas reserves and the assumptions applied to the cost center ceiling test related to future production rates.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the proved oil and natural gas reserves and the reasonableness of the future production rates applied in the cost center ceiling test. As a basis for using this work, the specialists' qualifications were understood and the company's relationship with the specialists was assessed. The procedures performed included evaluation of the methods and assumptions used by the specialists, tests of the data used by the specialists, and an evaluation of the specialists' findings.

Fresh Start Fair Value Adjustments to Proved Oil and Natural Gas Properties

As described above and in Notes 1 and 2 to the consolidated financial statements, Denbury Inc. (Successor) became the successor reporting company of Denbury Resources Inc. (Predecessor) upon the emergence from bankruptcy on September 18, 2020. During the Predecessor period, the Company applied generally accepted accounting principles for reorganizations, which requires the financial statements for periods subsequent to the commencement of the Chapter 11 Restructuring on July 30, 2020 to distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Upon emergence from bankruptcy, the Company was required to adopt fresh start accounting. Fresh start accounting requires that new fair values be established for the Company's assets, liabilities and equity as of the date of emergence from bankruptcy, September 18, 2020. The Company's reorganization items, net was $850.0 million for the period from January 1, 2020 through September 18, 2020, which included fresh start fair value adjustments to proved oil and natural gas properties of $10,941.3 million. The Company determined the fair value of its oil and gas properties based on discounted cash flows. The fair value analysis was based on the Company's estimated future production rates of proved and probable reserves as prepared by the Company’s independent petroleum engineers. Discounted cash flow models were prepared using the estimated future revenues and operating costs for all developed wells and undeveloped properties comprising the proved and probable reserves. Future revenues were based upon future production rates and forward strip oil and natural gas prices. Operating costs were adjusted for inflation beginning in year 2025. A risk adjustment factor was applied to each reserve category, consistent with the risk of the category. The discounted cash flow models also included adjustments for income tax expenses. Discount factors utilized were derived using a weighted average cost of capital computation, which included an estimated cost of debt and equity for market participants with similar geographies and asset development type and varying corporate income tax rates based on the expected point of sale for each property’s produced assets.

The principal considerations for our determination that performing procedures relating to the fresh start fair value adjustments to proved oil and natural gas properties is a critical audit matter are (i) the significant judgment by management, including the use of specialists, when developing the fresh start fair value adjustments of proved oil and natural gas properties; (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating management’s significant assumptions related to future production rates, forward strip oil and natural gas pricing, operating costs, capital expenditures, and weighted average cost of capital; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included, among others (i) evaluating the appropriateness of the discounted cash flow model; (ii) testing the completeness and accuracy of underlying data used in the discounted cash flow model; and (iii) evaluating the significant assumptions used by management related to future production rates, forward strip oil and natural gas pricing, operating costs, capital expenditures, and weighted average cost of capital. The work of specialists was used in performing the procedures to evaluate the reasonableness of estimates of proved oil and natural gas reserves as stated in the Critical Audit Matter titled “The Impact of Proved Oil and Natural Gas Reserves on Net Proved Oil and Natural Gas Properties” and the reasonableness of the future production rates used in the discounted cash flow models. As a basis for using this work, the specialists’ qualifications were understood and the company’s relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by the specialists, tests of the data used by the specialists and an evaluation of the specialists’ findings. Evaluating the reasonableness of management’s assumptions relating to forward strip oil and natural gas pricing, operating costs, and capital expenditures involved evaluating whether the assumptions used by management were reasonable considering the current and past performance of the Company, the consistency with external market and industry data, and whether the assumptions were consistent with evidence obtained in other areas of the audit. Professionals with specialized skill and knowledge were used to assist in assessing the appropriateness of the discounted cash flow models and the reasonableness of the weighted average cost of capital.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
March 5, 2021

We have served as the Company’s auditor since 2004.

Denbury Inc.
Consolidated Balance Sheets
(In thousands, except par value and share data)

	Successor		Predecessor	
	December 31, 2020		December 31, 2019	
Assets				
Current assets				
Cash and cash equivalents	$	518	$	516
Restricted cash		1,000		—
Accrued production receivable		91,421		139,407
Trade and other receivables, net		19,682		18,318
Derivative assets		187		11,936
Prepaids		14,038		10,434
Total current assets		126,846		180,611
Property and equipment				
Oil and natural gas properties (using full cost accounting)				
Proved properties		851,208		11,447,680
Unevaluated properties		85,304		872,910
CO_2 properties		188,288		1,198,846
Pipelines		133,485		2,329,078
Other property and equipment		86,610		212,334
Less accumulated depletion, depreciation, amortization and impairment		(41,095)		(11,688,020)
Net property and equipment		1,303,800		4,372,828
Operating lease right-of-use assets		20,342		34,099
Intangible assets, net		97,362		22,139
Other assets		86,408		82,190
Total assets	$	1,634,758	$	4,691,867

See accompanying Notes to Consolidated Financial Statements.

Denbury Inc.
Consolidated Balance Sheets
(In thousands, except par value and share data)

	Successor	Predecessor
	December 31, 2020	December 31, 2019
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 112,671	$ 183,832
Oil and gas production payable	49,165	62,869
Derivative liabilities	53,865	8,346
Current maturities of long-term debt (including future interest payable of $0 and $86,054, respectively – see Note 8)	68,008	102,294
Operating lease liabilities	1,350	6,901
Total current liabilities	285,059	364,242
Long-term liabilities		
Long-term debt, net of current portion (including future interest payable of $0 and $78,860, respectively – see Note 8)	70,000	2,232,570
Asset retirement obligations	179,338	177,108
Derivative liabilities	5,087	—
Deferred tax liabilities, net	1,274	410,230
Operating lease liabilities	19,460	41,932
Other liabilities	20,872	53,526
Total long-term liabilities	296,031	2,915,366
Commitments and contingencies (Note 14)		
Stockholders' equity		
Predecessor preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding	—	—
Predecessor common stock, $.001 par value, 750,000,000 shares authorized; 508,065,495 shares issued	—	508
Predecessor paid-in capital in excess of par	—	2,739,099
Predecessor treasury stock, at cost, 1,652,771 shares	—	(6,034)
Successor preferred stock, $.001 par value, 50,000,000 shares authorized, none issued and outstanding	—	—
Successor common stock, $.001 par value, 250,000,000 shares authorized; 49,999,999 shares issued	50	—
Successor paid-in capital in excess of par	1,104,276	—
Accumulated deficit	(50,658)	(1,321,314)
Total stockholders' equity	1,053,668	1,412,259
Total liabilities and stockholders' equity	$ 1,634,758	$ 4,691,867

See accompanying Notes to Consolidated Financial Statements.

Denbury Inc.
Consolidated Statements of Operations
(In thousands, except per-share data)

	Successor	Predecessor		
	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	Year Ended December 31, 2019	Year Ended December 31, 2018
Revenues and other income				
Oil, natural gas, and related product sales	$ 201,108	$ 492,101	$ 1,212,020	$ 1,422,589
CO_2 sales and transportation fees	9,419	21,049	34,142	31,145
Oil marketing revenues	5,376	8,543	14,198	1,921
Other income	4,697	8,419	14,523	17,970
Total revenues and other income	220,600	530,112	1,274,883	1,473,625
Expenses				
Lease operating expenses	101,234	250,271	477,220	489,720
Transportation and marketing expenses	10,595	27,164	41,810	43,942
CO_2 operating and discovery expenses	1,976	2,592	2,922	2,816
Taxes other than income	16,584	43,531	93,752	104,670
Oil marketing expenses	5,318	8,399	14,124	1,676
General and administrative expenses	19,470	48,522	83,029	71,495
Interest, net of amounts capitalized of $1,261, $22,885, $36,671 and $37,079, respectively	1,815	48,267	81,632	69,688
Depletion, depreciation, and amortization	45,812	188,593	233,816	216,449
Commodity derivatives expense (income)	61,902	(102,032)	70,078	(21,087)
Gain on debt extinguishment	—	(18,994)	(155,998)	—
Write-down of oil and natural gas properties	1,006	996,658	—	—
Reorganization items, net	—	849,980	—	—
Other expenses	8,072	35,868	11,187	84,325
Total expenses	273,784	2,378,819	953,572	1,063,694
Income (loss) before income taxes	(53,184)	(1,848,707)	321,311	409,931
Income tax provision (benefit)	(2,526)	(416,129)	104,352	87,233
Net income (loss)	$ (50,658)	$ (1,432,578)	$ 216,959	$ 322,698
Net income (loss) per common share				
Basic	$ (1.01)	$ (2.89)	$ 0.47	$ 0.75
Diluted	$ (1.01)	$ (2.89)	$ 0.45	$ 0.71
Weighted average common shares outstanding				
Basic	50,000	495,560	459,524	432,483
Diluted	50,000	495,560	510,341	456,169

See accompanying Notes to Consolidated Financial Statements.

Denbury Inc.
Consolidated Statements of Cash Flows
(In thousands)

	Successor	Predecessor		
	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	Year Ended December 31, 2019	Year Ended December 31, 2018
Cash flows from operating activities				
Net income (loss)	$ (50,658)	$ (1,432,578)	$ 216,959	$ 322,698
Adjustments to reconcile net income (loss) to cash flows from operating activities				
Noncash reorganization items, net	—	810,909	—	—
Depletion, depreciation, and amortization	45,812	188,593	233,816	216,449
Write-down of oil and natural gas properties	1,006	996,658	—	—
Deferred income taxes	(2,556)	(408,869)	100,471	103,234
Stock-based compensation	8,212	4,111	12,470	11,951
Commodity derivatives expense (income)	61,902	(102,032)	70,078	(21,087)
Receipt (payment) on settlements of commodity derivatives	21,089	81,396	23,606	(175,248)
Gain on debt extinguishment	—	(18,994)	(155,998)	—
Debt issuance costs and discounts	799	11,571	12,303	6,246
Other, net	(2,349)	439	(8,596)	(4,725)
Changes in assets and liabilities, net of effects from acquisitions				
Accrued production receivable	21,411	26,575	(13,619)	20,547
Trade and other receivables	15,567	(22,343)	9,379	16,094
Other current and long-term assets	(1,795)	743	7,629	(6,827)
Accounts payable and accrued liabilities	(67,167)	(16,102)	(3,275)	13,008
Oil and natural gas production payable	(6,912)	(6,792)	2,170	(15,300)
Other liabilities	(4,035)	123	(13,250)	42,645
Net cash provided by operating activities	40,326	113,408	494,143	529,685
Cash flows from investing activities				
Oil and natural gas capital expenditures	(17,964)	(99,582)	(262,005)	(316,647)
CO_2 capital expenditures	(269)	(196)	(3,154)	(5,878)
Pipelines and plants capital expenditures	(618)	(11,601)	(27,319)	(23,108)
Net proceeds from sales of oil and natural gas properties and equipment	938	41,322	10,196	7,762
Other	16,029	12,943	12,590	4,595
Net cash used in investing activities	(1,884)	(57,114)	(269,692)	(333,276)
Cash flows from financing activities				
Bank repayments	(190,000)	(551,000)	(925,791)	(1,982,653)
Bank borrowings	120,000	691,000	925,791	1,507,653
Interest payments treated as a reduction of debt	—	(46,417)	(85,303)	(79,606)
Proceeds from issuance of senior secured notes	—	—	—	450,000
Cash paid in conjunction with debt exchange	—	—	(136,427)	—
Cash paid in conjunction with debt repurchases	—	(14,171)	—	—
Costs of debt financing	(8)	(12,482)	(11,065)	(16,060)
Pipeline financing and capital lease debt repayments	(22,938)	(51,792)	(13,908)	(23,300)
Other	1,638	(9,363)	348	(13,486)
Net cash provided by (used in) financing activities	(91,308)	5,775	(246,355)	(157,452)
Net increase (decrease) in cash, cash equivalents, and restricted cash	(52,866)	62,069	(21,904)	38,957
Cash, cash equivalents, and restricted cash at beginning of period	95,114	33,045	54,949	15,992
Cash, cash equivalents, and restricted cash at end of period	$ 42,248	$ 95,114	$ 33,045	$ 54,949

See accompanying Notes to Consolidated Financial Statements.

Denbury Inc.
Consolidated Statements of Changes in Stockholders' Equity
(Dollar amounts in thousands)

	Common Stock ($.001 Par Value)		Paid-In Capital in Excess of Par	Retained Earnings (Accumulated Deficit)	Treasury Stock (at cost)		Total Equity
	Shares	Amount			Shares	Amount	
Balance – December 31, 2017 (Predecessor)	402,549,346	$ 403	$ 2,507,828	$ (1,855,810)	457,041	$ (4,256)	$ 648,165
Issued pursuant to stock compensation plans	4,556,424	4	(4)	—	—	—	—
Issued pursuant to notes conversion	55,249,955	55	161,949	—	—	—	162,004
Stock-based compensation	—	—	15,438	—	—	—	15,438
Tax withholding for stock compensation plans	—	—	—	—	1,484,708	(6,528)	(6,528)
Net income	—	—	—	322,698	—	—	322,698
Balance – December 31, 2018 (Predecessor)	462,355,725	462	2,685,211	(1,533,112)	1,941,749	(10,784)	1,141,777
Issued pursuant to stock compensation plans	9,315,016	9	(9)	—	—	—	—
Issued pursuant to directors' compensation plan	97,537	—	—	—	—	—	—
Issued pursuant to senior subordinated notes exchanges	36,297,217	37	37,409	(5,161)	(1,990,000)	7,270	39,555
Stock-based compensation	—	—	16,488	—	—	—	16,488
Tax withholding for stock compensation plans	—	—	—	—	1,701,022	(2,520)	(2,520)
Net income	—	—	—	216,959	—	—	216,959
Balance – December 31, 2019 (Predecessor)	508,065,495	508	2,739,099	(1,321,314)	1,652,771	(6,034)	1,412,259
Issued pursuant to stock compensation plans	312,516	—	—	—	—	—	—
Issued pursuant to directors' compensation plan	37,367	—	—	—	—	—	—
Stock-based compensation	—	—	14,317	—	—	—	14,317
Issued pursuant to notes conversion	7,372,250	8	11,493	—	—	—	11,501
Canceled pursuant to stock compensation plans	(6,313,884)	(6)	6	—	—	—	—
Tax withholding for stock compensation plans	—	—	—	—	742,862	(168)	(168)
Net loss	—	—	—	(1,432,578)	—	—	(1,432,578)
Cancellation of Predecessor equity	(509,473,744)	(510)	(2,764,915)	2,753,892	(2,395,633)	6,202	(5,331)
Issuance of Successor equity	49,999,999	50	1,095,369	—	—	—	1,095,419
Balance – September 18, 2020 (Predecessor)	49,999,999	$ 50	$ 1,095,369	$ —	—	$ —	$ 1,095,419
Balance – September 19, 2020 (Successor)	49,999,999	$ 50	$ 1,095,369	$ —	—	$ —	$ 1,095,419
Stock-based compensation	—	—	8,907	—	—	—	8,907
Net loss	—	—	—	(50,658)	—	—	(50,658)
Balance – December 31, 2020 (Successor)	49,999,999	$ 50	$ 1,104,276	$ (50,658)	—	$ —	$ 1,053,668

See accompanying Notes to Consolidated Financial Statements.

Note 1. Nature of Operations and Summary of Significant Accounting Policies

Organization and Nature of Operations

Denbury Inc. ("Denbury," "Company" or the "Successor"), a Delaware corporation, is an independent energy company with operations focused on producing oil from mature oil fields in the Gulf Coast and Rocky Mountain regions. The Company is differentiated by its focus on CO_2 EOR and the emerging CCUS industry, supported by the Company's CO_2 EOR technical and operational expertise and its extensive CO_2 pipeline infrastructure. The utilization of captured industrial-sourced CO_2 in EOR significantly reduces the carbon footprint of the oil that Denbury produces, underpinning the Company's goal to fully offset its Scope 1, 2, and 3 CO_2 emissions within the decade.

As further described in *Emergence from Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code* below, Denbury Inc. became the successor reporting company of Denbury Resources Inc. (the "Predecessor") upon the Predecessor's emergence from bankruptcy on September 18, 2020. References to "Successor" relate to the financial position and results of operations of the Company subsequent to September 18, 2020, and references to "Predecessor" relate to the financial position and results of operations of the Company prior to, and including, September 18, 2020. On September 18, 2020, Denbury filed the Third Restated Certificate of Incorporation with the Delaware Secretary of State to effect a change of the Company's corporate name from Denbury Resources Inc. to Denbury Inc., and on September 21, 2020, the Successor's new common stock commenced trading on the New York Stock Exchange under the ticker symbol DEN.

Emergence from Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code

On July 28, 2020, Denbury Resources Inc. and its subsidiaries entered into a Restructuring Support Agreement (the "RSA") with lenders holding 100% of the revolving loans under our pre-petition revolving bank credit facility and debtholders holding approximately 67.1% of our senior secured second lien notes and approximately 73.1% of our convertible senior notes, which contemplated a restructuring of the Company pursuant to a prepackaged joint plan of reorganization (the "Plan"). On July 30, 2020 (the "Petition Date"), Denbury Resources Inc. and its subsidiaries filed petitions for reorganization in a "prepackaged" voluntary bankruptcy (the "Chapter 11 Restructuring") under chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court") under the caption "*In re Denbury Resources Inc., et al.*, Case No. 20-33801". On September 2, 2020, the Bankruptcy Court entered an order (the "Confirmation Order") confirming the Plan and approving the Disclosure Statement, and on September 18, 2020 (the "Emergence Date"), the Plan became effective in accordance with its terms and the Company emerged from Chapter 11. On the Emergence Date and pursuant to the terms of the Plan and the Confirmation Order, all outstanding obligations under the senior secured second lien notes, convertible senior notes, and senior subordinated notes were fully extinguished, relieving approximately $2.1 billion of debt by issuing equity and/or warrants in the Successor to the former holders of that debt, and the Company:

- Adopted an amended and restated certificate of incorporation and bylaws which reserved for issuance 250,000,000 shares of common stock, par value $0.001 per share, of Denbury (the "New Common Stock") and 50,000,000 shares of preferred stock, par value $0.001 per share;
- Cancelled all outstanding senior secured second lien notes, convertible senior notes, and senior subordinated notes issued by the Predecessor. In accordance with the Plan, claims against and interests in the Predecessor were treated as follows:
    - Holders of secured pipeline lease claims received payment in full in cash, the collateral securing such pipeline lease claim, reinstatement, or such other treatment rendering such pipeline lease claim unimpaired (see Note 8, *Long-Term Debt – Restructuring of Pipeline Financing Transactions*, for discussion of subsequent pipeline transactions);
    - Holders of senior secured second lien notes claims received their pro rata share of 47,499,999 shares representing 95% of the New Common Stock issued on the Emergence Date, subject to dilution on account of warrants and a management incentive plan;
    - Holders of convertible senior notes claims received their pro rata share of (a) 2,500,000 shares representing 5% of the New Common Stock issued on the Emergence Date, subject to dilution on

account of warrants and a management incentive plan and (b) 100% of the series A warrants (see below), reflecting up to a maximum of 5% ownership stake in the reorganized company's equity interests;
    - Holders of subordinated notes claims received their pro rata share of 54.55% of the series B warrants (see below), reflecting up to a maximum of 3% of the reorganized company's equity interests after giving effect to the exercise of the series A warrants;
    - Holders of existing equity interests received their pro rata share of 45.45% of the series B warrants (see below), reflecting up to a maximum of 2.5% of the reorganized company's equity interests after giving effect to the exercise of the series A warrants;
    - Issued 2,631,579 series A warrants at an exercise price of $32.59 per share to former holders of the Predecessor's convertible senior notes and 2,894,740 series B warrants at an exercise price of $35.41 per share to former holders of the Predecessor's senior subordinated notes and Predecessor's equity interests; and
    - Holders of general unsecured claims received payment in full in cash, reimbursement, or such other treatment rendering such general unsecured claim unimpaired.

- Entered into a new senior secured revolving credit agreement with a syndicate of banks (the "Successor Bank Credit Agreement") with total aggregate commitments of $575 million;
- Appointed a new board of directors (the "Board") consisting of four new independent members: Anthony Abate, Caroline Angoorly, Brett Wiggs and James N. "Jim" Chapman, and three continuing members: Dr. Kevin O. Meyers (Chairman of the Board), Lynn A. Peterson and Chris Kendall, Denbury's President and Chief Executive Officer; and
- Adopted a framework for a management incentive plan which reserves for officers, other employees, directors and other service providers a pool of shares of New Common Stock, with initial awards issued on December 4, 2020 (see Note 11, *Stock Compensation*, for further discussion).

During the Predecessor period, the Company applied Financial Accounting Standards Board Codification ("FASC") Topic 852, *Reorganizations,* in preparing the consolidated financial statements. FASC Topic 852 requires the financial statements, for periods subsequent to the commencement of the Chapter 11 Restructuring, to distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain charges incurred during 2020 related to the Chapter 11 Restructuring, including the write-off of unamortized long-term debt fees and discounts associated with debt classified as liabilities subject to compromise, and professional fees incurred directly as a result of the Chapter 11 Restructuring are recorded as "Reorganization items, net" in our Consolidated Statements of Operations in the Predecessor period. FASC Topic 852 requires certain additional reporting for financial statements prepared between the bankruptcy filing date and the date of emergence from bankruptcy, including:

- Reclassification of pre-petition liabilities that are unsecured, under-secured or where it cannot be determined that the liabilities are fully secured, to a separate line item in the Unaudited Condensed Consolidated Balance Sheet titled "Liabilities subject to compromise"; and
- Segregation of Reorganization items, net as a separate line in the Unaudited Condensed Consolidated Statements of Operations.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern and contemplate the realization of assets and the satisfaction of liabilities in the normal course of business. During the Chapter 11 Restructuring, the Company's ability to continue as a going concern was contingent upon the Company's ability to successfully implement a prepackaged joint plan of reorganization, among other factors. As a result of the effectiveness and implementation of the restructuring, there is no longer substantial doubt about the Company's ability to continue as a going concern.

Principles of Reporting and Consolidation

The consolidated financial statements herein have been prepared in accordance with GAAP and include the accounts of Denbury and entities in which we hold a controlling financial interest. Undivided interests in oil and gas joint ventures are consolidated on a proportionate basis. All intercompany balances and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amount of certain assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during each reporting period. Management believes its estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates underlying these financial statements include (1) the fair value of financial derivative instruments; (2) the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties, the related present value of estimated future net cash flows therefrom and the ceiling test; (3) future net cash flow estimates used in the impairment assessment of long-lived assets; (4) the estimated quantities of proved and probable CO_2 reserves used to compute depletion of CO_2 properties; (5) estimated useful lives used to compute depreciation and amortization of long-lived assets; (6) accruals related to oil and natural gas sales volumes and revenues, capital expenditures and lease operating expenses; (7) the estimated costs and timing of future asset retirement obligations; (8) estimates made in the calculation of income taxes; and (9) fair value estimates including estimates of reorganization value, enterprise value, and the fair value of assets and liabilities recorded as a result of the adoption of fresh start accounting. While management is not aware of any significant revisions to any of its current year-end estimates, there will likely be future revisions to its estimates resulting from matters such as revisions in estimated oil and natural gas volumes, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and natural gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period in which the adjustment occurs.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current year presentation. Such reclassifications had no impact on our reported total revenues, expenses, net income, current assets, total assets, current liabilities, total liabilities or stockholders' equity.

Cash, Cash Equivalents, and Restricted Cash

We consider all highly liquid investments to be cash equivalents if they have maturities of three months or less at the date of purchase. The following table provides a reconciliation of cash, cash equivalents, and restricted cash as reported within the Consolidated Balance Sheets to "Cash, cash equivalents, and restricted cash at end of period" as reported within the Consolidated Statements of Cash Flows:

	Successor	Predecessor
In thousands	December 31, 2020	December 31, 2019
Cash and cash equivalents	$ 518	$ 516
Restricted cash, current	1,000	—
Restricted cash included in other assets	40,730	32,529
Total cash, cash equivalents, and restricted cash shown in the Consolidated Statements of Cash Flows	$ 42,248	$ 33,045

Restricted cash, current in the table above represents restricted escrow funds related to a deposit for our Wyoming working interest acquisition (see Note 17, *Subsequent Event*) and our December 2020 sale of non-producing surface acreage in the Houston area. Other restricted cash amounts represent escrow accounts that are legally restricted for certain of our asset retirement obligations, and are included in "Other assets" in the accompanying Consolidated Balance Sheets.

Oil and Natural Gas Properties

Capitalized Costs. We follow the full cost method of accounting for oil and natural gas properties. Under this method, all costs related to the acquisition, exploration and development of oil and natural gas reserves are capitalized and accumulated in a single cost center representing our activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and nonproductive wells, capitalized interest on qualifying projects, and general and administrative expenses directly related to exploration and development activities, and do not include any costs related to production, general corporate overhead or similar activities. We assign the purchase price of oil and natural gas properties we acquire to proved and unevaluated properties based on the estimated fair values as defined in the FASC *Fair Value Measurement* topic. Proceeds received from disposals are credited against accumulated costs except when the sale represents a significant disposal of reserves, in which case a gain or loss would be recognized. A disposal of 25% or more of our proved reserves would be considered significant.

Depletion and Depreciation. The costs capitalized, including production equipment and future development costs, are depleted or depreciated using the unit-of-production method, based on proved oil and natural gas reserves as determined by independent petroleum engineers. Oil and natural gas reserves are converted to equivalent units on a basis of 6,000 cubic feet of natural gas to one barrel of crude oil.

Under full cost accounting, we may exclude certain unevaluated costs from the amortization base pending determination of whether proved reserves can be assigned to such properties. The costs classified as unevaluated are transferred to the full cost amortization base as the properties are developed, tested and evaluated. At least annually, we test these assets for impairment based on an evaluation of management's expectations of future pricing, evaluation of lease expiration terms, and planned project development activities. As a result of this analysis, we recognized impairments of our unevaluated costs totaling $18.2 million during the year ended December 31, 2019, whereby these costs were transferred to the full cost amortization base. Given the significant declines in NYMEX oil prices in March and April 2020 due to the oil supply and demand imbalance precipitated by the dramatic fall in demand associated with the COVID-19 coronavirus ("COVID-19") pandemic combined with the concurrent OPEC+ decision to increase oil supply, we reassessed our development plans and transferred $244.9 million of our unevaluated costs to the full cost pool during the Predecessor period from January 1, 2020 through September 18, 2020. Upon emergence from bankruptcy, the Company adopted fresh start accounting which resulted in our oil and natural gas properties, including unevaluated properties, being recorded at their fair values at the Emergence Date (see Note 2, *Fresh Start Accounting*, for additional information).

Write-Down of Oil and Natural Gas Properties. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as (1) the present value of estimated future net revenues from proved oil and natural gas reserves before future abandonment costs (discounted at 10%), based on the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period prior to the end of a particular reporting period; plus (2) the cost of properties not being amortized; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) related income tax effects. Our future net revenues from proved oil and natural gas reserves are not reduced for development costs related to the cost of drilling for and developing CO_2 reserves nor those related to the cost of constructing CO_2 pipelines, as we do not have to incur additional costs to develop the proved oil and natural gas reserves. Therefore, we include in the ceiling test, as a reduction of future net revenues, that portion of our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves. The fair value of our oil and natural gas derivative contracts is not included in the ceiling test, as we do not designate these contracts as hedge instruments for accounting purposes. The cost center ceiling test is prepared quarterly.

The average first-day-of-the-month NYMEX oil price used in estimating our proved reserves, after adjustments for market differentials and transportation expenses by field, was $55.55 at December 31, 2019, $40.08 at September 18, 2020, and $35.84 at December 31, 2020. Primarily as a result of these commodity price declines, the Predecessor recognized full cost pool ceiling test write-downs of $996.7 million during the period from January 1, 2020 through September 18, 2020, and an additional full cost pool ceiling test write-down of $1.0 million was recognized during the Successor period from September 19, 2020 through December 31, 2020. We did not record any ceiling test write-downs during the Predecessor periods of 2018 or 2019.

Joint Interest Operations. Substantially all of our oil and natural gas exploration and production activities are conducted jointly with others. These financial statements reflect only our proportionate interest in such activities, and any amounts due from other partners are included in trade receivables.

Tertiary Injection Costs. Our tertiary operations are conducted in reservoirs that have already produced significant amounts of oil over many years; however, in accordance with the Securities and Exchange Commission ("SEC") rules and regulations for recording proved reserves, we cannot recognize proved reserves associated with enhanced recovery techniques, such as CO_2 injection, until we can demonstrate production resulting from the tertiary process or unless the field is analogous to an existing flood.

We capitalize, as a development cost, injection costs in fields that are in their development stage, which means we have not yet seen incremental oil production due to the CO_2 injections (i.e., a production response). These capitalized development costs are included in our unevaluated property costs until we are able to recognize proved reserves associated with the development project. After we see a production response to the CO_2 injections (i.e., the production stage), injection costs are expensed as incurred, and any previously deferred unevaluated development costs become subject to depletion.

CO_2 Properties

We own and produce CO_2 reserves, a non-hydrocarbon resource, that are used in our tertiary oil recovery operations on our own behalf and on behalf of other interest owners in enhanced recovery fields, with a portion sold to third-party industrial users. We record revenue from our sales of CO_2 to third parties when it is produced and sold. Expenses related to the production of CO_2 are allocated between volumes sold to third parties and volumes consumed internally that are directly related to our tertiary production. The expenses related to third-party sales are recorded in "CO_2 operating and discovery expenses," and the expenses related to internal use are recorded in "Lease operating expenses" in the Consolidated Statements of Operations or are capitalized as oil and natural gas properties in our Consolidated Balance Sheets, depending on the stage of the tertiary flood that is receiving the CO_2 (see *Tertiary Injection Costs* above for further discussion).

Costs incurred to search for CO_2 are expensed as incurred until proved or probable reserves are established. Once proved or probable reserves are established, costs incurred to obtain those reserves are capitalized and classified as "CO_2 properties" on our Consolidated Balance Sheets. Capitalized CO_2 costs are aggregated by geologic formation and depleted on a unit-of-production basis over proved and probable reserves.

Pipelines

CO_2 used in our tertiary floods is transported to our fields through CO_2 pipelines. Costs of CO_2 pipelines under construction are not depreciated until the pipelines are placed into service. Pipelines are depreciated on a straight-line basis over their estimated useful lives, which range from 20 to 43 years. Capitalized costs include $0.7 million of CO_2 pipelines as of December 31, 2020, that were either under construction or had not been placed into service and therefore, were not subject to depreciation during 2020.

Property and Equipment – Other

Other property and equipment, which includes furniture and fixtures, vehicles, and computer equipment and software, is depreciated principally on a straight-line basis over each asset's estimated useful life. Vehicles and furniture and fixtures are generally depreciated over a useful life of one to six years, and computer equipment and software are generally depreciated over a useful life of one to five years. Leasehold improvements are amortized over the shorter of the estimated useful life or the remaining lease term.

Maintenance and repair costs that do not extend the useful life of the property or equipment are charged to expense as incurred.

Intangible Assets

Our intangible assets subject to amortization for the Predecessor period primarily consisted of amounts assigned in purchase accounting to a CO_2 purchase contract with ConocoPhillips to offtake CO_2 from the Lost Cabin gas plant in Wyoming, and for the Successor period represent amounts assigned in fresh start accounting to long-term contracts to sell CO_2 to industrial customers. We amortize the CO_2 contract intangible assets on a straight-line basis over their estimated useful lives, which range from seven to 14 years. Total amortization expense for our intangible assets was $2.7 million during the Successor period September 19, 2020 through December 31, 2020, $1.7 million for the Predecessor period January 1, 2020 through September 18, 2020, and $2.4 million and $2.4 million during the years ended 2019 and 2018, respectively. The following table summarizes the carrying value of our intangible assets as of December 31, 2020 and 2019:

	Successor	Predecessor
In thousands	December 31, 2020	December 31, 2019
Long-term contracts to sell CO_2 to industrial customers	$ 97,943	$ —
Other intangibles	2,167	37,668
Accumulated amortization	(2,748)	(15,529)
Net book value	$ 97,362	$ 22,139

As of December 31, 2020, our estimated amortization expense for our intangible assets subject to amortization over the next five years is as follows:

In thousands	
2021	$ 9,117
2022	9,117
2023	9,117
2024	9,117
2025	9,117

Impairment Assessment of Long-Lived Assets

We test long-lived assets for impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. These long-lived assets, which are not subject to our full cost pool ceiling test, are principally comprised of our capitalized CO_2 properties and pipelines, and for the Successor period also included long-term contracts to sell CO_2 to industrial customers. Given the significant declines in NYMEX oil prices to approximately $20 per Bbl in late March 2020 due to OPEC supply pressures and a reduction in worldwide oil demand amid the COVID-19 pandemic, we performed a long-lived asset impairment test for our two long-lived asset groups (Gulf Coast region and Rocky Mountain region) as of March 31, 2020 (Predecessor).

We perform our long-lived asset impairment test by comparing the net carrying costs of our long-lived asset groups to the respective expected future undiscounted net cash flows that are supported by these long-lived assets which include production of our probable and possible oil and natural gas reserves. The portion of our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves is included in the full cost pool ceiling test as a reduction to future net revenues. The remaining net capitalized costs that are not included in the full cost pool ceiling test, and related intangible assets, are subject to long-lived asset impairment testing. These costs totaled approximately $1.3 billion as of March 31, 2020 (Predecessor). If the undiscounted net cash flows are below the net carrying costs for an asset group, we must record an impairment loss by the amount, if any, that net carrying costs exceed the fair value of the long-lived asset group. The undiscounted net cash flows for our asset groups exceeded the net carrying costs; thus, step two of the impairment test was not required and no impairment was recorded.

Significant assumptions impacting expected future undiscounted net cash flows include projections of future oil and natural gas prices, projections of estimated quantities of oil and natural gas reserves, projections of future rates of production, timing and amount of future development and operating costs, projected availability and cost of CO_2, projected recovery factors of tertiary reserves and risk-adjustment factors applied to the cash flows. We performed a qualitative assessment as of June 30, 2020 and September 18, 2020 (Predecessor periods) and determined there were no material changes to our key cash flow assumptions and no triggering events since the analysis performed as of March 31, 2020; therefore, no impairment test was performed for the second quarter of 2020 or for the period ending September 18, 2020. Upon emergence from bankruptcy, the Company adopted fresh start accounting which resulted in our long-lived assets being recorded at their fair value at the Emergence Date (see Note 2, *Fresh Start Accounting*, for additional information). We performed a qualitative assessment as of December 31, 2020 (Successor period) and determined there were no material changes to our key cash flow assumptions and no triggering events since the Company's assets were revalued in fresh start accounting, September 18, 2020; therefore, no impairment test was performed for the fourth quarter of 2020.

Asset Retirement Obligations

In general, our future asset retirement obligations relate to future costs associated with plugging and abandoning our oil, natural gas and CO_2 wells, removing equipment and facilities from leased acreage, and returning land to its original condition. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using our credit-adjusted-risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset. Revisions to estimated retirement obligations will result in an adjustment to the related capitalized asset and corresponding liability. If the liability for an oil or natural gas well is settled for an amount other than the recorded amount, the difference is recorded to the full cost pool.

Asset retirement obligations are estimated at the present value of expected future net cash flows. We utilize unobservable inputs in the estimation of asset retirement obligations that include, but are not limited to, costs of labor and materials, profits on costs of labor and materials, the effect of inflation on estimated costs, and the discount rate. Accordingly, asset retirement obligations are considered a Level 3 measurement under the FASC *Fair Value Measurement* topic.

Commodity Derivative Contracts

We utilize oil and natural gas derivative contracts to mitigate our exposure to commodity price risk associated with our future oil and natural gas production. These derivative contracts have historically consisted of options, in the form of price floors, collars, three-way collars, fixed-price swaps, fixed-price swaps enhanced with a sold put, and basis swaps. Our derivative financial instruments, other than any derivative instruments that are designated under the "normal purchase normal sale" exclusion, are recorded on the balance sheet as either an asset or a liability measured at fair value. We do not apply hedge accounting to our commodity derivative contracts; accordingly, changes in the fair value of these instruments are recognized in "Commodity derivatives expense (income)" in our Consolidated Statements of Operations in the period of change.

Concentrations of Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents, trade and accrued production receivables, and the derivative instruments discussed above. Our cash equivalents represent high-quality securities placed with various investment-grade institutions. This investment practice limits our exposure to concentrations of credit risk. Our trade and accrued production receivables are dispersed among various customers and purchasers; therefore, concentrations of credit risk are limited. We evaluate the credit ratings of our purchasers, and if customers are considered a credit risk, letters of credit are the primary security obtained to support lines of credit. We attempt to minimize our credit risk exposure to the counterparties of our oil and natural gas derivative contracts through formal credit policies, monitoring procedures and diversification. All of our derivative contracts are with parties that are lenders under our senior secured bank credit facility (or affiliates of such lenders). There are no margin requirements with the counterparties of our derivative contracts.

Oil and natural gas sales are made on a day-to-day basis or under short-term contracts at the current area market price. We would not expect the loss of any purchaser to have a material adverse effect upon our operations. For the Successor period September 19, 2020 through December 31, 2020, three purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (30%), Marathon Petroleum (13%) and Hunt Crude Oil Supply Company (12%), and for the Predecessor period January 1, 2020 through September 18, 2020, three purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (30%), Hunt Crude Oil Supply Company (12%) and Marathon Petroleum (12%). For the year ended December 31, 2019 (Predecessor), three purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (32%), Hunt Crude Oil Supply Company (11%) and Sunoco Inc. (11%). For the year ended December 31, 2018 (Predecessor), two purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (24%) and Hunt Crude Oil Supply Company (10%).

Other Receivables

During 2018, we recorded a $16.9 million impairment of a loan related to a proposed plant in the Gulf Coast that would potentially supply CO_2 to Denbury, due to uncertainties of the project achieving financial close. The impairment was included within "Other expenses" in our Consolidated Statements of Operations for the year ended December 31, 2018.

Income Taxes

Income taxes are accounted for using the asset and liability method, under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at year end. 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 recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement.

Net Income (Loss) per Common Share

Basic net income (loss) per common share is computed by dividing the net income (loss) attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income (loss) per common share is calculated in the same manner, but includes the impact of potentially dilutive securities. Potentially dilutive securities during the Successor period consist of nonvested restricted stock units, nonvested performance stock units, and warrants, and during the Predecessor period have historically consisted of nonvested restricted stock, nonvested performance-based equity awards, and shares into which our convertible senior notes are convertible.

The following table sets forth the reconciliations of net income (loss) and weighted average shares used for purposes of calculating basic and diluted net income (loss) per common share for the periods indicated:

	Successor	Predecessor		
	Period from Sept. 19, 2020 through	Period from Jan. 1, 2020 through	Year Ended December 31,	
In thousands	Dec. 31, 2020	Sept. 18, 2020	2019	2018
Numerator				
Net income (loss) – basic	$ (50,658)	$ (1,432,578)	$ 216,959	$ 322,698
Effect of potentially dilutive securities				
Interest on convertible senior notes including amortization of discount, net of tax	—	—	14,134	539
Net income (loss) – diluted	$ (50,658)	$ (1,432,578)	$ 231,093	$ 323,237
Denominator				
Weighted average common shares outstanding – basic	50,000	495,560	459,524	432,483
Effect of potentially dilutive securities				
Restricted stock and performance-based equity awards	—	—	2,396	6,500
Convertible senior notes(1)	—	—	48,421	17,186
Weighted average common shares outstanding – diluted	50,000	495,560	510,341	456,169

(1) For the year ended December 31, 2019, shares shown under "convertible senior notes" represent the prorated portion of the approximately 90.9 million shares of the Predecessor's common stock issuable upon full conversion of the convertible senior notes which were issued on June 19, 2019 (see Note 8, *Long-Term Debt – 2019 Predecessor Debt Reduction Transactions*).

Time-vesting restricted stock is included in basic weighted average common shares from the vesting date (although time-vesting restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares for the years ended December 31, 2019 and 2018, the nonvested restricted stock and performance-based equity awards are included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, and for the shares underlying the convertible senior notes as if the convertible senior notes were converted at the earliest date outstanding during the respective periods. In April and May 2018, all of the then outstanding 3½% Convertible Senior Notes due 2024 and 5% Convertible Senior Notes due 2023 converted into shares of Denbury common stock, resulting in the issuance of 55.2 million shares of our common stock upon conversion. These shares have been included in basic weighted average common shares outstanding beginning on the date of conversion.

The following securities could potentially dilute earnings per share in the future, but were excluded from the computation of diluted net income (loss) per share, as their effect would have been antidilutive:

	Successor	Predecessor		
	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	Year Ended December 31,	
In thousands			2019	2018
Stock appreciation rights	—	1,007	2,027	2,743
Restricted stock and performance-based equity awards	—	7,280	5,505	1,234
Convertible senior notes	—	87,888	—	—
Restricted stock units(1)	328	—	—	—
Warrants(2)	5,526	—	—	—

(1) Shares represent the impact over the Successor period of the approximately 1.2 million shares of the Successor's common stock issuable upon full vesting of the restricted stock unit awards issued on December 4, 2020 pursuant to the 2020 Omnibus Stock and Incentive Plan (see Note 11, *Stock Compensation*).

(2) Shares represent the impact over the Successor period of the approximately 5.5 million shares of the Successor's common stock issuable upon full exercise of the series A warrants, at an exercise price of $32.59 per share, and series B warrants, at an exercise price of $35.41 per share, which were issued pursuant to the Plan to the Predecessor's convertible senior notes, senior subordinated notes, and equity holders. The dilution from exercise of the series A or series B warrants could be reduced to the extent warrants are exercised on a cashless basis.

Environmental and Litigation Contingencies

The Company makes judgments and estimates in recording liabilities for contingencies such as environmental remediation or ongoing litigation. Liabilities are recorded when it is both probable that a loss has been incurred and such loss is reasonably estimable. Assessments of liabilities are based on information obtained from independent and in-house experts, loss experience in similar situations, actual costs incurred, and other case-by-case factors. Any related insurance recoveries are recognized in our financial statements during the period received or at the time receipt is determined to be virtually certain.

Recent Accounting Pronouncements

Recently Adopted

Financial Instruments – Credit Losses. In June 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-13, *Financial Instruments – Credit Losses* ("ASU 2016-13"). ASU 2016-13 changes the impairment model for most financial assets and certain other instruments, including trade and other receivables, and requires the use of a new forward-looking expected loss model that will result in the earlier recognition of allowances for losses. Effective January 1, 2020, we adopted ASU 2016-13. The implementation of this standard did not have a material impact on our consolidated financial statements.

Fair Value Measurement. In August 2018, the FASB issued ASU 2018-13, *Fair Value Measurement (Topic 820) – Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurements* ("ASU 2018-13"). ASU 2018-13 adds, modifies, or removes certain disclosure requirements for recurring and nonrecurring fair value measurements based on the FASB's consideration of costs and benefits. Effective January 1, 2020, we adopted ASU 2018-13. The implementation of this standard did not have a material impact on our consolidated financial statements or footnote disclosures.

Leases. During the Predecessor period, effective January 1, 2019, we adopted FASB ASU 2016-02, *Leases*, and ASU 2018-01, *Leases (Topic 842) – Land Easement Practical Expedient for Transition to Topic 842*, using the modified retrospective method with an application date of January 1, 2019. For a discussion of our current accounting for lease contracts, see Note 5, *Leases*.

Not Yet Adopted

Reference Rate Reform. In March 2020, the FASB issued ASU 2020-04, *Reference Rate Reform (Topic 848)* ("ASU 2020-04"). ASU 2020-04 provides optional expedients and exceptions for applying GAAP to contracts, hedging relationships, and other transactions to ease financial reporting burdens related to the expected market transition from the London Interbank Offered Rate ("LIBOR") or another reference rate to alternative reference rates. The amendments in this ASU were effective upon issuance and generally can be applied to applicable contract modifications through December 31, 2022. Currently, our Successor Bank Credit Agreement is our only contract that makes reference to a LIBOR rate and the agreement outlines the specific procedures that will be undertaken once an appropriate alternative benchmark is identified. We do not expect this guidance to have a significant impact on our consolidated financial statements and related footnote disclosures.

Income Taxes. In December 2019, the FASB issued ASU 2019-12, *Income Taxes (Topic 740) – Simplifying the Accounting for Income Taxes* ("ASU 2019-12"). The objective of ASU 2019-12 is to simplify the accounting for income taxes by removing certain exceptions to the general principles in Topic 740 and to provide more consistent application to improve the comparability of financial statements. The amendments in this ASU are effective for fiscal years beginning after December 15, 2020, and early adoption is permitted. We do not expect the adoption of this guidance to have a significant impact on our consolidated financial statements and related footnote disclosures.

Note 2. Fresh Start Accounting

Fresh Start Accounting

Upon emergence from bankruptcy, we met the criteria and were required to adopt fresh start accounting in accordance with FASC Topic 852, *Reorganizations*, which on the Emergence Date resulted in a new entity, the Successor, for financial reporting purposes, with no beginning retained earnings or deficit as of the fresh start reporting date. The criteria requiring fresh start accounting are: (1) the holders of the then-existing common shares of the Predecessor received less than 50 percent of the new common shares of the Successor outstanding upon emergence from bankruptcy and (2) the reorganization value of the Company's assets immediately prior to confirmation of the Plan was less than the total of all post-petition liabilities and allowed claims.

Fresh start accounting requires that new fair values be established for the Company's assets, liabilities and equity as of the date of emergence from bankruptcy, September 18, 2020, and therefore certain values and operational results of the consolidated financial statements subsequent to September 18, 2020 are not comparable to those in the Company's consolidated financial statements prior to, and including September 18, 2020. The Emergence Date fair values of the Successor's assets and liabilities differ materially from their recorded values as reflected on the historical balance sheet of the Predecessor.

Reorganization Value

The reorganization value derived from the range of enterprise values associated with the Plan was allocated to the Company's identifiable tangible and intangible assets and liabilities based on their fair values. Under FASC Topic 852, reorganization value generally approximates the fair value of the entity before considering liabilities and is intended to approximate the amount a willing buyer would pay for the assets immediately after the effects of the restructuring. The value of the reconstituted entity (i.e., Successor) was based on management projections and the valuation models as determined by the Company's financial advisors in setting an estimated range of enterprise values. As set forth in the Plan and Disclosure Statement approved by the Bankruptcy Court, the valuation analysis resulted in an enterprise value between \$1.1 billion and \$1.5 billion, with a midpoint of \$1.3 billion. For U.S. GAAP purposes, we valued the Successor's individual assets, liabilities, and equity instruments and determined the value of the enterprise was approximately \$1.3 billion as of the Emergence Date, which fell in line with the midpoint of the forecast enterprise value ranges approved by the Bankruptcy Court. Specific valuation approaches and key assumptions used to arrive at reorganization value, and the value of discrete assets and liabilities resulting from the application of fresh start accounting, are described below in greater detail within the valuation process.

The following table reconciles the enterprise value to the equity value of the Successor as of the Emergence Date:

In thousands	Sept. 18, 2020
Enterprise value	$ 1,280,856
Plus: Cash and cash equivalents	45,585
Less: Total debt	(231,022)
Equity value	$ 1,095,419

The following table reconciles enterprise value to reorganization value of the Successor (i.e., value of the reconstituted entity) and total reorganization value:

In thousands	Sept. 18, 2020
Enterprise value	$ 1,280,856
Plus: Cash and cash equivalents	45,585
Plus: Current liabilities excluding current maturities of long-term debt	239,738
Plus: Non-interest-bearing noncurrent liabilities	185,228
Reorganization value of the reconstituted Successor	$ 1,751,407

With the assistance of third-party valuation advisors, we determined the enterprise and corresponding equity value of the Successor using various valuation approaches and methods, including: (i) income approach using a calculation of the present value of future cash flows based on our financial projections, (ii) the market approach using selling prices of similar assets and (iii) the cost approach.

The enterprise value and corresponding equity value are dependent upon achieving the future financial results set forth in our valuation using an asset-based methodology of estimated proved reserves, undeveloped properties, and other financial information, considerations and projections, applying a combination of the income, cost and market approaches as of the fresh start reporting date of September 18, 2020. All estimates, assumptions, valuations and financial projections, including the fair value adjustments, the financial projections, the enterprise value and equity value projections, are inherently subject to significant uncertainties and the resolution of contingencies beyond our control. Accordingly, there is no assurance that the estimates, assumptions, valuations or financial projections will be realized, and actual results could vary materially.

Reorganization Items, Net

Reorganization items represent (i) expenses incurred during the Chapter 11 Restructuring subsequent to the Petition Date as a direct result of the Plan, (ii) gains or losses from liabilities settled and (iii) fresh start accounting adjustments and are recorded in “Reorganization items, net” in our Consolidated Statements of Operations. Professional service provider charges associated with our restructuring that were incurred before the Petition Date and after the Emergence Date are recorded in “Other expenses” in our Consolidated Statements of Operations. Contractual interest expense of $22.0 million from the Petition Date through the Emergence Date associated with our outstanding senior secured second lien notes, convertible senior notes, and senior subordinated notes was not accrued or recorded in the consolidated statement of operations as interest expense.

The following table summarizes the losses (gains) on reorganization items, net:

In thousands	Predecessor Period from Jan. 1, 2020 through Sept. 18, 2020
Gain on settlement of liabilities subject to compromise	$ (1,024,864)
Fresh start accounting adjustments	1,834,423
Professional service provider fees and other expenses	11,267
Success fees for professional service providers	9,700
Loss on rejected contracts and leases	10,989
Valuation adjustments to debt classified as subject to compromise	757
DIP credit agreement fees	3,107
Acceleration of Predecessor stock compensation expense	4,601
Total reorganization items, net	$ 849,980

Payments of professional service provider fees and success fees of $12.7 million and fees of $3.1 million related to the Senior Secured Superpriority Debtor-in-Possession Credit Agreement (“DIP Facility”) were included in cash outflows from operating activities and financing activities, respectively, in our Consolidated Statements of Cash Flows for the period January 1, 2020 through September 18, 2020.

Valuation Process

The fair values of our principal assets, including oil and natural gas properties, CO_2 properties, pipelines, other property and equipment, long-term contracts to sell CO_2 to industrial customers, favorable and unfavorable vendor contracts, pipeline financing liabilities and right-of-use assets, asset retirement obligations and warrants were estimated as of the Emergence Date.

Oil and Natural Gas Properties

The Company’s principal assets are its oil and natural gas properties, which are accounted for under the full cost accounting method as described in Note 1, *Nature of Operations and Summary of Significant Accounting Policies – Oil and Natural Gas Properties*. The Company determined the fair value of its oil and gas properties based on the discounted cash flows expected to be generated from these assets. The computations were based on market conditions and reserves in place as of the Emergence Date.

The fair value analysis was based on the Company’s estimated future production rates of proved and probable reserves as prepared by the Company’s independent petroleum engineers. Discounted cash flow models were prepared using the estimated future revenues and operating costs for all developed wells and undeveloped properties comprising the proved and probable reserves. Future revenues were based upon future production rates and forward strip oil and natural gas prices as of the Emergence Date through 2024 and escalated for inflation thereafter, adjusted for differentials. Operating costs were adjusted for inflation beginning in year 2025. A risk adjustment factor was applied to each reserve category, consistent with the risk of the category. The discounted cash flow models also included adjustments for income tax expenses.

Discount factors utilized were derived using a weighted average cost of capital computation, which included an estimated cost of debt and equity for market participants with similar geographies and asset development type and varying corporate income tax rates based on the expected point of sale for each property’s produced assets. Reserve values were also adjusted for any asset retirement obligations as well as for CO_2 indirect costs not directly allocable to oil fields. Based on this analysis, the Company concluded the fair value of its proved and probable reserves was $865.4 million as of the Emergence Date (see footnote 10 to *Fresh Start Adjustments* discussion below).

CO_2 Properties

The fair value of CO_2 properties includes the value of CO_2 mineral rights and associated infrastructure and was determined using the discounted cash flow method under the income approach. After-tax cash flows were forecast based on expected costs to produce and transport CO_2 as provided by management, and income was imputed using a gross-up of costs based on a five-year average historical EBITDA margin for publicly traded companies that primarily develop or produce natural gas. Cash flows were also adjusted for a market participant profit on CO_2 costs, since Denbury charges oil fields for CO_2 use on a cost basis. Cash flows were then discounted using a rate considering reduced risk associated with CO_2 industrial sales.

Pipelines

The fair values of our pipelines were determined using a combination of the replacement cost method under the cost approach and the discounted cash flow method under the income approach. The replacement cost method considers historical acquisition costs for the assets adjusted for inflation, as well as factors in any potential obsolescence based on the current condition of the assets and the ability of those assets to generate cash flow. For assets valued using the discounted cash flow method, after-tax cash flows were forecast based on expected costs provided by management, and profits were imputed using a gross-up of costs based on a five-year average historical EBITDA margin for publicly traded companies that primarily transport natural gas. Pipeline depreciable lives represent the remaining estimated useful lives of the pipelines, which will be depreciated on a straight-line basis ranging from 20 to 43 years.

Other Property and Equipment

The fair value of the non-reserve related property and equipment such as land, buildings, equipment, leasehold improvements and software was determined using the replacement cost method under the cost approach which considers historical acquisition costs for the assets adjusted for inflation, as well as factors in any potential obsolescence based on the current condition of the assets and the ability of those assets to generate cash flow.

Long-Term Contracts to Sell CO_2 to Industrial Customers

The fair value of long-term contracts to sell CO_2 to industrial customers was determined using the multi-period excess earnings method ("MPEEM") under the income approach. MPEEM attributes cash flow to a specific intangible asset based on residual cash flows from a set of assets generating revenues after accounting for appropriate returns on and of other assets contributing to that revenue generation. Cash flows were forecast based on expected changes in pricing, volumes, renewal rates, and costs using volumes and prices through and beyond the initial contract terms. After-tax cash flows were discounted using a rate considering reduced risk of these industrial contracts relative to overall oil and gas production risks. The contracts will be depreciated over a useful life of seven to 14 years.

Favorable and Unfavorable Vendor Contracts

We recognized both favorable and unfavorable contracts using the incremental value method under the income approach. The incremental value method calculates value on the basis of the pricing differential between historical contracted rates and estimated pricing that the Company would most likely receive if it entered into similar contract conditions (other than the price) as of the Emergence Date. The differential is applied to expected contract volumes, tax-affected and discounted at a discount rate consistent with the risk of the associated cash flows.

Asset Retirement Obligations

The fair value of the asset retirement obligations was revalued based upon estimated current reclamation costs for our assets with reclamation obligations, an appropriate long-term inflation adjustment, and our revised credit adjusted risk-free rate ("CARFR"). The new CARFR was based on an evaluation of similar industry peers with similar factors such as emergence, new capital structure and current rates for oil and gas companies.

Pipeline Financing Liabilities

The fair value of the pipeline financing liabilities was measured as the present value of the remaining payments under the restructured pipeline agreements (see Note 8, *Long-Term Debt – Restructuring of Pipeline Financing Transactions*, for further discussion).

Warrants

The fair values of the warrants issued upon the Emergence Date were estimated by applying a Black-Scholes-Merton model. The Black-Scholes-Merton model is a pricing model used to estimate the fair value of a European-style call or put option/warrant based on a current stock price, strike price, time to maturity, risk-free rate, annual volatility rate, and annual dividend yield.

The model used the following assumptions: implied stock price (total equity divided by total shares outstanding) of the Successor's shares of common stock of $22.14; exercise price per share of $32.59 and $35.41 for series A and B warrants, respectively; expected volatility of 49.3% and 53.6% for series A and B warrants, respectively; risk-free interest rates of 0.3% and 0.2% for series A and B warrants, respectively, using the United States Treasury Constant Maturity rates; and an expected annual dividend yield of 0%. Expected volatility was estimated using volatilities of similar entities whose share or option prices and assumptions were publicly available. The time to maturity of the warrants was based on the contractual terms of the warrants of five and three years for series A and series B warrants, respectively. The values were also adjusted for potential dilution impacts.

Condensed Consolidated Balance Sheet

The following illustrates the effects on the Company's consolidated balance sheet due to the reorganization and fresh start accounting adjustments. The explanatory notes following the table below provide further details on the adjustments, including the assumptions and methods used to determine fair value for its assets, liabilities, and warrants.

	As of September 18, 2020			
In thousands	Predecessor	Reorganization Adjustments	Fresh Start Adjustments	Successor
Assets				
Current assets				
Cash and cash equivalents	$ 73,372	$ (27,787) (1)	$ —	$ 45,585
Restricted cash	—	10,662 (2)	—	10,662
Accrued production receivable	112,832	—	—	112,832
Trade and other receivables, net	36,221	—	—	36,221
Derivative assets	32,635	—	—	32,635
Other current assets	12,968	(539) (3)	—	12,429
Total current assets	268,028	(17,664)	—	250,364
Property and equipment				
Oil and natural gas properties (using full cost accounting)				
Proved properties	11,723,546	—	(10,941,313)	782,233
Unevaluated properties	650,553	—	(538,570)	111,983
CO_2 properties	1,198,515	—	(1,011,169)	187,346
Pipelines	2,339,864	—	(2,207,246)	132,618
Other property and equipment	201,565	—	(104,152)	97,413
Less accumulated depletion, depreciation, amortization and impairment	(12,864,141)	—	12,864,141	—
Net property and equipment	3,249,902	—	(1,938,309) (10)	1,311,593
Operating lease right-of-use assets	1,774	—	69 (10)	1,843
Derivative assets	501	—	—	501
Intangible assets, net	20,405	—	79,678 (11)	100,083
Other assets	81,809	8,241 (4)	(3,027) (12)	87,023
Total assets	$ 3,622,419	$ (9,423)	$ (1,861,589)	$ 1,751,407

In thousands	As of September 18, 2020 Predecessor	Reorganization Adjustments		Fresh Start Adjustments		Successor
Liabilities and Stockholders' Equity						
Current liabilities						
Accounts payable and accrued liabilities	$ 67,789	$ 102,793	(5)	$ 3,738	(13)	$ 174,320
Oil and gas production payable	39,372	16,705	(6)	—		56,077
Derivative liabilities	8,613	—		—		8,613
Current maturities of long-term debt	—	73,199	(6)	364	(14)	73,563
Operating lease liabilities	—	757	(6)	(29)	(10)	728
Total current liabilities	115,774	193,454		4,073		313,301
Long-term liabilities						
Long-term debt, net of current portion	140,000	42,610	(6)	(25,151)	(14)	157,459
Asset retirement obligations	2,727	180,408	(6)	(24,697)	(10)	158,438
Derivative liabilities	295	—		—		295
Deferred tax liabilities, net	—	417,951	(6)(15)	(414,120)	(15)	3,831
Operating lease liabilities	—	515	(6)	10	(10)	525
Other liabilities	—	3,540	(6)	18,599	(16)	22,139
Total long-term liabilities not subject to compromise	143,022	645,024		(445,359)		342,687
Liabilities subject to compromise	2,823,506	(2,823,506)	(6)	—		—
Commitments and contingencies (Note 14)						
Stockholders' equity						
Predecessor preferred stock	—	—		—		—
Predecessor common stock	510	(510)	(7)	—		—
Predecessor paid-in capital in excess of par	2,764,915	(2,764,915)	(7)	—		—
Predecessor treasury stock, at cost	(6,202)	6,202	(7)	—		—
Successor preferred stock	—	—		—		—
Successor common stock	—	50	(8)	—		50
Successor paid-in capital in excess of par	—	1,095,369	(8)	—		1,095,369
Accumulated deficit	(2,219,106)	3,639,409	(9)	(1,420,303)	(17)	—
Total stockholders' equity	540,117	1,975,605		(1,420,303)		1,095,419
Total liabilities and stockholders' equity	$ 3,622,419	$ (9,423)		$ (1,861,589)		$ 1,751,407

Reorganization Adjustments

(1) Represents the net cash payments that occurred on the Emergence Date as follows:

In thousands	
Sources:	
Cash proceeds from Successor Bank Credit Agreement	$ 140,000
Total cash proceeds	140,000
Uses:	
Payment in full of DIP Facility and pre-petition revolving bank credit facility	(140,000)
Retained professional service provider fees paid to escrow account	(10,662)
Non-retained professional service provider fees paid	(7,420)
Accrued interest and fees on DIP Facility	(1,464)
Debt issuance costs related to Successor Bank Credit Agreement	(8,241)
Total cash uses	(167,787)
Net uses	$ (27,787)

(2) Represents the transfer of funds to a restricted cash account utilized for the payment of fees to retained professional service providers assisting in the bankruptcy process.

(3) Represents the write-off of costs related to the DIP Facility and a run-off policy for directors' and officers' insurance coverage, partially offset by the recording of prepaid amounts for non-retained professional service provider fees.

(4) Represents debt issuance costs related to the Successor Bank Credit Agreement.

(5) Adjustments to accounts payable and accrued liabilities as follows:

In thousands	
Accrual of professional service provider fees	$ 2,826
Payment of accrued interest and fees on DIP Facility	(1,464)
Reinstatement of accounts payable and accrued liabilities from liabilities subject to compromise	101,431
Accounts payable and accrued liabilities	$ 102,793

(6) Liabilities subject to compromise were settled as follows in accordance with the Plan:

In thousands	
Liabilities subject to compromise prior to the Emergence Date:	
Settled liabilities subject to compromise	
Senior secured second lien notes	$ 1,629,457
Convertible senior notes	234,015
Senior subordinated notes	251,480
Total settled liabilities subject to compromise	2,114,952
Reinstated liabilities subject to compromise	
Current maturities of long-term debt	73,199
Accounts payable and accrued liabilities	101,431
Oil and gas production payable	16,705
Operating lease liabilities, current	757
Long-term debt, net of current portion	42,610
Asset retirement obligations	180,408
Deferred tax liabilities	289,389
Operating lease liabilities, long-term	515
Other long-term liabilities	3,540
Total reinstated liabilities subject to compromise	708,554
Total liabilities subject to compromise	2,823,506
Issuance of New Common Stock to second lien note holders	(1,014,608)
Issuance of New Common Stock to convertible note holders	(53,400)
Issuance of series A warrants to convertible note holders	(15,683)
Issuance of series B warrants to senior subordinated note holders	(6,398)
Reinstatement of liabilities subject to compromise	(708,553)
Gain on settlement of liabilities subject to compromise	$ 1,024,864

(7) Represents the cancellation of the Predecessor's common stock, treasury stock, and related components of the Predecessor's paid-in capital in excess of par. Paid-in capital in excess of par includes $4.6 million as a result of terminated Predecessor stock compensation plans.

(8) Represents the Successor's common stock and additional paid-in capital as follows:

In thousands	
Capital in excess of par value of 47,499,999 issued and outstanding shares of New Common Stock issued to holders of the senior secured second lien note claims	$ 1,014,608
Capital in excess of par value of 2,500,000 issued and outstanding shares of New Common Stock issued to holders of the convertible senior note claims	53,400
Fair value of series A warrants issued to convertible senior note holders	15,683
Fair value of series B warrants issued to senior subordinated note holders	6,398
Fair value of series B warrants issued to Predecessor equity holders	5,330
Total change in Successor common stock and additional paid-in capital	1,095,419
Less: Par value of Successor common stock	(50)
Change in Successor additional paid-in capital	$ 1,095,369

(9) Reflects the cumulative net impact of the effects on accumulated deficit as follows:

In thousands	
Cancellation of Predecessor common stock, paid-in capital in excess of par, and treasury stock	$ 2,763,824
Gain on settlement of liabilities subject to compromise	1,024,864
Acceleration of Predecessor stock compensation expense	(4,601)
Recognition of tax expenses related to reorganization adjustments	(128,556)
Professional service provider fees recognized at emergence	(9,700)
Issuance of series B warrants to Predecessor equity holders	(5,330)
Other	(1,092)
Net impact to Predecessor accumulated deficit	$ 3,639,409

Fresh Start Adjustments

(10) Reflects fair value adjustments to our (i) oil and natural gas properties, CO_2 properties, pipelines, and other property and equipment, as well as the elimination of accumulated depletion, depreciation, and amortization, (ii) operating lease right-of-use assets and liabilities, and (iii) asset retirement obligations.

(11) Reflects fair value adjustments to our long-term contracts to sell CO_2 to industrial customers.

(12) Reflects fair value adjustments to our other assets as follows:

In thousands	
Fair value adjustment for CO_2 and oil pipeline line-fill	$ (3,698)
Fair value adjustments for escrow accounts	671
Fair value adjustments to other assets	$ (3,027)

(13) Reflects fair value adjustments to accounts payable and accrued liabilities as follows:

In thousands	
Fair value adjustment for the current portion of an unfavorable vendor contract	$ 3,500
Fair value adjustment for the current portion of Predecessor asset retirement obligation	689
Write-off accrued interest on NEJD pipeline financing	(451)
Fair value adjustments to accounts payable and accrued liabilities	$ 3,738

(14) Represents adjustments to current and long-term maturities of debt associated with pipeline lease financings. The cumulative effect is as follows:

In thousands		
Fair value adjustment for Free State pipeline lease financing	$	(24,699)
Fair value adjustment for NEJD pipeline lease financing		(88)
Fair value adjustments to current and long-term maturities of debt	$	(24,787)

Our pipeline lease financings were restructured in late October 2020 (see Note 8, *Long-Term Debt – Restructuring of Pipeline Financing Transactions*).

(15) Represents (i) adjustment to deferred taxes, including the recognition of tax expenses related to reorganization adjustments as a result of the cancellation of debt and retaining tax attributes for the Successor and the reinstatement of deferred tax liabilities subject to compromise totaling $128.6 million and (ii) adjustments to deferred tax liabilities related to fresh start accounting of $414.1 million.

(16) Represents a fair value adjustment for the long-term portion of an unfavorable vendor contract.

(17) Represents the cumulative effect of the fresh start accounting adjustments discussed above.

Note 3. Predecessor Divestiture

On March 4, 2020, the Predecessor sold half of its working interest positions in four southeast Texas oil fields for $40 million net cash and a carried interest in ten wells to be drilled by the purchaser. The Predecessor did not record a gain or loss on the sale of the properties in accordance with the full cost method of accounting.

Note 4. Revenue Recognition

We record revenue in accordance with FASC Topic 606, *Revenue from Contracts with Customers*. The core principle of FASC Topic 606 is that an entity should recognize revenue for the transfer of goods or services equal to the amount of consideration that it expects to be entitled to receive for those goods or services. This principle is achieved through applying a five-step process for customer contract revenue recognition:

- Identify the contract or contracts with a customer – We derive the majority of our revenues from oil and natural gas sales contracts and CO_2 sales and transportation contracts. The contracts specify each party's rights regarding the goods or services to be transferred and contain commercial substance as they impact our financial statements. A high percentage of our receivables balance is current, and we have not historically entered into contracts with counterparties that pose a credit risk without requiring adequate economic protection to ensure collection.

- Identify the performance obligations in the contract – Each of our revenue contracts specify a volume per day, or production from a lease designated in the contract (a distinct good), to be delivered at the delivery point over the term of the contract (the identified performance obligation). The customer takes delivery and physical possession of the product at the delivery point, which generally is also the point at which title transfers and the customer obtains the risks and rewards of ownership (the identified performance obligation is satisfied).

- Determine the transaction price – Typically, our oil and natural gas contracts define the price as a formula price based on the average market price, as specified on set dates each month, for the specific commodity during the month of delivery. Certain of our CO_2 contracts define the price as a fixed contractual price adjusted to an inflation index to reflect market pricing. Given the industry practice to invoice customers the month following the month of delivery and our high probability of collection of payment, no significant financing component is included in our contracts.

- Allocate the transaction price to the performance obligations in the contract – The majority of our revenue contracts are short-term, with terms of one year or less, to which we have applied the practical expedient permitted under the standard eliminating the requirement to disclose the transaction price allocated to remaining performance obligations. In limited instances, we have revenue contracts with terms greater than one year; however, the future delivery volumes are wholly unsatisfied as they represent separate performance obligations with variable consideration. We utilized the practical expedient which eliminates the requirement to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to wholly unsatisfied performance obligations. As there is only one performance obligation associated with our contracts, no allocation of the transaction price is necessary.

- Recognize revenue when, or as, we satisfy a performance obligation – Once we have delivered the volume of commodity to the delivery point and the customer takes delivery and possession, we are entitled to payment and we invoice the customer for such delivered production. Payment under most oil and CO_2 contracts is made within a month following product delivery and for natural gas and NGL contracts is generally made within two months following delivery. Timing of revenue recognition may differ from the timing of invoicing to customers; however, as the right to consideration after delivery is unconditional based on only the passage of time before payment of the consideration is due, upon delivery we record a receivable in "Accrued production receivable" in our Consolidated Balance Sheets.

In addition to revenues from oil and natural gas sales contracts and CO_2 sales and transportation contracts, the Company enters into marketing arrangements for the purchase and sale of crude oil for third parties in the Gulf Coast region. Revenues and expenses from these transactions are presented on a gross basis, as we act as a principal in the transaction by assuming control of the commodities purchased and the responsibility to deliver the commodities sold. Revenue is recognized when control transfers to the purchaser at the delivery point based on the price received from the purchaser.

Disaggregation of Revenue

The following table summarizes our revenues by product type:

	Successor	Predecessor		
	Period from Sept. 19, 2020 through	Period from Jan. 1, 2020 through	Year Ended December 31,	
In thousands	Dec. 31, 2020	Sept. 18, 2020	2019	2018
Oil sales	$ 199,769	$ 489,251	$ 1,205,083	$ 1,412,358
Natural gas sales	1,339	2,850	6,937	10,231
CO_2 sales and transportation fees	9,419	21,049	34,142	31,145
Oil marketing revenues	5,376	8,543	14,198	1,921
Total revenues	$ 215,903	$ 521,693	$ 1,260,360	$ 1,455,655

Note 5. Leases

We evaluate contracts for leasing arrangements at inception. We lease office space, equipment, and vehicles that have non-cancelable lease terms. Currently, our outstanding leases have remaining terms up to 7 years, with certain land leases having remaining terms up to 49 years. Leases with a term of 12 months or less are not recorded on our balance sheet. As part of the Chapter 11 Restructuring, the Predecessor elected to terminate some of its operating and finance leases, primarily related to office space. The table below reflects our operating lease right-of-use assets and operating lease liabilities, which primarily consist of our office leases:

	Successor	Predecessor
In thousands	December 31, 2020	December 31, 2019
Operating leases		
Operating lease right-of-use assets	$ 20,342	$ 34,099
Operating lease liabilities – current	$ 1,350	$ 6,901
Operating lease liabilities – long-term	19,460	41,932
Total operating lease liabilities	$ 20,810	$ 48,833

The majority of our leases contain renewal options, typically exercisable at our sole discretion. At emergence, we recorded right-of-use assets and liabilities based on the fair value of lease payments and utilized our incremental borrowing rate based on information available at the Emergence Date. The following weighted average remaining lease terms and discount rates related to our outstanding operating leases:

	Successor	Predecessor
	December 31, 2020	December 31, 2019
Weighted average remaining lease term	6.3 years	5.7 years
Weighted average discount rate	5.6 %	6.7 %

Lease costs for operating leases or leases with a term of 12 months or less are recognized on a straight-line basis over the lease term. For finance leases, interest on the lease liability and the amortization of the right-of-use asset are recognized separately, with the depreciable life reflective of the expected lease term. The Predecessor Company previously subleased part of the office space included in its operating leases for which it received rental payments. Since those office space leases were terminated during the Chapter 11 Restructuring, the underlying sublease agreements were also terminated. The Successor Company subsequently entered into an operating lease for a new corporate office space which commenced in October 2020. The following table summarizes the components of lease costs and sublease income:

		Successor	Predecessor	
In thousands	Income Statement	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	Year Ended Dec. 31, 2019
Operating lease cost	General and administrative expenses	$ 872	$ 5,683	$ 8,924
	Lease operating expenses	158	214	58
	CO_2 operating and discovery expenses	14	37	5
		$ 1,044	$ 5,934	$ 8,987
Finance lease cost				
Amortization of right-of-use assets	Depletion, depreciation, and amortization	$ 3	$ 9	$ 1,188
Interest on lease liabilities	Interest expense	1	3	40
Total finance lease cost		$ 4	$ 12	$ 1,228
Sublease income	General and administrative expenses	$ 100	$ 2,584	$ 4,127

Our statement of cash flows included the following activity related to our operating and finance leases:

	Successor	Predecessor	
In thousands	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	Year Ended Dec. 31, 2019
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash flows from operating leases	$ 341	$ 7,341	$ 10,995
Operating cash flows from interest on finance leases	1	3	40
Financing cash flows from finance leases	78	10	1,275
Right-of-use assets obtained in exchange for lease obligations			
Operating leases	19,902	1,049	415
Finance leases	—	162	—

The following table summarizes by year the maturities of our lease liabilities as of December 31, 2020:

In thousands	Operating Leases
2021	$ 2,496
2022	4,149
2023	4,135
2024	4,111
2025	4,149
Thereafter	6,263
Total minimum lease payments	25,303
Less: Amount representing interest	(4,493)
Present value of minimum lease liabilities	$ 20,810

Note 6. Asset Retirement Obligations

The following table summarizes the changes in our asset retirement obligations:

	Successor	Predecessor	
In thousands	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	Year Ended Dec. 31, 2019
Beginning asset retirement obligations	$ 163,368	$ 181,760	$ 176,585
Liabilities incurred and assumed during period	738	736	4,354
Revisions in estimated retirement obligations	22,660	3,592	9,206
Liabilities settled and sold during period	(3,439)	(10,041)	(24,342)
Accretion expense	2,954	11,329	15,957
Fresh start accounting adjustment	—	(24,008)	—
Ending asset retirement obligations	186,281	163,368	181,760
Less: current asset retirement obligations[(1)]	(6,943)	(4,930)	(4,652)
Long-term asset retirement obligations	$ 179,338	$ 158,438	$ 177,108

(1) Included in "Accounts payable and accrued liabilities" in our Consolidated Balance Sheets.

Liabilities assumed relate to minor acquisitions, with liabilities incurred generally relating to wells and facilities.

We have escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $55.2 million and $53.4 million as of December 31, 2020 and 2019, respectively. These balances are primarily invested in U.S. Treasury bonds, recorded at amortized cost, and money market accounts, which investments are included in "Other assets" in our Consolidated Balance Sheets. A portion of these investments are included in cash, cash equivalents, and restricted cash balances on our Consolidated Statements of Cash Flows (see Note 1, *Nature of Operations and Summary of Significant Accounting Policies – Cash, Cash Equivalents, and Restricted Cash*). The carrying values of these investments approximate their estimated fair market value as of December 31, 2020 and 2019.

Note 7. Unevaluated Property

A summary of the unevaluated property costs excluded from oil and natural gas properties being amortized at December 31, 2020, and the year in which the costs were incurred follows:

	December 31, 2020		
	Costs Incurred During:		
In thousands	Successor 2020	Fresh Start Adjustments (Sept. 18, 2020)[(1)]	Total
Property acquisition costs	$ —	$ 84,019	$ 84,019
Exploration and development	46	—	46
Capitalized interest	1,239	—	1,239
Total	$ 1,285	$ 84,019	$ 85,304

(1) Reflects the carrying values of our unevaluated properties as a result of the application of fresh start accounting upon emergence from bankruptcy (see Note 2, *Fresh Start Accounting*, for additional information) that remain in unevaluated properties as of December 31, 2020.

Our property acquisition costs reflected in the table above relate to fair values assigned during fresh start accounting and are primarily associated with our Cedar Creek Anticline fields and CO_2 tertiary potential at Tinsley, Oyster Bayou and Salt Creek fields. Exploration and development costs shown as unevaluated properties are primarily associated with our tertiary oil field projects that are under development but did not have associated proved reserves at December 31, 2020.

Costs are transferred into the amortization base on an ongoing basis as projects are evaluated and proved reserves established or impairment determined. We review the excluded properties for impairment at least annually. We currently estimate that evaluation of the majority of these properties and the inclusion of their costs in the amortization base is expected to be completed within five to ten years. Until we are able to determine whether there are any proved reserves attributable to the above costs, we are not able to assess the future impact on the amortization rate of the full cost pool.

Note 8. Long-Term Debt

The table below reflects long-term debt outstanding as of December 31, 2020 and 2019:

	Successor	Predecessor
In thousands	December 31, 2020	December 31, 2019
Successor Senior Secured Bank Credit Agreement	$ 70,000	$ —
Predecessor Senior Secured Bank Credit Agreement	—	—
9% Senior Secured Second Lien Notes due 2021	—	614,919
9¼% Senior Secured Second Lien Notes due 2022	—	455,668
7¾% Senior Secured Second Lien Notes due 2024	—	531,821
7½% Senior Secured Second Lien Notes due 2024	—	20,641
6⅜% Convertible Senior Notes due 2024	—	245,548
6⅜% Senior Subordinated Notes due 2021	—	51,304
5½% Senior Subordinated Notes due 2022	—	58,426
4⅝% Senior Subordinated Notes due 2023	—	135,960
Pipeline financings	68,008	167,439
Total debt principal balance	138,008	2,281,726
Debt discount	—	(101,767)
Future interest payable	—	164,914
Debt issuance costs	—	(10,009)
Total debt, net of debt issuance costs and discount	138,008	2,334,864
Less: current maturities of long-term debt	(68,008)	(102,294)
Long-term debt and capital lease obligations	$ 70,000	$ 2,232,570

The ultimate parent company in our corporate structure, Denbury Inc., is the sole issuer of all our outstanding obligations under our Successor Bank Credit Agreement. Denbury Inc. has no independent assets or operations. Each of the subsidiary guarantors of such obligations is 100% owned, directly or indirectly, by Denbury Inc, and the guarantees of such obligations are full and unconditional and joint and several.

Prior to our emergence from bankruptcy, our debt consisted of the Predecessor's Bank Credit Agreement, senior secured second lien notes, convertible senior notes, senior subordinated notes, pipeline financings, and capital lease obligations. On the Emergence Date, pursuant to the terms of the Plan, all outstanding obligations under the senior secured second lien notes, convertible senior notes, and senior subordinated notes were fully extinguished, relieving approximately $2.1 billion of debt by issuing equity and/or warrants in the Successor to the holders of that debt. See Note 1, *Nature of Operations and Summary of Significant Accounting Policies – Emergence from Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code*, for additional information.

Successor Senior Secured Bank Credit Facility

In connection with our emergence from Chapter 11 proceedings on September 18, 2020, we entered into a new credit agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (the "Successor Bank Credit Agreement"). The Successor Bank Credit Agreement is a senior secured revolving credit facility with an initial borrowing base and lender commitments of $575 million. Additionally, under the Successor Bank Credit Agreement, letters of credit are available in an aggregate amount not to exceed $100 million, and short-term swingline loans are available in an aggregate amount not to exceed $25 million, each subject to the available commitments under the Successor Bank Credit Agreement. Availability under the Successor Bank Credit Agreement is subject to a borrowing base, which is redetermined semiannually on or around May 1 and November 1 of each year, with our next scheduled redetermination around May 1, 2021. The borrowing base is adjusted at the lenders' discretion and is based, in part, upon external factors over which we have no control. The borrowing base is subject to a reduction by twenty-five percent (25%) of the principal amount of any unsecured or subordinated debt issued or incurred. The borrowing base may also be reduced if we sell borrowing base properties and/or cancel commodity derivative positions with an aggregate value in excess of 5% of the then-effective borrowing base between redeterminations. If our outstanding debt under the Successor Bank Credit Agreement exceeds the then-effective borrowing base, we would be required to repay the excess amount over a period not to exceed six months. The Successor Bank Credit Agreement matures on January 30, 2024.

The Successor Bank Credit Agreement prohibits us from paying dividends on our common stock through September 17, 2021. Commencing on September 18, 2021, we may pay dividends on our common stock or make other restricted payments in an amount not to exceed Distributable Free Cash Flow (as defined in the Successor Bank Credit Agreement), but only if (1) no event of default or borrowing base deficiency exists; (2) our total leverage ratio is 2 to 1 or lower; and (3) availability under the Successor Bank Credit Agreement is at least 20%. The Successor Bank Credit Agreement also limits our ability to, among other things, incur and repay other indebtedness; grant liens; engage in certain mergers, consolidations, liquidations and dissolutions; engage in sales of assets; make acquisitions and investments; make other restricted payments (including redeeming, repurchasing or retiring our common stock); and enter into commodity derivative agreements, in each case subject to customary exceptions.

The Successor Bank Credit Agreement is secured by (1) our proved oil and natural gas properties, which are held through our restricted subsidiaries; (2) the pledge of equity interests of such subsidiaries; (3) a pledge of our commodity derivative agreements; (4) a pledge of deposit accounts, securities accounts and commodity accounts of Denbury Inc. and such subsidiaries (as applicable); and (5) a security interest in substantially all other collateral that may be perfected by a Uniform Commercial Code filing, subject to certain exceptions.

The Successor Bank Credit Agreement contains certain financial performance covenants including the following:

- A Consolidated Total Debt to Consolidated EBITDAX covenant, with such ratio not to exceed 3.5 times; and
- A requirement to maintain a current ratio (i.e., Consolidated Current Assets to Consolidated Current Liabilities) of at least 1.0 times.

For purposes of computing the current ratio per the Successor Bank Credit Agreement, Consolidated Current Assets exclude the current portion of derivative assets but include available borrowing capacity under the Successor Bank Credit Agreement, and Consolidated Current Liabilities exclude the current portion of derivative liabilities as well as the current portions of long-term indebtedness outstanding.

Loans under the Successor Bank Credit Agreement are subject to varying rates of interest based on either (1) for ABR Loans, a base rate determined under the Successor Bank Credit Agreement (the "ABR") plus an applicable margin ranging from 2% to 3% per annum, or (b) for LIBOR Loans, the LIBOR rate (subject to a 1% floor) plus an applicable margin ranging from 3% to 4% per annum (capitalized terms as defined in the Successor Bank Credit Agreement). The weighted average interest rate on borrowings outstanding as of December 31, 2020 under the Successor Bank Credit Agreement was 4.0%. The undrawn portion of the aggregate lender commitments under the Successor Bank Credit Agreement is subject to a commitment fee of 0.5%. As of December 31, 2020, we were in compliance with all debt covenants under the Successor Bank Credit Agreement.

The above description of our Successor Bank Credit Agreement and defined terms are contained in the Successor Bank Credit Agreement.

Restructuring of Pipeline Financing Transactions

In May 2008, we closed two transactions with Genesis Energy, L.P. (“Genesis”) involving two of our pipelines. The NEJD pipeline system included a 20-year secured financing lease, and the Free State Pipeline included a long-term transportation service agreement. On August 7, 2020, Genesis, as the beneficiary of the $41.3 million letter of credit issued as financial assurances under the NEJD pipeline lease financing, drew the full amount of such letter of credit in accordance with its terms as a result of the Predecessor’s Chapter 11 Restructuring, which resulted in a corresponding reduction to the principal balance outstanding under such financing. In late October 2020, we restructured our CO_2 pipeline financing arrangements with Genesis, whereby (1) Denbury reacquired the NEJD pipeline system from Genesis in exchange for $70 million to be paid in four equal payments during 2021, representing full settlement of all remaining obligations under the NEJD secured financing lease; and (2) Denbury reacquired the Free State Pipeline from Genesis in exchange for a one-time payment of $22.5 million on October 30, 2020.

Predecessor Senior Secured Bank Credit Facility

From December 2014 through September 18, 2020, the Company maintained a senior secured revolving credit facility with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (the “Predecessor Bank Credit Agreement”). All but a minor portion of the Predecessor Bank Credit Agreement was refinanced through the DIP Facility from August 4, 2020 through September 18, 2020, which was in turn refinanced by the Successor Bank Credit Agreement upon emergence from the Chapter 11 Restructuring.

Extinguishment of Predecessor Senior Secured Second Lien Notes, Convertible Senior Notes, and Senior Subordinated Notes

Upon emergence from the Chapter 11 Restructuring on September 18, 2020, the Predecessor’s 9% Senior Secured Second Lien Notes due 2021 (the “2021 Notes”), 9¼% Senior Secured Second Lien Notes due 2022, 7¾% Senior Secured Second Lien Notes due 2024 (the “7¾% Senior Secured Notes”), 7½% Senior Secured Second Lien Notes due 2024 (the “7½% Senior Secured Notes”), 6⅜% Convertible Senior Notes due 2024 (the “2024 Convertible Notes”), 6⅜% Senior Subordinated Notes due 2021 (the “Subordinated 2021 Notes”), 5½% Senior Subordinated Notes due 2022 (the “Subordinated 2022 Notes”), and 4⅝% Senior Subordinated Notes due 2023 (the “Subordinated 2023 Notes”) were fully extinguished by issuing equity and/or warrants in the Successor to the holders of that debt. The Predecessor debt discussions that follow are included to provide context on the impact of these transactions on the Predecessor’s financial statements.

Second Quarter 2020 Conversion of 2024 Convertible Notes

During the second quarter of 2020, holders of $19.9 million aggregate principal amount outstanding of the Predecessor’s 2024 Convertible Notes converted their notes into shares of the Predecessor’s common stock, at the rates specified in the indenture for the notes, resulting in the issuance of 7.4 million shares of Predecessor common stock upon conversion. The debt principal balance, net of debt discounts, totaling $13.9 million, was reclassified to “Paid-in capital in excess of par” and “Common stock” in the Consolidated Balance Sheet of the Predecessor upon the conversion of the notes into shares of Predecessor common stock.

First Quarter 2020 Repurchases of Senior Secured Notes

During March 2020, the Predecessor repurchased a total of $30.2 million aggregate principal amount of its 2021 Notes in open-market transactions for a total purchase price of $14.2 million, excluding accrued interest. In connection with these transactions, the Predecessor recognized a $19.0 million gain on debt extinguishment, net of unamortized debt issuance costs and future interest payable written off.

2019 Predecessor Debt Reduction Transactions

During the third quarter of 2019, the Predecessor repurchased $11.0 million in aggregate principal amount of its then outstanding Subordinated 2022 Notes in open market transactions for a total purchase price of $5.3 million, excluding accrued interest. Additionally, during the fourth quarter of 2019, the Predecessor repurchased principally through exchanges an additional $25.3 million in aggregate principal amount of its then outstanding Subordinated 2022 Notes and $75.7 million in aggregate principal amount of its then outstanding Subordinated 2023 Notes for $11.2 million in cash and issuance of 38.3 million shares of the Predecessor's common stock. In connection with these transactions, the Predecessor recognized a $55.5 million gain on debt extinguishment, net of unamortized debt issuance costs written off, during the year ended December 31, 2019, in its Consolidated Statements of Operations.

During June 2019, in a series of debt exchanges, the Predecessor extended the maturities of its outstanding long-term debt and reduced the amount of outstanding debt principal. As part of these transactions, holders exchanged a total of $468.4 million aggregate principal amount of the Predecessor's then outstanding senior subordinated notes for $102.6 million aggregate principal amount of 7¾% Senior Secured Notes, $245.5 million aggregate principal amount of 2024 Convertible Notes and $120.0 million of cash. The exchanged senior subordinated notes consisted of $152.2 million aggregate principal amount of Subordinated 2021 Notes, $219.9 million aggregate principal amount of Subordinated 2022 Notes and $96.3 million aggregate principal amount of Subordinated 2023 Notes. In addition, holders also exchanged $425.4 million of 7½% Senior Secured Notes for $425.4 million aggregate principal amount of 7¾% Senior Secured Notes. In July 2019, holders exchanged an additional $4.0 million aggregate principal amount of 7½% Senior Secured Notes for $3.8 million aggregate principal amount of 7¾% Senior Secured Notes. As a result, the Predecessor recognized a noncash gain on debt extinguishment, net of transaction costs, totaling $100.5 million for the year ended December 31, 2019, in its Consolidated Statements of Operations.

In accordance with FASC 470-50, *Modifications and Extinguishments*, the June 2019 exchange of the Predecessor's existing senior subordinated notes was accounted for as a debt extinguishment. Therefore, the 7¾% Senior Secured Notes and 2024 Convertible Notes were recorded on the balance sheet at fair market value based upon initial trading prices following their issuance, resulting in a discount to their principal amount of $22.6 million and $79.9 million, respectively.

Separately, the June 2019 exchange of the Predecessor's existing senior secured second lien notes was accounted for as a modification of those notes. Therefore, no gain or loss was recognized, and previously deferred debt issuance costs of $6.9 million were treated as a discount to the principal amount of the 7¾% Senior Secured Notes.

Debt Issuance Costs

In connection with the issuance of our outstanding long-term debt, we have incurred debt issuance costs, which are being amortized to interest expense using the straight line or effective interest method over the term of each related facility or borrowing. Remaining unamortized debt issuance costs were $8.4 million and $14.0 million at December 31, 2020 (Successor) and 2019 (Predecessor), respectively. Issuance costs associated with our Successor Bank Credit Agreement (Successor period) and Predecessor Bank Credit Agreement (Predecessor period) are included in "Other assets" in the Consolidated Balance Sheets, and issuance costs associated with the Predecessor's senior secured second lien notes, convertible senior notes, and senior subordinated notes are included as a reduction of "Long-term debt, net of current portion" in the Consolidated Balance Sheets for the Predecessor period.

Indebtedness Repayment Schedule

At December 31, 2020, our indebtedness is payable over the next five years and thereafter as follows:

In thousands	
2021	$ 68,008
2022	—
2023	—
2024	70,000
2025	—
Thereafter	—
Total indebtedness	$ 138,008

Note 9. Income Taxes

Our income tax provision (benefit) is as follows:

	Successor	Predecessor		
	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	Year Ended December 31,	
In thousands			2019	2018
Current income tax expense (benefit)				
Federal	$ —	$ (6,407)	$ 2,645	$ (17,885)
State	30	(853)	1,236	1,884
Total current income tax expense (benefit)	30	(7,260)	3,881	(16,001)
Deferred income tax expense (benefit)				
Federal	—	(319,011)	89,950	93,395
State	(2,556)	(89,858)	10,521	9,839
Total deferred income tax expense (benefit)	(2,556)	(408,869)	100,471	103,234
Total income tax expense (benefit)	$ (2,526)	$ (416,129)	$ 104,352	$ 87,233

At December 31, 2020, we had no federal net operating loss carryforwards ("NOLs"), tax effected business interest expense carryforward, or tax credits, as the Company's federal tax attributes were fully reduced in accordance with the attribute reduction and ordering rules of Section 108 of the Internal Revenue Code of 1986 pertaining to discharge of indebtedness. At December 31, 2020, we had $0.6 million of alternative minimum tax credits, which under the Tax Cut and Jobs Act passed in 2017 will be fully refundable by 2021, and are recorded as a receivable on the balance sheet, and state NOLs and tax credits totaling $56.0 million (before provision for valuation allowance) related to all our state operations, which continue as carryforwards for the Successor. Our state NOLs expire in various years, starting in 2025.

Deferred income taxes reflect the available tax carryforwards and the temporary differences based on tax laws and statutory rates in effect at the December 31, 2020 and 2019 balance sheet dates. As of December 31, 2020, we had $75.1 million of net state deferred tax assets associated with operations in Louisiana, Mississippi, Montana, North Dakota and Alabama, which were fully offset with valuation allowances. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized.

The changes in our valuation allowance are detailed below:

	Successor	Predecessor		
			Year Ended	
In thousands	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	Dec. 31, 2019	Dec. 31, 2018
Beginning balance	$ 129,840	$ 77,215	$ 51,093	$ 51,134
Charges	2,269	77,138	26,122	—
Deductions	(2,701)	(24,513)	—	(41)
Ending balance	$ 129,408	$ 129,840	$ 77,215	$ 51,093

As of December 31, 2020, we had no unrecognized tax benefits recorded related to an uncertain tax position.

Significant components of our deferred tax assets and liabilities as of December 31, 2020 and 2019 are as follows:

	Successor	Predecessor
In thousands	December 31, 2020	December 31, 2019
Deferred tax assets		
Property and equipment	$ 59,207	$ —
Loss and tax credit carryforwards – state	55,979	52,917
Accrued liabilities and other reserves	15,632	29,788
Derivative contracts	13,090	—
Lease liabilities	6,354	10,841
Business interest expense carryforward	—	24,513
Business credit carryforwards	—	71,555
Unrecognized gain and original issue discount on debt exchange	—	41,556
Other	4,092	15,664
Valuation allowances	(129,408)	(77,215)
Total deferred tax assets	24,946	169,619
Deferred tax liabilities		
CO_2 and other contracts	(20,030)	—
Operating lease right-of-use assets	(6,190)	(7,780)
Property and equipment	—	(569,254)
Derivative contracts	—	(1,120)
Other	—	(1,695)
Total deferred tax liabilities	(26,220)	(579,849)
Total net deferred tax liability	$ (1,274)	$ (410,230)

Our reconciliation of income tax expense computed by applying the U.S. federal statutory rate and the reported effective tax rate on income from continuing operations is as follows:

	Successor	Predecessor		
	Period from Sept. 19, 2020 through	Period from Jan. 1, 2020 through	Year Ended December 31,	
In thousands	Dec. 31, 2020	Sept. 18, 2020	2019	2018
Income tax provision calculated using the federal statutory income tax rate	$ (11,169)	$ (388,228)	$ 67,475	$ 86,086
State income taxes, net of federal income tax benefit	(2,532)	(86,937)	7,435	11,968
Tax shortfall (windfall) on stock-based compensation deduction	—	(1,502)	1,912	(1,565)
Valuation allowance	9,653	19,344	26,122	(42)
Tax attributes reduction – net of CODI exclusion	—	31,667	—	—
Enhanced oil recovery tax credits generated	—	—	—	(10,818)
Other	1,522	9,527	1,408	1,604
Total income tax expense (benefit)	$ (2,526)	$ (416,129)	$ 104,352	$ 87,233

We file consolidated and separate income tax returns in the U.S. federal jurisdiction and in many state jurisdictions. The statutes of limitation for our income tax returns for tax years ending prior to 2017 have lapsed and therefore are not subject to examination by respective taxing authorities. We have not paid any significant interest or penalties associated with our income taxes.

Note 10. Stockholders' Equity

Registration Rights Agreement

On the Emergence Date, the Company entered into a registration rights agreement (the "Registration Rights Agreement") with certain former beneficial holders of the second lien notes of the Predecessor who entered into the RSA dated July 28, 2020, and that together with their affiliates received 4% or more of New Common Stock (including shares to which they are entitled upon exercise of series A warrants of the Successor) pursuant to the Plan, or their affiliates.

Under the Registration Rights Agreement, security holders have customary demand and piggyback registration rights, subject to the limitations set forth in the Registration Rights Agreement. Securityholders have the right to demand the Company to effectuate the distribution of any or all of its Registrable Securities (as defined in the Registration Rights Agreement) by means of an underwritten offering pursuant to an effective registration statement; provided, however, that the expected aggregate offering price is equal to or greater than $25.0 million or includes at least 20% of the then-outstanding Registrable Securities.

These registration rights are subject to certain conditions and limitations, including the right of the underwriters to limit the number of shares to be included in an offering and the Company's right to delay or withdraw a registration statement under certain circumstances. The Company will generally pay all registration expenses in connection with its obligations under the Registration Rights Agreement, regardless of whether a registration statement is filed or becomes effective. The registration rights granted in the Registration Rights Agreement are subject to customary indemnification and contribution provisions, as well as customary restrictions such as blackout periods and, if an underwritten offering is contemplated, limitations on the number of shares to be included in the underwritten offering that may be imposed by the managing underwriter.

401(k) Plan

We offer a 401(k) plan to which employees may contribute earnings subject to IRS limitations. We match 100% of an employee's contribution, up to 6% of compensation, as defined by the plan, which is vested immediately. Matching contributions to the 401(k) plan totaled $1.1 million for the period September 19, 2020 through December 31, 2020

(Successor) and $4.4 million for the period January 1, 2020 through September 18, 2020 (Predecessor). During 2019 and 2018, our matching contributions to the 401(k) plan were approximately $6.3 million and $6.2 million, respectively.

Note 11. Stock Compensation

Below is a description of stock compensation relating to both the Predecessor periods (2018, 2019 and January 1, 2020 through September 18, 2020) and the Successor period (September 19, 2020 through December 31, 2020). All stock compensation plans and awards in effect during the Predecessor periods were cancelled upon emergence of the Company from its Chapter 11 Restructuring on September 18, 2020. The plans and awards described below which are designated as Successor plans or awards are the only such plans and awards in effect as of December 31, 2020. Each of the plans and awards described below are designated as either Predecessor or Successor, with the exception of the section labeled "*Stock-Based Compensation – Predecessor and Successor*" which pertains to both Predecessor and Successor periods.

Stock-based Compensation – Predecessor and Successor

Stock-based compensation expense is included in "General and administrative expenses" in the Consolidated Statements of Operations. Stock-based compensation associated with our employees involved in exploration and drilling activities is capitalized as part of "Oil and natural gas properties" in the Consolidated Balance Sheets. Our accounting policy is to account for forfeitures as they occur.

The following table sets forth stock-based compensation costs for the periods indicated:

	Successor	Predecessor		
	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	Year Ended December 31,	
In thousands			2019	2018
Stock-based compensation expense included in G&A	$ 8,212	$ 4,111	$ 12,470	$ 11,951
Stock-based compensation capitalized	695	1,660	4,018	3,487
Total cost of stock-based compensation arrangements	$ 8,907	$ 5,771	$ 16,488	$ 15,438
Income tax benefit recognized for stock-based compensation arrangements	$ 2,053	$ 1,028	$ 3,118	$ 2,988

Management Incentive Plan – Successor

In connection with our emergence from bankruptcy, the Plan provided for the adoption of a management incentive plan, the Denbury Inc. 2020 Omnibus Stock and Incentive Plan (the "LTIP"), effective as of the Emergence Date, through an amendment and restatement of the Denbury Resources Inc. Amended and Restated 2004 Omnibus Stock and Incentive Plan, as amended and restated as of March 26, 2020. The LTIP reserved 6.2 million shares of Denbury's common stock for awards to officers, other employees, directors and other service providers. The LTIP provides for, among other things, the grant of incentive stock options, nonstatutory stock options, restricted stock, restricted stock units, stock appreciation rights, dividend equivalents, other stock-based awards, cash awards, or any combination of the foregoing. On December 2, 2020, Denbury's board of directors approved and ratified the LTIP, with initial awards covering 2.2 million shares of common stock granted on December 4, 2020. As of December 31, 2020, 4.0 million shares were available for future grants under the LTIP, all of which could be issued in the form of restricted stock units or performance stock units. Our incentive compensation program is administered by the Compensation Committee of our Board of Directors. The LTIP will expire September 2030.

Restricted Stock Units – Successor

In December 2020, non-performance-based restricted stock unit ("RSU") awards were granted to directors and a limited number of employees under the Successor's LTIP. Holders of non-performance-based RSUs will receive shares of Successor common stock equal to the number of RSUs that have vested upon settlement. Non-performance-based RSUs generally vest over a three-year vesting period with delivery of the shares occurring at the end of the three-year vesting period. Shares to be delivered to participants are expected to be made available from authorized but unissued shares reserved under the LTIP. The grant-date fair value of the RSUs is based on the fair market value of our common stock on the date of grant.

As of December 31, 2020, there was $29.3 million of unrecognized compensation expense related to the Successor's nonvested non-performance-based restricted stock unit grants. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 2.9 years.

A summary of the status of our nonvested non-performance-based RSUs issued and the changes during the Successor period is presented below:

	Number of Awards	Weighted Average Grant-Date Fair Value
Nonvested at September 19, 2020 (Successor)	—	$ —
Granted	1,219,867	24.67
Vested	—	—
Forfeited	—	—
Nonvested at December 31, 2020 (Successor)	1,219,867	24.67

Performance-Based Stock Units – Successor

In December 2020, the Successor Board of Directors granted performance stock unit ("PSU") awards to a limited number of employees. The PSU awards vest based on Denbury's stock price reaching certain levels (based on the daily volume-weighted average common stock price on the New York Stock Exchange ("NYSE") for any consecutive 60-day trading period), as shown in the table below, but delivery of the shares will not occur until the conclusion of the three-year performance period. Shares to be delivered to participants are expected to be made available from authorized but unissued shares reserved under the LTIP.

Tier	Stock Price Hurdle	Cumulative Percentage of PSUs Granted Hereunder that Become [1]
0	Less than $18.75	0%
1	$18.75	25%
2	$21.00	50%
3	$23.25	75%
4	$25.75	100%

(1) If the 60-day volume-weighted average price falls between the Stock Price Hurdles in Tier 1, 2, 3 or 4, then the cumulative percentage of PSUs granted that become vested shall be calculated using straight-line interpolation between the corresponding percentages in the table above.

PSU awards are valued using a Monte Carlo simulation. Expected volatilities utilized in the model were estimated using historical volatility of the Predecessor stock over a look-back term generally equivalent to the expected life of the award from the grant date.

As of December 31, 2020, there was $16.6 million of unrecognized compensation expense related to the Successor's nonvested PSU awards. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 0.2 years, though the underlying shares will not be delivered until the conclusion of the three-year performance period. The range of assumptions used in the Monte Carlo simulation valuation approach is as follows:

	Successor
	Period from Sept. 19, 2020 through Dec. 31, 2020
Weighted average fair value of PSU awards granted	$ 24.19
Risk-free interest rate	0.21 %
Expected life	0.23 years
Expected volatility	110.0 %
Dividend yield	— %

A summary of the status of the nonvested PSU awards during the Successor period is as follows:

	Number of Awards	Weighted Average Grant-Date Fair Value
Nonvested at September 19, 2020 (Successor)	—	$ —
Granted	1,021,222	24.19
Vested	—	—
Forfeited	—	—
Nonvested at December 31, 2020 (Successor)	1,021,222	24.19

June 2020 Compensation Adjustments – Predecessor

In response to the then ongoing significant economic and market uncertainty affecting the oil and gas industry, in June 2020 the Predecessor and its Board of Directors and Compensation Committee implemented a revised compensation structure under which for 21 of the Company's executives (including our named executive officers) and senior managers, all outstanding equity awards and 2020 targeted variable cash-based compensation were canceled and replaced with a cash retention incentive. In total, $15.2 million in cash retention incentives were prepaid to those employees in June 2020, with an obligation of the executives to repay up to 100% of the compensation (on an after-tax basis) if specified conditions were not satisfied. The Predecessor's named executive officers' cash retention incentives were earned 50% based on their continued employment for a period of up to 12 months and 50% based on achieving certain specified incentive metrics.

In accordance with FASC Topic 718, *Compensation – Stock Compensation*, we accounted for the transaction involving equity compensation as an award modification and reclassified the awards from equity to liability awards. As a result of the modification of the awards, unrecognized compensation at the time of modification was determined to be $18.7 million ($4.1 million of incremental compensation expense), which was higher than the $15.2 million cash payment, and was calculated as the greater of (i) grant date fair value of the previously-outstanding awards plus incremental compensation (defined as cash paid related to the cash retention incentive in excess of the modification date fair value of the previously-existing awards) or (ii) cash paid for the cash retention incentive for each award. The value was recognized as total compensation expense for each award over the service period. The compensation expense was recognized in "General and administrative expenses" in the Consolidated Statements of Operations during the period January 1, 2020 through September 18, 2020 (Predecessor). The accounting for the Predecessor's remaining share-based compensation awards continued throughout the period covered by the Chapter 11 Restructuring, and upon cancellation of the awards, an additional $4.6 million of compensation expense was recognized during the Predecessor period ended September 18, 2020.

2004 Omnibus Stock and Incentive Plan – Predecessor

The Amended and Restated 2004 Omnibus Stock and Incentive Plan, amended and restated as of March 26, 2020 (the "2004 Plan"), was an incentive plan that provided for the issuance of incentive and non-qualified stock options, restricted stock awards, restricted stock units, stock appreciation rights ("SARs") settled in stock, and performance-based awards to officers, employees and directors. Since the 2004 Plan's inception, awards covering a total of 61.4 million shares of common stock were authorized for issuance pursuant to the 2004 Plan. In connection with our emergence from bankruptcy, all outstanding equity as of September 18, 2020 was cancelled.

SARs – Predecessor

Prior to January 1, 2016, the Predecessor granted SARs settled in stock to employees. The SARs generally became exercisable over a three-year vesting period, with the specific terms of vesting determined at the time of grant based on guidelines established by the Predecessor's Compensation Committee of the Board of Directors. The SARs expired over terms not to exceed 7 years from the date of grant, 90 days after termination of employment, 90 days or one year after permanent disability, depending on the award, or one year after the death of the optionee. The SARs were granted with a strike price equal to the fair market value at the time of grant, which was equal to the closing price on the NYSE on the date of grant.

The following is a summary of the Predecessor's SAR activity:

	Number of Awards	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2019 (Predecessor)	1,981,156	$ 9.12		
Granted	—	—		
Exercised	—	—		
Forfeited	—	—		
Expired	(580,087)	12.38		
Cancelled	(1,401,069)	7.77		
Outstanding at September 18, 2020 (Predecessor)	—	—	—	$ —
Exercisable at end of period	—	$ —	—	$ —

As of December 31, 2018, all SARs vested and there was no remaining compensation cost to be recognized in future periods related to nonvested share-based SAR compensation arrangements. The grant-date fair value of SARs vested during the year ended December 31, 2018 was $1.1 million. There were no exercises of SARs for the period January 1, 2020 through September 18, 2020 (Predecessor) or the years ended December 31, 2019 and 2018. In connection with our emergence from bankruptcy, all SARs outstanding as of September 18, 2020 were cancelled.

Restricted Stock – Predecessor

During the Predecessor period, we granted non-performance-based restricted stock to employees and directors as part of our long-term compensation program. Holders of non-performance-based restricted stock awards had the rights of owning non-restricted stock (including voting rights) except that the holders were not entitled to delivery of a portion thereof until certain requirements were met. Beginning in 2014, non-performance-based restricted stock awards provided the holders with forfeitable dividend equivalent rights which vested with the underlying shares. Non-performance-based restricted stock vested over a three-year vesting period, with the specific terms of vesting determined at the time of grant.

The following is a summary of the total vesting date fair value of non-performance-based restricted stock:

	Predecessor		
	Period from Jan. 1, 2020 through	Year Ended December 31,	
In thousands	Sept. 18, 2020	2019	2018
Fair value of restricted stock vested	$ 707	$ 5,743	$ 23,060

A summary of the status of our nonvested non-performance-based restricted stock grants issued and the changes during the Predecessor period is presented below:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2019 (Predecessor)	12,407,436	$ 1.91
Granted	—	—
Vested	(2,743,473)	2.10
Forfeited	—	—
Cancelled	(9,663,963)	1.85
Nonvested at September 18, 2020 (Predecessor)	—	—

In connection with our emergence from bankruptcy, all restricted stock outstanding as of September 18, 2020 was cancelled and there was no remaining compensation cost to be recognized in future periods related to nonvested non-performance-based restricted stock arrangements.

Performance-Based Equity Awards – Predecessor

The Predecessor's Compensation Committee of the Board of Directors annually granted performance-based equity awards to Denbury's officers. Performance-based awards generally vested over 3.25 years for awards granted in 2018, 2019 and 2020. The number of performance-based shares earned (and eligible to vest) during the performance period was dependent upon: (1) the level of success in achieving specifically identified performance targets ("Performance-Based Operational Awards") and (2) performance of the Predecessor's stock relative to that of a designated peer group ("Performance-Based TSR Awards"). As discussed above, in conjunction with our 2020 compensation adjustments, all outstanding Predecessor performance-based equity awards were canceled and replaced with a cash retention incentive in June 2020.

Performance-Based Operational Awards were valued using the fair market value of the Predecessor's stock, and Performance-Based TSR Awards were valued using a Monte Carlo simulation. Expected volatilities utilized in the model were estimated using historical volatility of the Predecessor stock over a look-back term generally equivalent to the expected life of the award from the grant date. The range of assumptions used in the Monte Carlo simulation valuation approach for Performance-Based TSR Awards (presented at the target level) is as follows:

	Predecessor		
	Period from Jan. 1, 2020 through	Year Ended December 31,	
	Sept. 18, 2020	2019	2018
Weighted average fair value of Performance-Based TSR Awards granted	$ 0.15	$ 1.95	$ 2.29
Risk-free interest rate	0.27 %	2.27 %	2.37 %
Expected life	3.0 years	3.0 years	3.0 years
Expected volatility	89.6 %	77.2 %	102.9 %
Dividend yield	— %	— %	— %

A summary of the status of the nonvested performance-based equity awards (presented at the target level) during the Predecessor period is as follows:

	Performance-Based Operational Awards		Performance-Based TSR Awards	
	Number of Awards	Weighted Average Grant-Date Fair Value	Number of Awards	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2019 (Predecessor)	1,838,584	$ 2.27	4,475,998	$ 2.65
Granted(1)	—	—	3,041,774	0.15
Vested(2)	—	—	(742,996)	3.42
Forfeited	(102,469)	2.28	(385,183)	1.26
Cancelled	(1,736,115)	2.27	(6,389,593)	1.23
Nonvested at September 18, 2020 (Predecessor)	—	—	—	—

(1) Amounts granted reflect the number of performance units granted. The actual payout of the shares were between 0% and 200%, with any amounts earned above the 100% target levels payable in cash, rather than in shares of stock, in order to conserve available shares.
(2) During 2020, the service period lapsed on these TSR performance unit awards. The lapsed units earned a weighted average of 59% of target for each vested TSR performance-based award, representing 438,363 aggregate shares of Predecessor common stock issued. There were no vestings related to the Predecessor's Operational performance-based awards during 2020.

The following is a summary of the total vesting date fair value of performance-based equity awards for the Predecessor:

	Predecessor		
	Period from Jan. 1, 2020 through Sept. 18, 2020	Year Ended December 31,	
In thousands		2019	2018
Vesting date fair value of Performance-Based Operational Awards	$ —	$ —	$ 595
Vesting date fair value of Performance-Based TSR Awards	79	2,783	542

Note 12. Commodity Derivative Contracts

We do not apply hedge accounting treatment to our oil and natural gas derivative contracts; therefore, the changes in the fair values of these instruments are recognized in income in the period of change. These fair value changes, along with the settlements of expired contracts, are shown under "Commodity derivatives expense (income)" in our Consolidated Statements of Operations.

Historically, we have entered into various oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps, fixed-price swaps enhanced with a sold put, and basis swaps. The production that we hedge has varied from year to year depending on our levels of debt, financial strength and expectation of future commodity prices. Under the terms of our Successor Bank Credit Agreement, by December 31, 2020, we were required to have hedges in place covering a minimum of 65% of our anticipated crude oil production for the twelve calendar months between August 1, 2020 through July 31, 2021 and 35% of our anticipated crude oil production for the second twelve calendar months between August 1, 2021 through July 31, 2022. As of December 31, 2020, we were in compliance with the hedging requirements of our Successor Bank Credit Agreement.

We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification, and all of our commodity derivative contracts are with parties that are lenders under our Successor Bank Credit Agreement (or affiliates of such lenders). As of December 31, 2020, all of our outstanding derivative contracts were subject to enforceable master netting arrangements whereby payables on those contracts can be offset against receivables from separate derivative contracts with the same counterparty. It is our policy to classify derivative assets and liabilities on a gross basis on our balance sheets, even if the contracts are subject to enforceable master netting arrangements.

The following table summarizes our commodity derivative contracts as of December 31, 2020, none of which are classified as hedging instruments in accordance with the FASC *Derivatives and Hedging* topic:

			Contract Prices ($/Bbl)					
					Weighted Average Price			
Months	Index Price	Volume (Barrels per day)	Range[(1)]		Swap	Sold Put	Floor	Ceiling
Oil Contracts:								
2021 Fixed-Price Swaps								
Jan – Dec	NYMEX	26,000	$ 38.68 –	47.69	$ 42.54	$ —	$ —	$ —
2021 Collars								
Jan – Dec	NYMEX	3,000	$ 45.00 –	51.30	$ —	$ —	$ 45.00	$ 50.95
2022 Fixed-Price Swaps								
Jan – June	NYMEX	8,500	$ 42.65 –	45.50	$ 43.55	$ —	$ —	$ —

(1) Ranges presented for fixed-price swaps represent the lowest and highest fixed prices of all open contracts for the period presented. For collars, ranges represent the lowest floor price and the highest ceiling price for all open contracts for the period presented.

Note 13. Fair Value Measurements

The FASC *Fair Value Measurement* topic defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (often referred to as the "exit price"). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the income approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The FASC establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

- Level 1 – Quoted prices in active markets for identical assets or liabilities as of the reporting date.
- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. Instruments in this category include non-exchange-traded oil derivatives that are based on NYMEX and regional pricing other than NYMEX (e.g., Light Louisiana Sweet). Our costless collars and the sold put features of our three-way collars are valued using the Black-Scholes model, an industry standard option valuation model that takes into account inputs such as contractual prices for the underlying instruments, maturity, quoted forward prices for commodities, interest rates, volatility factors and credit worthiness, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

- Level 3 – Pricing inputs include significant inputs that are generally less observable. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. As of December 31, 2019, instruments in this category included non-exchange-traded three-way collars that were based on regional pricing other than NYMEX (e.g., Light Louisiana Sweet). The valuation models utilized for three-way collars were consistent with the methodologies described above; however, the implied volatilities utilized in the valuation of Level 3 instruments were developed using a benchmark, which was considered a significant unobservable input.

We adjust the valuations from the valuation model for nonperformance risk, using our estimate of the counterparty's credit quality for asset positions and our credit quality for liability positions. We use multiple sources of third-party credit data in determining counterparty nonperformance risk, including credit default swaps.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2020 and 2019:

	Fair Value Measurements Using:			
In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2020 (Successor)				
Assets				
Oil derivative contracts – current	$ —	$ 187	$ —	$ 187
Total Assets	$ —	$ 187	$ —	$ 187
Liabilities				
Oil derivative contracts – current	$ —	$ (53,865)	$ —	$ (53,865)
Oil derivative contracts – long-term	—	(5,087)	—	(5,087)
Total Liabilities	$ —	$ (58,952)	$ —	$ (58,952)
December 31, 2019 (Predecessor)				
Assets				
Oil derivative contracts – current	$ —	$ 8,503	$ 3,433	$ 11,936
Total Assets	$ —	$ 8,503	$ 3,433	$ 11,936
Liabilities				
Oil derivative contracts – current	$ —	$ (6,522)	$ (1,824)	$ (8,346)
Total Liabilities	$ —	$ (6,522)	$ (1,824)	$ (8,346)

Since we do not apply hedge accounting for our commodity derivative contracts, any gains and losses on our assets and liabilities are included in "Commodity derivatives expense (income)" in the accompanying Consolidated Statements of Operations.

Level 3 Fair Value Measurements

The following table summarizes the changes in the fair value of our Level 3 assets and liabilities for the periods indicated:

	Successor	Predecessor	
In thousands	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	Year Ended Dec. 31, 2019
Fair value of Level 3 instruments, beginning of period	$ —	$ 1,609	$ 13,624
Transfers out of Level 3	—	(1,609)	—
Fair value adjustments on commodity derivatives	—	—	(8,205)
Receipt on settlements of commodity derivatives	—	—	(3,810)
Fair value of Level 3 instruments, end of period	$ —	$ —	$ 1,609
The amount of total losses for the period included in earnings attributable to the change in unrealized losses relating to assets or liabilities still held at the reporting date	$ —	$ —	$ (556)

Instruments previously categorized as Level 3 included non-exchange-traded three-way collars that were based on regional pricing other than NYMEX, whereby the implied volatilities utilized were developed using a benchmark, which was considered a significant unobservable input. The transfers between Level 3 and Level 2 during the period generally relate to changes in the significant relevant observable and unobservable inputs that are available for the fair value measurements of such financial instruments.

Other Fair Value Measurements

The carrying value of our loans under our Successor Bank Credit Agreement approximate fair value, as they are subject to short-term floating interest rates that approximate the rates available to us for those periods. We use a market approach to determine the fair value of our fixed-rate long-term debt using observable market data. The fair values of the Predecessor's senior secured second lien notes, convertible senior notes, and senior subordinated notes were based on quoted market prices, which are considered Level 1 measurements under the fair value hierarchy. The estimated fair value of the principal amount of our debt as of December 31, 2020 and 2019, excluding pipeline financing obligations, was $70.0 million and $1,833.1 million, respectively, which decrease is primarily the result of the cancellation of $2.1 billion principal amount of debt as part of the Chapter 11 Restructuring. See Note 1, *Nature of Operations and Summary of Significant Accounting Policies – Emergence from Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code*, for additional information. We have other financial instruments consisting primarily of cash, cash equivalents, U.S. Treasury notes, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 14. Commitments and Contingencies

Commitments

We have entered into long-term commitments to purchase CO_2 that are either non-cancelable or cancelable only upon the occurrence of specified future events. The commitments continue for up to 8 years. The price we will pay for CO_2 generally varies depending on the amount of CO_2 delivered and the price of oil. Our annual commitment under these contracts could range from $15 million to $23 million per year, assuming a $60 per Bbl NYMEX oil price. In addition, we have a processing fee contract related to our overriding royalty interest in the CO_2 at LaBarge Field. We estimate our annual commitment under this contract could range from $8 million to $11 million per year based on current processing fee rates.

We are party to long-term contracts that require us to deliver CO_2 to our industrial CO_2 customers at various contracted prices. Based upon the maximum amounts deliverable as stated in the industrial contracts, we estimate that we may be obligated to deliver up to 673 Bcf of CO_2 to these customers over the next 14 years. The maximum volume required in any given year is approximately 276 MMcf/d, which we judge to be minor given the size of our Jackson Dome proved CO_2 reserves at December 31, 2020, our current production capabilities and our projected levels of CO_2 usage for our own tertiary flooding program.

Chapter 11 Proceedings

On July 30, 2020, Denbury Resources Inc. and each of its wholly-owned subsidiaries filed for relief under chapter 11 of the Bankruptcy Code. The chapter 11 cases were administered jointly under the caption "*In re Denbury Resources Inc., et al.*, Case No. 20-33801". On September 2, 2020, the Bankruptcy Court entered the Confirmation Order and on the Emergence Date, all of the conditions of the Plan were satisfied or waived and the Plan became effective and was implemented in accordance with its terms. On September 30, 2020, the Bankruptcy Court closed the chapter 11 cases of each of Denbury Inc.'s wholly-owned subsidiaries. The chapter 11 case captioned "*In re Denbury Resources Inc., et al.*, Case No. 20-33801" will remain pending until the final resolution of all outstanding claims.

Litigation

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position, results of operations or cash flows, litigation is subject to inherent uncertainties. We accrue for losses from litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

Riley Ridge Helium Supply Contract Claim

As part of our 2010 and 2011 acquisitions of the Riley Ridge Unit and associated gas processing facility that was under construction, the Company assumed a 20-year helium supply contract under which we agreed to supply the helium separated from the full well stream by operation of the gas processing facility to a third-party purchaser, APMTG Helium, LLC ("APMTG").

As the gas processing facility was shut-in during mid-2014 due to significant technical issues, we were not able to supply helium under the helium supply contract. In a case filed in November 2014 in the Ninth Judicial District Court of Sublette County, Wyoming, APMTG claimed multiple years of liquidated damages for non-delivery of volumes of helium specified under the helium supply contract. The Company claimed that its contractual obligations were excused by virtue of events that fall within the force majeure provisions in the helium supply contract.

On March 11, 2019, the trial court entered a final judgment that a force majeure condition did exist, but such condition only excused the Company's performance for a 35-day period in 2014, and as a result the Company should pay APMTG liquidated damages and interest thereon for all other time periods for performance from contract commencement to the close of evidence (November 29, 2017). On December 4, 2020, the Wyoming Supreme Court entered a judgment affirming the trial court's ruling on all counts and, as a result, the Company paid total liquidated damages (including interest) of $52.1 million to APMTG on December 23, 2020 in full satisfaction of all claims. The Company had previously recorded an accrual for these costs in "Accounts payable and accrued liabilities" in our Consolidated Balance Sheets.

Other Contingencies

We are subject to audits for various taxes (income, sales and use, and severance) in the various states in which we operate, and from time to time receive assessments for potential taxes that we may owe. In the past, settlement of these matters has not had a material adverse financial impact on us, and currently we have no material assessments for potential taxes.

We are subject to various possible contingencies that arise primarily from interpretation of federal and state laws and regulations affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Although we believe that we have complied with the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued. In addition, production rates, marketing and environmental matters are subject to regulation by various federal and state agencies.

Note 15. Additional Balance Sheet Details

Rollforward of Allowance for Doubtful Accounts

	Successor	Predecessor		
	Period from Sept. 19, 2020 through	Period from Jan. 1, 2020 through	Year Ended	
In thousands	Dec. 31, 2020	Sept. 18, 2020	Dec. 31, 2019	Dec. 31, 2018
Beginning balance	$ 22,146	$ 17,137	$ 17,070	$ 229
Provision for doubtful accounts	1,060	5,297	68	16,911
Write-offs	—	(288)	(1)	(70)
Ending balance	$ 23,206	$ 22,146	$ 17,137	$ 17,070

Accounts Payable and Accrued Liabilities

	Successor	Predecessor
In thousands	December 31, 2020	December 31, 2019
Accrued general and administrative expenses	$ 21,825	$ 21,838
Accrued lease operating expenses	21,294	26,686
Accounts payable	18,629	29,077
Taxes payable	17,221	21,274
Accrued compensation	7,512	36,366
Accrued exploration and development costs	1,861	7,811
Accrued interest	1,833	25,253
Other	22,496	15,527
Total	$ 112,671	$ 183,832

Note 16. Supplemental Cash Flow Information

Supplemental Cash Flow Information

	Successor	Predecessor		
In thousands	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	Year Ended December 31, 2019	Year Ended December 31, 2018
Supplemental cash flow information				
Cash paid for interest, expensed	$ 813	$ 29,357	$ 72,842	$ 50,076
Cash paid for interest, capitalized	1,261	22,885	36,671	37,079
Cash paid for interest, treated as a reduction of debt	—	46,417	85,303	79,606
Cash paid for income taxes	—	453	2,361	492
Cash received from income tax refunds	10,457	1,932	9,820	8,280
Noncash investing and financing activities				
Increase in asset retirement obligations	23,398	4,328	13,560	4,499
Increase (decrease) in liabilities for capital expenditures	1,867	(12,809)	(17,740)	14,600
Conversion of convertible senior notes into common stock	—	11,501	—	162,004

Note 17. Subsequent Event

On March 3, 2021, we closed on an agreement to acquire working interest positions in the Big Sand Draw and Beaver Creek oil fields located in Wyoming, including surface facilities and a CO_2 transportation pipeline to the acquired fields, for a cash purchase price of $12 million before closing adjustments.

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES (UNAUDITED)

Costs Incurred

The following table summarizes costs incurred and capitalized in oil and natural gas property acquisition, exploration and development activities. Property acquisition costs are those costs incurred to purchase, lease or otherwise acquire property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs, and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling development wells, and to provide facilities for extracting, treating, gathering and storing the oil and natural gas, and the cost of improved recovery systems.

We capitalize interest on unevaluated oil and natural gas properties that have ongoing development activities. Included in costs incurred in the table below is capitalized interest of $1.2 million for the period September 19, 2020 through December 31, 2020 (Successor), $22.0 million for the period January 1, 2020 through September 18, 2020 (Predecessor), and $34.1 million and $36.5 million during the years ended December 31, 2019 and 2018, respectively. Costs incurred also include new asset retirement obligations established, as well as changes to asset retirement obligations resulting from revisions in cost estimates or abandonment dates. Asset retirement obligations included in the table below were $3.4 million for the period September 19, 2020 through December 31, 2020 (Successor), $2.5 million for the period January 1, 2020 through September 18, 2020 (Predecessor), and $15.2 million and $6.8 million during the years ended December 31, 2019 and 2018, respectively. See Note 6, *Asset Retirement Obligations*, for additional information.

Costs incurred in oil and natural gas activities were as follows:

	Successor	Predecessor		
	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	Year Ended December 31,	
In thousands			2019	2018
Property acquisitions				
Proved	$ 130	$ 278	$ 1,542	$ 2,030
Unevaluated	—	—	—	—
Exploration	60	260	2,575	1,030
Development	23,741	92,212	259,641	338,203
Total costs incurred(1)	$ 23,931	$ 92,750	$ 263,758	$ 341,263

(1) Capitalized general and administrative costs that directly relate to exploration and development activities were $5.6 million for the period September 19, 2020 through December 31, 2020 (Successor), $19.5 million for the period January 1, 2020 through September 18, 2020 (Predecessor), and $39.5 million and $37.2 million for the years ended December 31, 2019 and 2018, respectively.

Oil and Natural Gas Operating Results

Results of operations from oil and natural gas producing activities, excluding corporate overhead and interest costs, were as follows:

	Successor	Predecessor		
	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020	Year Ended December 31,	
In thousands, except per-BOE data			2019	2018
Oil, natural gas, and related product sales	$ 201,108	$ 492,101	$ 1,212,020	$ 1,422,589
Lease operating expenses	101,234	250,271	477,220	489,720
Transportation and marketing expenses	10,595	27,164	41,810	43,942
Production and ad valorem taxes	15,061	38,647	86,820	96,589
Depletion, depreciation, and amortization	37,549	104,504	161,400	144,423
CO_2 properties and pipelines depletion and depreciation[1]	1,744	33,839	53,120	48,792
Write-down of oil and natural gas properties	1,006	996,658	—	—
Commodity derivatives expense (income)	61,902	(102,032)	70,078	(21,087)
Net operating income (loss)	(27,983)	(856,950)	321,572	620,210
Income tax provision (benefit)	—	(214,238)	80,393	155,053
Results of operations from oil and natural gas producing activities	$ (27,983)	$ (642,712)	$ 241,179	$ 465,157
Depletion, depreciation, and amortization per BOE	$ 7.72	$ 10.15	$ 10.10	$ 8.77

(1) Represents an allocation of the depletion and depreciation of our CO_2 properties and pipelines associated with our tertiary oil producing activities.

Oil and Natural Gas Reserves

Net proved oil and natural gas reserve estimates for all years presented were prepared by DeGolyer and MacNaughton, independent petroleum engineers located in Dallas, Texas. These oil and natural gas reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. See *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves* below for a discussion of the effect of the different prices on reserve quantities and values. Operating costs, production and ad valorem taxes, and future development costs were based on current costs as of December 31, 2020.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present values should not be construed as the current market value of our oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. Estimates of reserves as of year-end 2020, 2019 and 2018 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the applicable fiscal 12-month period. All of our reserves are located in the United States.

Estimated Quantities of Proved Reserves

	Year Ended December 31,								
	2020			2019			2018		
	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)
Balance at beginning of year	226,133	24,334	230,189	255,042	43,008	262,210	252,625	42,721	259,745
Revisions of previous estimates	(63,359)	(5,822)	(64,329)	(6,799)	(15,299)	(9,348)	21,658	6,115	22,677
Improved recovery[1]	—	—	—	977	—	977	2,314	(157)	2,288
Production	(18,237)	(2,905)	(18,721)	(20,685)	(3,375)	(21,248)	(21,364)	(3,962)	(22,024)
Sales of minerals in place	(4,038)	(3)	(4,039)	(2,402)	—	(2,402)	(191)	(1,709)	(476)
Balance at end of year	140,499	15,604	143,100	226,133	24,334	230,189	255,042	43,008	262,210
Proved Developed Reserves – end of year	136,402	15,604	139,003	202,816	24,333	206,872	222,736	42,912	229,888
Proved Undeveloped Reserves – end of year	4,097	—	4,097	23,317	1	23,317	32,306	96	32,322

(1) Improved recovery reflects reserve additions that result from the application of secondary recovery methods such as water flooding or tertiary recovery methods such as CO_2 flooding. In order to recognize proved tertiary oil reserves, we must either have an oil production response to CO_2 injections or the field must be analogous to an existing tertiary flood. The magnitude of proved reserves that we can book in any given year will depend on our progress with new floods and the timing of the production response.

Revisions of previous estimates during 2020, 2019, and 2018 primarily reflect changes in commodity prices between December 31, 2017 and 2020.

There were no significant additions to our oil and natural gas reserves, as the magnitude of proved reserves that we can book in any given year depends on our progress with new floods and the timing of the production response, and we initiated no new floods in 2020, 2019 or 2018.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves

The Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves ("Standardized Measure") does not purport to present the fair market value of our oil and natural gas properties. An estimate of such value should consider, among other factors, anticipated future prices of oil and natural gas, the probability of recoveries in excess of existing proved reserves, the value of probable reserves and acreage prospects, and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revision.

Under the Standardized Measure, future cash inflows were estimated by applying a first-day-of-the-month 12-month average price to the estimated future production of year-end proved reserves. These prices have a significant impact on both the quantities and value of the proved reserves, as reductions in oil and natural gas prices can cause wells to reach the end of their economic life much sooner and can make certain proved undeveloped locations uneconomical, both of which reduce the reserves. The following representative oil and natural gas prices were used in the Standardized Measure. These prices were adjusted by field to arrive at the appropriate corporate net price.

	December 31,		
	2020	2019	2018
Oil (NYMEX price per Bbl)	$ 39.57	$ 55.69	$ 65.56
Natural Gas (Henry Hub price per MMBtu)	1.99	2.58	3.10

The changes in the Standardized Measure of discounted future net cash flows in the tables that follow were significantly impacted by the movement in first-day-of-the-month average NYMEX oil prices between 2018 and 2020. The weighted-average oil prices we receive relative to NYMEX oil prices (our NYMEX oil price differential) utilized were \$3.73 per Bbl below representative NYMEX oil prices as of December 31, 2020, compared to \$0.14 per Bbl below representative NYMEX oil prices as of December 31, 2019, and \$0.24 per Bbl below representative NYMEX oil prices as of December 31, 2018.

Future cash inflows were reduced by estimated future production, development and abandonment costs based on current cost, with no escalation to determine pre-tax cash inflows. Our future net inflows do not include a reduction for cash previously expended on our capitalized CO_2 assets that will be consumed in the production of proved tertiary reserves. Future income taxes were computed by applying the statutory tax rate to the excess of net cash inflows over our tax basis in the associated proved oil and natural gas properties. Tax credits and net operating loss carryforwards were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

	December 31,		
In thousands	2020	2019	2018
Future cash inflows	\$ 5,010,288	\$ 12,494,358	\$ 16,657,988
Future production costs	(3,300,890)	(6,813,610)	(8,000,884)
Future development costs	(962,224)	(1,434,934)	(1,524,476)
Future income taxes	(59,600)	(586,441)	(1,186,769)
Future net cash flows	687,574	3,659,373	5,945,859
10% annual discount for estimated timing of cash flows	(32,840)	(1,398,334)	(2,594,474)
Standardized measure of discounted future net cash flows	\$ 654,734	\$ 2,261,039	\$ 3,351,385

The following table sets forth an analysis of changes in the Standardized Measure of Discounted Future Net Cash Flows from proved oil and natural gas reserves:

	Year Ended December 31,		
In thousands	2020	2019	2018
Beginning of year	\$ 2,261,039	\$ 3,351,385	\$ 2,232,429
Sales of oil and natural gas produced, net of production costs	(250,237)	(608,060)	(797,132)
Net changes in prices and production costs	(1,753,248)	(1,244,859)	1,963,333
Improved recovery(1)	—	5,785	11,536
Previously estimated development costs incurred	28,182	81,024	109,214
Change in future development costs	11,200	(35,624)	(42,240)
Revisions due to timing and other	(127,046)	41,841	10,915
Accretion of discount	233,663	367,313	234,434
Sales of minerals in place	(55,102)	(16,892)	1,281
Net change in income taxes	306,283	319,126	(372,385)
End of year	\$ 654,734	\$ 2,261,039	\$ 3,351,385

(1) Improved recovery additions result from the application of secondary recovery methods such as water flooding or tertiary recovery methods such as CO_2 flooding.

SUPPLEMENTAL CO_2 DISCLOSURES (UNAUDITED)

Based on engineering reports prepared by DeGolyer and MacNaughton, proved CO_2 reserves were estimated as follows:

	Year Ended December 31,		
In MMcf	2020	2019	2018
CO_2 reserves			
Gulf Coast region(1)	4,641,812	4,786,881	4,982,440
Rocky Mountain region(2)	1,089,101	1,120,060	1,155,538

(1) Proved CO_2 reserves in the Gulf Coast region consist of reserves from our reservoirs at Jackson Dome and are presented on a gross (8/8ths) basis, of which our net revenue interest was approximately 3.7 Tcf, 3.8 Tcf and 4.0 Tcf at December 31, 2020, 2019 and 2018, respectively, and include reserves dedicated to volumetric production payments of 3.1 Bcf at December 31, 2018.

(2) Proved CO_2 reserves in the Rocky Mountain region consist of our overriding royalty interest in LaBarge Field, of which our net revenue interest was approximately 1.1 Tcf, 1.1 Tcf and 1.2 Tcf at December 31, 2020, 2019 and 2018, respectively.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2020, to ensure that information that is required to be disclosed in the reports the Company files and submits under the Securities Exchange Act of 1934 is recorded; that it is processed, summarized and reported within the time periods specified in the SEC's rules and forms; and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Evaluation of Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we have determined that, during the fourth quarter of fiscal 2020, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of the end of the period covered by this report based on the framework in "Internal Control – Integrated Framework" (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, our Chief Executive Officer and our Chief Financial Officer concluded that our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

The effectiveness of our internal control over financial reporting as of December 31, 2020, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in the report that appears herein.

Important Considerations

The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to various inherent limitations, including cost limitations, judgments used in decision making, assumptions about the likelihood of future events, the soundness of our systems, the possibility of human error, and the risk of fraud. Moreover, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions and the risk that the degree of compliance with policies or procedures may deteriorate over time. Because of these limitations, there can be no assurance that any system of disclosure controls and procedures or internal control over financial reporting will be successful in preventing all errors or fraud or in making all material information known in a timely manner to the appropriate levels of management.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Except as disclosed below, information as to Item 10 will be set forth in the Proxy Statement ("Proxy Statement") for the 2021 Annual Meeting of Shareholders to be held May 26, 2021 ("Annual Meeting") and is incorporated herein by reference.

Code of Ethics

We have adopted a Code of Ethics for Senior Financial Officers. This Code of Ethics, including any amendments or waivers, is posted on our website at www.denbury.com.

Item 11. Executive Compensation

Information as to Item 11 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

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

Information as to Item 12 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information as to Item 13 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information as to Item 14 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Denbury Inc.

PART IV

Item 15. Exhibits and Financial Statement Schedules

Financial Statements and Schedules. Financial statements and schedules filed as a part of this report are presented on page 70. All financial statement schedules have been omitted because they are not applicable, or the required information is presented in the financial statements or the notes to consolidated financial statements.

Exhibits. The following exhibits are included as part of this report.

Exhibit No.	Exhibit
2(a)	Joint Chapter 11 Plan of Reorganization of Denbury Resources Inc. and its Debtor Affiliates (Technical Modifications) (incorporated by reference to Exhibit A of the Order Approving the Debtors' Disclosure Statement For, and Confirming, the Debtors' Joint Chapter 11 Plan of Reorganization of Denbury Resources Inc. and its Debtor Affiliates, filed as Exhibit 2.1 to Form 8-K filed by the Company on September 4, 2020, File No. 001-12935).
3(a)	Third Restated Certificate of Incorporation of Denbury Resources Inc. (incorporated by reference to Exhibit 3.1 of Form 8-K filed by the Company on September 18, 2020, File No. 001-12935).
3(b)	Fourth Amended and Restated Bylaws of Denbury Resources Inc., as of September 18, 2020 (incorporated by reference to Exhibit 3.2 of Form 8-K filed by the Company on September 18, 2020, File No. 001-12935).
4(a)	Series A Warrant Agreement, dated as of September 18, 2020, by and between Denbury Inc., and Broadridge Corporate Issuer Solutions, Inc. (incorporated by reference to Exhibit 10.2 of Form 8-K filed by the Company on September 18, 2020, File No. 001-12935).
4(b)	Series B Warrant Agreement, dated as of September 18, 2020, by and between Denbury Inc., and Broadridge Corporate Issuer Solutions, Inc. (incorporated by reference to Exhibit 10.3 of Form 8-K filed by the Company on September 18, 2020, File No. 001-12935).
4(c)	Registration Rights Agreement, dated as of September 18, 2020, among Denbury Inc. and certain holders identified therein (incorporated by reference to Exhibit 10.4 of Form 8-K filed by the Company on September 18, 2020, File No. 001-12935).
10(a)	Credit Agreement, dated as of September 18, 2020, by and among Denbury Inc., as borrower, the lenders party thereto, and JPMorgan Chase Bank, N.A., as administrative agent, swingline lender, and letter of credit issuer (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on September 18, 2020, File No. 001-12935).
10(b) **	Form of Indemnification Agreement, by and between Denbury Inc. and its officers and directors (incorporated by reference to Exhibit 10.5 of Form 8-K filed by the Company on September 18, 2020, File No. 001-12935).
10(c)	Restructuring Support Agreement, dated July 28, 2020 (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on July 29, 2020, File No. 001-12935).
10(d) **	2020 Form of Incentive Bonus Agreement for Denbury Resources Inc. (incorporated by reference to Exhibit 10(g) of Form 10-Q filed by the Company on August 11, 2020, File No. 001-12935).
10(e) **	Denbury Inc. 2020 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on December 4, 2020, File No. 001-12935).
10(f) * **	2020 Form of Restricted Stock Unit Award under the 2020 Omnibus Stock and Incentive Plan for Denbury Inc.

Exhibit No.	Exhibit
10(g) * **	2020 Form of Director Deferred Stock Unit Award under the 2020 Omnibus Stock and Incentive Plan for Denbury Inc.
10(h) * **	2020 Form of Performance Stock Unit Award under the 2020 Omnibus Stock and Incentive Plan for Denbury Inc.
21*	List of subsidiaries of Denbury Inc.
23(a)*	Consent of PricewaterhouseCoopers LLP.
23(b)*	Consent of PricewaterhouseCoopers LLP.
23(c)*	Consent of DeGolyer and MacNaughton.
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99*	The summary of DeGolyer and MacNaughton's Report as of December 31, 2020, on oil and gas reserves (SEC Case) dated February 5, 2021.
101.INS*	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Document Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

* Included herewith.
** Compensation arrangements.

Item 16. Form 10-K Summary

None.

Denbury Inc.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Denbury Inc. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	DENBURY INC.
March 5, 2021	/s/ Mark C. Allen
	Mark C. Allen Executive Vice President and Chief Financial Officer
March 5, 2021	/s/ Nicole Jennings
	Nicole Jennings Vice President and Chief Accounting 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 Denbury Inc. and in the capacities and on the dates indicated.

March 5, 2021	/s/ Christian S. Kendall
	Christian S. Kendall Director, President and Chief Executive Officer (Principal Executive Officer)
March 5, 2021	/s/ Mark C. Allen
	Mark C. Allen Executive Vice President and Chief Financial Officer (Principal Financial Officer)
March 5, 2021	/s/ Nicole Jennings
	Nicole Jennings Vice President and Chief Accounting Officer (Principal Accounting Officer)
March 5, 2021	/s/ Kevin O. Meyers
	Kevin O. Meyers Director
March 5, 2021	/s/ Anthony Abate
	Anthony Abate Director
March 5, 2021	/s/ Caroline Angoorly
	Caroline Angoorly Director
March 5, 2021	/s/ James Chapman
	James Chapman Director

March 5, 2021	/s/ Lynn A. Peterson
	Lynn A. Peterson Director
March 5, 2021	/s/ Brett Wiggs
	Brett Wiggs Director

Exhibit 21

LIST OF SUBSIDIARIES

Name of Subsidiary	Jurisdiction of Organization
Denbury Operating Company	Delaware
Denbury Onshore, LLC	Delaware
Denbury Pipeline Holdings, LLC	Delaware
Denbury Holdings, Inc.	Delaware
Denbury Green Pipeline – Texas, LLC	Delaware
Greencore Pipeline Company, LLC	Delaware
Denbury Gulf Coast Pipelines, LLC	Delaware

Exhibit 23(a)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (No. 333-251121) of Denbury Inc. of our report dated March 5, 2021 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Dallas, Texas
March 5, 2021

Exhibit 23(b)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (No. 333-251121) of Denbury Resources Inc. of our report dated March 5, 2021 relating to the financial statements, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Dallas, Texas
March 5, 2021

Exhibit 23(c)

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

March 1, 2021

Denbury Inc.
5851 Legacy Circle
Plano, Texas 75024

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton, to the inclusion of our report of third party dated February 5, 2021, regarding the proved reserves of Denbury Inc., and to the inclusion of information taken from our reports entitled "Report as of December 31, 2020 on Reserves and Revenue of Certain Properties with interests attributable to Denbury Inc.," "Report as of December 31, 2019 on Reserves and Revenue of Certain Properties with interests attributable to Denbury Resources Inc.," and "Report as of December 31, 2018 on Reserves and Revenue of Certain Properties with interests attributable to Denbury Resources Inc. SEC Case" in the Annual Report on Form 10-K of Denbury Inc. for the year ended December 31, 2020.

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

Exhibit 31(a)

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Christian S. Kendall, certify that:

1. I have reviewed this report on Form 10-K of Denbury Inc. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 5, 2021

/s/ Christian S. Kendall

Christian S. Kendall

Director, President and Chief Executive Officer

Exhibit 31(b)

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark C. Allen, certify that:

1. I have reviewed this report on Form 10-K of Denbury Inc. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 5, 2021

/s/ Mark C. Allen

Mark C. Allen

Executive Vice President, Chief Financial Officer,
Treasurer, and Assistant Secretary

Exhibit 32

Certification of Chief Executive Officer and Chief Financial Officer
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the accompanying Annual Report on Form 10-K for the year ended December 31, 2020 (the Report) of Denbury Inc. (Denbury) as filed with the Securities and Exchange Commission, each of the undersigned, in his capacity as an officer of Denbury, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Denbury.

Dated: March 5, 2021

/s/ Christian S. Kendall

Christian S. Kendall
Director, President and Chief Executive Officer

Dated: March 5, 2021

/s/ Mark C. Allen

Mark C. Allen
Executive Vice President, Chief Financial Officer, Treasurer, and Assistant Secretary

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CORPORATE INFORMATION

BOARD OF DIRECTORS

Kevin O. Meyers
Chairman of the Board
Independent Consultant

Anthony M. Abate
Founder, Chief Operating Officer and Chief Financial Officer
Echo360, Inc.

Caroline G. Angoorly
Managing Partner
GreenTao LLC

James N. Chapman
Independent Consultant

Christian S. Kendall
President and Chief Executive Officer
Denbury Inc.

Lynn A. Peterson
Chief Executive Officer and President
Whiting Petroleum Corporation

Brett R. Wiggs
Chief Executive Officer
Oryx Midstream Services

Cindy A. Yeilding
Independent Consultant

CONTACTING BOARD MEMBERS

You may contact our board members by addressing a letter to Denbury Inc., Attn: Corporate Secretary, or by email to secretary@denbury.com

EXECUTIVE OFFICERS

Christian S. Kendall
President and Chief Executive Officer

Mark Allen
Executive Vice President, Chief Financial Officer, Treasurer and Assistant Secretary

Jim Matthews
Executive Vice President, Chief Administrative Officer, General Counsel and Secretary

STOCK EXCHANGE LISTING

New York Stock Exchange ("NYSE")
Ticker Symbol: DEN

CORPORATE HEADQUARTERS

Denbury Inc.
5851 Legacy Circle, Suite 1200
Plano, Texas 75024
972. 673. 2000
www.denbury.com

STOCK TRANSFER AGENT & REGISTRAR

For questions concerning dividends, stock certificates, transfer procedures or address changes, please contact:

Broadridge Corporate Issuer Solutions
P.O. Box 1342, Brentwood, NY 11717
866.804.4482
Email: shareholder@broadridge.com
www.shareholder.broadridge.com/bcis

INVESTOR INQUIRIES

Investor Relations
972. 673. 2000
Email: ir@denbury.com

ANNUAL CERTIFICATIONS

During 2020, our Chief Executive Officer certified to the NYSE that he is not aware of any violation by the Company of the NYSE's corporate governance listing standards.

FINANCIAL INFORMATION REQUESTS

For additional information and to receive additional copies of the Annual Report on Form 10-K as filed with the Securities and Exchange Commission ("SEC") or to obtain other Denbury public documents, please contact:

Denbury Inc.
Investor Relations
5851 Legacy Circle, Suite 1200
Plano, Texas 75024
972.673.2000
Email: ir@denbury.com

Our Form 10-K filed with the SEC is included herein, excluding all exhibits other than our Section 302, 404 and 906 certifications by the CEO and CFO. We will send shareholders our Form 10-K exhibits and any of our corporate governance documents, without charge, upon request. These documents are also available on our website at www.denbury.com.

ANNUAL MEETING

The Annual Meeting of Stockholders will be held virtually at www.virtualshareholdermeeting.com/DEN2021 (1-800-586-1548 for questions) at 8:00 A.M. CDT on Wednesday, May 26, 2021.

LEGAL COUNSEL

Baker & Hostetler LLP

BANKERS

J.P. Morgan (Agent)

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

PricewaterhouseCoopers LLP

RESERVE ENGINEERS

DeGolyer and MacNaughton

DEN LISTED NYSE

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5851 Legacy Circle, Suite 1200
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