Denbury

2022 Annual Report

Carbon Solutions for a Sustainable Future

FORWARD-LOOKING STATEMENT

This Annual Report contains forward-looking statements regarding the Company's current expectations and estimates, in addition to the forward-looking statements discussed under "Forward-Looking Information" at the end of the Management's Discussion and Analysis section of the Form 10-K for the year 2022 contained in this Annual Report. These statements are subject to a variety of risks and uncertainties that could cause the Company's actual results to differ materially from these expectations and estimates.

The world needs clean energy.

Abundant energy is essential to our economy, our security, and our way of life, but the same energy that powers our world also produces carbon dioxide (“CO_2”) emissions that contribute to climate change. Around the world, corporations are seeking innovative ways to reduce their carbon footprint while continuing to provide the resources we depend on, and Denbury is delivering decarbonization solutions that enable and support these efforts.

As a leader in Carbon Capture, Utilization, and Storage (“CCUS”), we utilize industrial-sourced CO_2 to produce environmentally friendly, carbon-negative “Blue Oil” through Enhanced Oil Recovery (“EOR”). With the largest CO_2 pipeline network in the U.S. and a growing portfolio of dedicated sequestration sites, we are also poised to provide safe, permanent underground CO_2 sequestration in the near future. At Denbury, we are uniquely positioned to responsibly meet the world’s energy needs while reducing global CO_2 emissions, ensuring that the ideas and technologies that power our lives today also contribute to a more sustainable future.

Dear Fellow Shareholders,

On behalf of the Board of Directors and our employees, thank you for your investment in Denbury.

Denbury is in an amazing position to continue delivering our mission, *Carbon Solutions for a Sustainable Future*, as we enter 2023. The world's need for secure sources of energy of all types continues to grow, and the past several years of underinvestment in global oil production have begun to put stress on the industry's ability to supply the world's recovering oil demand. In addition, U.S. policy support for carbon capture, utilization, and storage ("CCUS") has never been greater, and we are just scratching the surface of the scale we expect to see in CCUS. The combination of the Section 45Q CCUS tax incentive and significant improvements in carbon capture technology is opening the door for a vast portion of current and future U.S. emissions to be captured economically.

Considering that backdrop, Denbury is uniquely situated to capitalize on the rapidly growing demand for CCUS solutions and play an important part in meaningfully reducing carbon emissions, while also providing a valuable, essential low-carbon energy source. As we continue to make progress toward our vision *to power the energy transition with world-leading carbon solutions*, our extensive CO_2 infrastructure and expertise put us in the center of the exciting, high-growth CCUS story, and we are just in the first chapter.

Our long-lived CO_2 Enhanced Oil Recovery ("EOR") focused business is providing an increasing proportion of carbon-negative "Blue Oil", and our multi-year development of the massive Cedar Creek Anticline ("CCA") EOR resource will reach a key milestone with initial EOR production this year, the first of many decades of significant production from this great asset.

We have the most expansive CO_2 pipeline network in the United States, and I believe the deepest talent base of experts with passion and knowledge around all aspects of CO_2 management. This combination has positioned Denbury to be a leader in both EOR and CCUS for decades into the future.

Safety is core to our operational performance, and in 2022, we achieved a Total Recordable Incident Rate of 0.53, our second-lowest rate in the Company's history. This occurred in a year of high operational activity across our Gulf Coast and Rocky Mountain operations, and I want to thank all of our teams for maintaining their focus on safety in everything we do.

Denbury's 2022 financial results reflect robust oil prices and the underlying strength of our operations. For the full year, we generated operating cash flow significantly above our combined oil & gas and CCUS capital expenditures. We returned 75% of our free cash flow to our shareholders by repurchasing $100 million of our shares, or approximately 3% of our outstanding stock. While investing in long-term growth opportunities in both the oil and CCUS businesses and returning capital to shareholders, we exited the year with very low levels of debt and significant financial liquidity. Our financial strength positions us well to execute on the transformational growth in front of us.

0.53 TRIR

Second lowest total recordable incident rate in Denbury history

-2.5 M Metric Tons

Scope 1 and 2 net negative CO_2e emissions for 2022

40% Industrial CO_2

Injected in EOR operations, resulting in carbon-negative or "Blue Oil"

$100 Million

Capital returned to shareholders through share repurchases in 2022

Our extensive use of industrial sourced CO_2 in our operations, which increased to 4.3 million metric tons in 2022, helped the Company once again achieve net negative Scope 1 and 2 emissions for the year. In 2022, we began CO_2 injection at the CCA EOR project, the largest potential CO_2 EOR resource that we have ever developed, with ultimate recovery more than twice the size of our year-end 2022 proved reserves. CO_2 injection into Phase 1 of the development totaled 1.4 million metric tons at the end of the year, and we began installing the necessary CO_2 recycling facilities to position ourselves for a second-half 2023 production start-up. Development of this project will greatly enhance the strength and sustainability of our EOR business. Importantly, this production is 100% carbon-negative oil, which we believe will become a highly desired commodity in the future.

Our CCUS business delivered exceptional results in 2022 as we expanded our first-mover advantage in this emerging industry. During the year, we signed agreements with industrial customers covering more than 18 million metric tons per year of CO_2. Compared to today's global CO_2 capture of slightly more than 40 million metric tons per year, we are making a significant impact on the global emissions reductions needed to deliver a sustainable future. The largest of these new agreements was with a newbuild blue ammonia project to be constructed in Donaldsonville, Louisiana, and we elected to participate as an equity owner, providing even more upside for our shareholders to the entire CCUS value chain.

In addition, we expanded our dedicated CO_2 storage portfolio to more than 2 billion tons with new sequestration site agreements, all in close proximity to our existing pipeline network, which will allow us to provide the industry's most efficient and reliable CO_2 takeaway solution. Near the end of the year, we submitted our initial Class VI injection permits to the EPA, which were deemed technically complete earlier this year.

Our priorities for 2023 build on these 2022 successes. At CCA, we're preparing for production from our largest-ever EOR development to begin in just a few months, and we're also investing in multiple high return oil-focused projects across our portfolio. Capital allocation to our CCUS business has more than doubled this year, in line with our plans to rapidly grow that business by acquiring additional dedicated storage sites and beginning the process to expand our pipeline network reach to industrial customers. I am more confident than ever that Denbury has the right strategy, the right people, and the right assets to deliver transformational growth for our shareholders.

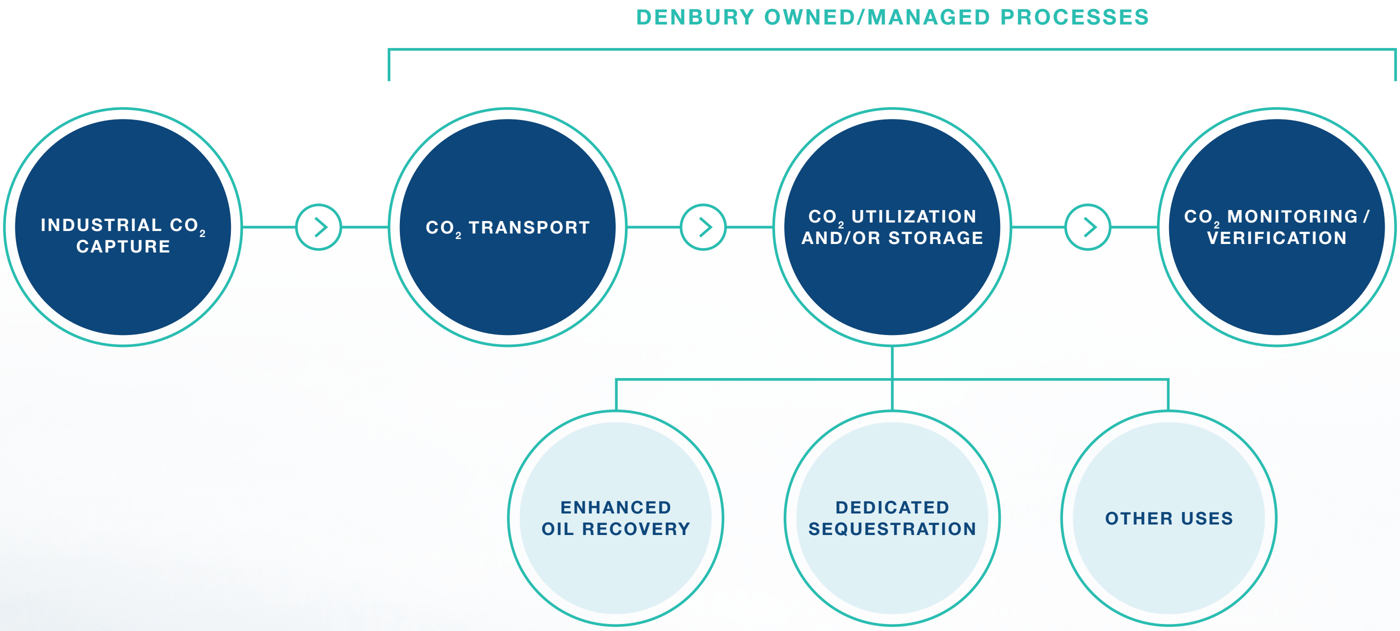
Sincerely,

Chris Kendall
President & Chief Executive Officer

> "As we continue to make progress towards our vision *to power the energy transition with world-leading carbon solutions*, our extensive CO_2 infrastructure and expertise put us in the center of the exciting, high-growth CCUS story, and we are just in the first chapter.

Carbon Capture, Utilization, and Storage

Carbon Capture, Utilization, and Storage ("CCUS") is the process of capturing industrial-sourced CO_2 before it is released into the atmosphere, and either storing it permanently, or using it to create valuable products or services. Enhanced Oil Recovery ("EOR") and carbon sequestration are both CCUS solutions.



CCUS, through both CO_2 EOR and direct underground sequestration, utilizes proven technology with the potential for safe, long-term, deep underground containment of billions of tons of industrial-sourced CO_2. CCUS has the potential to drive a substantial reduction in atmospheric CO_2 emissions, and when utilizing industrial-sourced CO_2, we estimate the oil produced in EOR is Scope 1, 2, & 3 negative, making it the most environmentally-beneficial oil on the planet.

CO_2 SOURCES

Denbury sources CO_2 from naturally-occurring underground reservoirs and from industrial sources that capture, process, and compress the CO_2 for delivery into our pipeline network. The CO_2 captured from industrial sources would otherwise be released into the atmosphere. Over the next several years, Denbury plans to significantly increase its supply of industrial CO_2 while reducing naturally-occurring CO_2 used in its EOR operations.

CO_2 TRANSPORTATION

We own and operate the most expansive CO_2 pipeline infrastructure in the U.S., including over 1,300 miles of CO_2 pipelines in the Gulf Coast and Rocky Mountains. Our pipeline network currently transports millions of metric tons of CO_2 per year in supercritical phase across our infrastructure. We are continually expanding our pipeline network to transport CO_2 for use in our operations, and we are developing plans to connect dedicated sequestration sites to our infrastructure.

CO_2 STORAGE

Captured CO_2 is safely contained underground through EOR, whereby the injected CO_2 moves through the reservoir, displacing crude oil which is produced. In addition to EOR, Denbury is building a portfolio of multiple dedicated sequestration sites along the U.S. Gulf Coast and in the Rocky Mountains with plans to inject CO_2 securely underground for long-term containment in reservoirs not associated with EOR.

ENHANCED OIL RECOVERY (EOR)

With more than 20 years of EOR experience, Denbury is an industry leader in carbon-dioxide injection to increase oil recovery and oil production. When utilizing CO_2 captured from industrial sources, we more than offset Scope 1, 2, and 3 emissions for each barrel of oil by injecting and storing CO_2 underground, resulting in carbon-negative or "Blue Oil".

$521 Million

2022 cash flows from operations, up 64% from 2021

46.8 MBoe/d

2022 sales volumes (28% carbon-negative)

13.4 M Metric Tons

2022 total CO_2 sourced and transported (~32% industrial)

202 MMBoe

YE22 oil & gas proved reserves, an increase of 5% over 2021

CARBON SEQUESTRATION

Denbury is actively working to develop a portfolio of dedicated CO_2 sequestration sites in the Rocky Mountains and along the U.S. Gulf Coast in close proximity to the Company's existing carbon pipeline network. We are planning to provide to customers safe, permanent underground storage of CO_2 emissions through the industry's most reliable and efficient carbon storage network.

22 MMTPA

Total CO_2 volume under future transport and/or storage agreements

>2 B Metric Tons

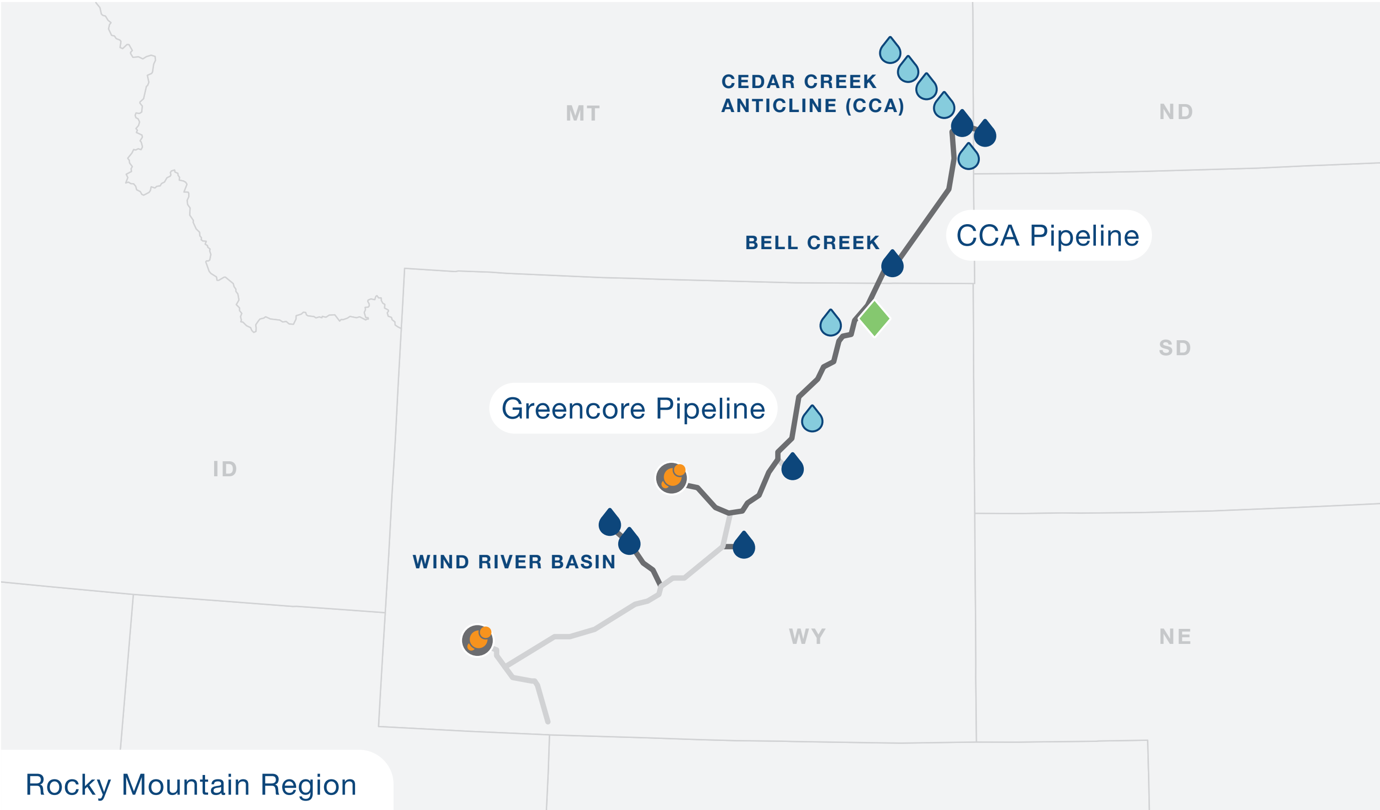
Secured sequestration capacity across the company's 8 dedicated CO_2 storage sites

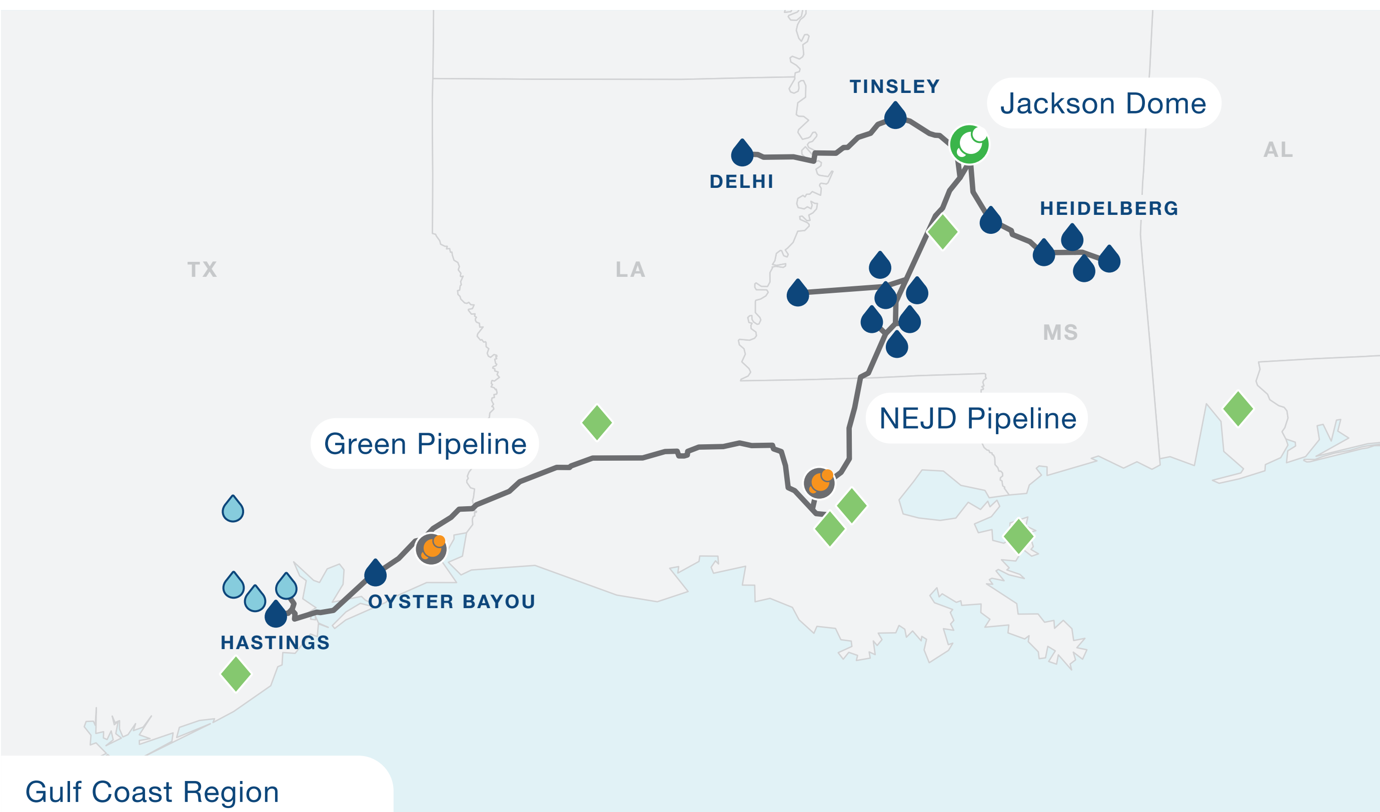
1,300+ Miles

Largest owned and operated CO_2 pipeline network in the U.S.

3 Class VI Permits

Submitted initial class VI permits for dedicated CO_2 injection in 2022





Enhanced oil recovery field
Non-EOR field
Naturally occurring CO_2 source
Industrial CO_2 source
Denbury planned CO_2 storage site
Denbury-owned CO_2 pipelines
CO_2 pipelines owned by others

Form 10-K

Denbury Inc.
2022 Annual Report

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

2022 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, 2022
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. ☑

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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 $3,048,881,728.

The number of shares outstanding of the registrant's Common Stock as of January 31, 2023, was 49,839,666.

DOCUMENTS INCORPORATED BY REFERENCE

Document:	**Incorporated as to:**
1. Notice and Proxy Statement for the Annual Meeting of Stockholders to be held June 1, 2023.	1. Part III, Items 10, 11, 12, 13, 14

Denbury Inc.

2022 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, Utilization, and Storage.
CO_2	Carbon dioxide.
CO_2e	The number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas.
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.
GHG	Greenhouse gas, which consists of those gases that trap heat in the atmosphere including CO_2, methane, nitrous oxide and fluorinated gases.
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.
Mmtpa	One million metric tons per year, typically used as a measure of CO_2 or other GHG emissions.
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.
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*	Proved 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*	Proved 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.

Denbury Inc.

PART I

Item 1. Business and Properties

GENERAL

Denbury Inc., a Delaware corporation, is an independent energy company with operations focused in the Gulf Coast and Rocky Mountain regions of the United States. Our corporate headquarters is located at 5851 Legacy Circle, Plano, Texas 75024, and our phone number is 972-673-2000. 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, making the Company's Scope 1 and 2 CO_2e emissions negative today, with a goal to reach Net Zero for our Scope 1, Scope 2 and Scope 3 CO_2e emissions within this decade, primarily through increasing the amount of captured industrial-sourced CO_2 used in its operations. 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.

Our CO_2 EOR oil recovery operations result in the associated underground storage of CO_2. This means that Denbury's activities are supporting and advancing the national energy transition today through the increasing use of industrially sourced CO_2 in EOR operations, as well as building out a dedicated CCUS platform for long-term carbon management for third parties at scale.

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

- leveraging our extensive CO_2 pipeline assets and CO_2 EOR expertise to expand our operations and leadership position in the emerging CCUS industry;
- seeking 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;
- increasing the value of our assets by applying our technical expertise in CO_2 tertiary recovery, together with a combination of other exploration, development, exploitation and marketing skills and practices;
- managing a disciplined capital allocation process to maximize the rates of return on our investments and organically fund growth while balancing with the return of capital to shareholders when generating free cash; and
- operating a growing, profitable and sustainable company that is dedicated to bettering our employees, our environment and our communities.

As further described in Note 1, *Nature of Operations and Summary of Significant Accounting Policies – 2020 Emergence from Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code*, 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. As part of the plan of reorganization, upon emergence from bankruptcy, all of the Predecessor's previously authorized and/or issued common stock or stock equivalents were cancelled, and new common stock was issued to the Predecessor's debt holders and equity holders upon cancellation of approximately $2.1 billion principal amount of debt and all of the Predecessor's equity instruments. 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 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to reports filed pursuant to Sections 13(a) and 15(d) of the Securities Exchange Act of 1934, as amended, or the Exchange Act, are filed with the Securities and Exchange Commission (the "SEC") and are available free of charge on or through our website, www.denbury.com, as soon as reasonably practicable after we electronically file such reports with the 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. The information contained on our website is not incorporated by reference into our SEC filings unless specifically noted otherwise. The investor relations page on our website also contains links to public conference calls, conference presentations and webcasts, corporate presentations, and our corporate responsibility report, including information that may be deemed material to investors, in order to achieve broad, non-exclusionary distribution of information to the public and for complying with our disclosure obligations under Regulation FD. The information disclosed on our website under "Investor Relations" should be reviewed by investors and other members of the public in order to fully understand our financial and operating results.

BUSINESS ENVIRONMENT AND 2022 DEVELOPMENTS

Since our production is 97% oil, oil prices generally constitute the single largest variable in our operating results. Since 2020, oil prices have increased, largely due to increased demand since the height of the COVID-19 coronavirus ("COVID-19") pandemic in 2020 and 2021, plus the effect on energy markets and prices since the Russian attacks on Ukraine, with NYMEX WTI oil prices averaging approximately $94 per barrel in 2022, $68 per barrel in 2021, and $39 per barrel in 2020. The Company's financial results improved from 2021 to 2022 due to higher oil prices, although the positive oil price impact was offset in part by the commodity hedges we were obligated to put in place through mid-2022 under the one-time requirement of our bank credit facility shortly after we emerged from bankruptcy in September 2020. Our financial results in 2022 were further impacted by inflationary pressures, primarily increasing our power costs, service costs and labor costs, caused in part by worldwide and U.S. supply chain issues. During 2022, we utilized our cash flow to primarily fund our oil and gas development and to secure CO_2 storage capacity for future CCUS activities, and with the excess cash flow resulting from higher oil prices, we returned capital to shareholders through a share repurchase program.

The following include some of our key 2022 business developments:

- Continued development of our Cedar Creek Anticline ("CCA") EOR project in Montana and North Dakota, a carbon-negative CO_2 EOR project, with CO_2 injection commencing in early 2022 and initial production response anticipated in the second half of 2023.
- Progressed the expansion of CO_2 EOR developments at several fields, including Beaver Creek, Soso, Heidelberg and Cranfield.
- Utilized excess cash flow to repurchase 1.6 million shares of Denbury common stock for approximately $100 million at an average price of $61.92 per share, leaving $250 million remaining authorized for future repurchases under our share repurchase program.
- Amended the Company's senior secured bank credit facility, increasing the borrowing base and lender commitments to $750 million, extending the maturity to 2027, and relaxing various covenants.
- Executed six agreements with customers for the potential future transportation and/or storage of industrial-sourced CO_2 covering approximately 18 Mmtpa, raising our cumulative total of CO_2 covered under future transportation/storage agreements to approximately 20 Mmtpa.
- Expanded our dedicated CO_2 storage portfolio to a total of seven contracted sites with estimated storage potential of approximately 2 billion metric tons, with planned sites in Alabama, Mississippi, Louisiana, and Texas.
- Invested $10 million in the project development company of a planned blue hydrogen/ammonia facility.
- Submitted our first Class VI well permits for injecting CO_2 into permanent geologic storage.

CARBON CAPTURE, UTILIZATION AND STORAGE

CCUS is a process that captures CO_2 from industrial sources and either reuses or stores the CO_2 in geologic formations in order to prevent its release into the atmosphere. We utilize CO_2 from industrial sources in our EOR operations, and our extensive CO_2 pipeline infrastructure and operations, particularly in the Gulf Coast, are strategically located in close proximity to both large sources of industrial emissions and geological formations well-suited for permanent storage. In the Rocky Mountain region, all of the CO_2 we utilize in our EOR operations is from industrial sources and is transported through our extensive CO_2 pipeline system. While industrial CO_2 emissions in the Rocky Mountain region are not as significant as in the Gulf Coast, we believe the Rocky Mountain region also holds great potential for CCUS. We believe that the assets and technical expertise required for CCUS are highly aligned with our existing CO_2 EOR operations. For more than 20 years, Denbury has been transporting and utilizing CO_2 in association with its EOR operations, and the cumulative associated storage of CO_2 underground through its EOR operations totals more than 240 million metric tons to date.

Supportive U.S. government policy and public pressure on industrial CO_2 emitters provide strong incentives for them to capture their CO_2 emissions; for example, in January 2021, the IRS issued final regulations under Section 45Q of the

Internal Revenue Code ("Section 45Q") on the expanded carbon capture tax credit, implementing a number of changes and clarifications to previous regulations which provided a tax incentive of $35 per ton for CO_2 used in enhanced oil recovery and $50 per ton for CO_2 permanently sequestered in geologic formations outside of EOR. In August 2022, the Inflation Reduction Act was passed and increased the value of the tax credits from $50 per ton of sequestered CO_2 to $85 per ton (subject to certain qualifications and adjustments), and from $35 per ton of CO_2 used for enhanced oil recovery (EOR) to $60 per ton (subject to certain qualifications and adjustments). The tax credit is available on volumes of permanently sequestered CO_2 to the owner of the capture facilities for a 12-year period for qualifying facilities that begin construction before January 1, 2033. In addition to the Section 45Q tax credits, some entities may be eligible for other financial incentives or benefits for products that are created through CCUS.

We believe the incentives offered under Section 45Q will drive demand for CCUS and will allow us to collect a fee for the transportation and storage of captured industrial-sourced CO_2, and further expand its utilization in our EOR operations. While a portion of the CO_2 we currently utilize in our EOR operations is captured from industrial sources and qualifies as CCUS, we have historically paid a fee for that CO_2 as those arrangements were entered into many years ago. As the enhanced Section 45Q regulations are relatively new, it will likely take several years for new capture facilities to be built and for dedicated storage sites to be developed.

As we seek to grow our CCUS business and pursue new CCUS opportunities, we have focused on the following strategic priorities:

- securing transportation and storage agreements with industrial emitters;
- adding safe, reliable, uninterruptible and secure permanent storage capacity through development of a diverse portfolio of subsurface storage sites;
- increasing our carbon-negative oil production by seeking to replace the use of naturally-sourced CO_2 in our EOR operations;
- preparing for a capital efficient expansion of our Green Pipeline capacity to meet expected rapid growth in demand from Gulf Coast industrial facility owners; and
- pursuing strategic partnerships throughout the CCUS value chain.

Transportation and Storage

As of December 31, 2022, we had agreements with eight customers for the future transportation and/or storage of CO_2 from industrial sources covering 20 Mmtpa, 18 Mmtpa of which was added during 2022. Our largest agreement is with a planned clean hydrogen-ammonia complex called Ascension Clean Energy ("ACE"). During 2022, we invested $10 million in the project development company of ACE, (Clean Hydrogen Works), while also signing a definitive agreement for the transportation and storage of CO_2 for the first two blocks of the proposed plant. We have committed to investing another $10 million when certain milestones are achieved, which is expected in 2023. The planned clean hydrogen-ammonia complex is targeting a final investment decision in 2024 and is expected to include two ammonia blocks with estimated CO_2 capture of up to 12 Mmtpa, with ammonia production from the first block expected to commence in 2027. Our agreements today are largely supported by planned ammonia/hydrogen plants, but also include plants proposing to produce biofuels, low carbon fuels, and methanol. Our agreements are with customers ranging from large international companies, such as Nutrien and Mitsubishi, to companies that are in the project development stage. We are working with many additional companies and projects on proposed future capture projects and expect to continue to add to our future business opportunities during 2023. We currently expect initial transportation and/or storage volumes associated with CCUS in 2025.

Storage Sites

At December 31, 2022, the Company had seven planned storage sites under contract with estimated potential permanent storage of approximately 2 billion metric tons. The Company's storage portfolio spans the U.S. Gulf Coast, including planned sequestration sites in Alabama, Mississippi, Louisiana, and Texas. Most of these sites are located in close proximity to our Gulf Coast CO_2 pipeline system. We are progressing development at these sites and submitted our first Class VI well permits for injecting CO_2 into permanent geologic storage in late 2022. We anticipate additional submittals during 2023, expect to drill test wells in 2023, and estimate first injection to begin in 2025. We are also evaluating potential CO_2 storage sites in the Rocky Mountain region in close proximity to our extensive CO_2 pipeline system.

OIL AND NATURAL GAS OPERATIONS

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, Wyoming and North Dakota. Approximately 97% of our production is oil, and over two-thirds of our production is from CO_2 EOR. Over time, we have grown primarily through the acquisition of mature oil fields, where we focus on increasing the value of those properties through a combination of exploitation, drilling and proven engineering extraction processes, with our most significant emphasis relating to CO_2 EOR operations. Our current portfolio of CO_2 EOR projects provides us with significant oil production and reserve growth potential, assuming crude oil prices are at levels that support the development of those projects.

We own and operate more than 1,300 miles of CO_2 transportation pipelines. Our extensive CO_2 pipeline infrastructure in the Gulf Coast and Rocky Mountain regions gives us the ability to deliver CO_2 from our natural and industrial CO_2 sources for use in our CO_2 EOR fields, as well as to deliver CO_2 to our customers who are industrial end-users of CO_2 or EOR customers. In the future, we plan to utilize these same pipelines for the transportation and storage of CO_2 in our emerging CCUS business. Our Green Pipeline currently has ample capacity to handle additional volumes, and we can further expand capacity by adding pump stations or looping sections of the pipeline.

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, 2022, 2021 and 2020 (see the summary of D&M's report as of December 31, 2022 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 each year 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, 2022, 2021 and 2020, as well as PV-10 Values and Standardized Measures for each period. The Company's December 31, 2022 proved oil and natural gas reserve quantities and PV-10 Values increased from December 31, 2021 due largely to the increase in oil prices used in preparing the December 31, 2021 and 2022 reserve information. The average NYMEX oil price used in estimating our proved reserves increased from $66.56 per Bbl at December 31, 2021, to $93.67 per Bbl at December 31, 2022. 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 *Field Summary Table* below within this section and *Supplemental Oil and Natural Gas Disclosures (Unaudited)* to the consolidated financial statements for further discussion of reserve inputs and changes between periods.

Denbury Inc.

	December 31,		
	2022	2021	2020
Estimated proved reserves			
Oil (MBbls)	197,266	188,938	140,499
Natural gas (MMcf)	29,585	16,506	15,604
Oil equivalent (MBOE)	202,197	191,689	143,100
Reserve volumes categories			
Proved developed producing			
Oil (MBbls)	177,589	164,744	123,802
Natural gas (MMcf)	26,744	14,844	14,132
Oil equivalent (MBOE)	182,046	167,218	126,158
Proved developed non-producing			
Oil (MBbls)	15,754	14,403	12,600
Natural gas (MMcf)	2,841	1,662	1,472
Oil equivalent (MBOE)	16,228	14,680	12,845
Proved undeveloped			
Oil (MBbls)	3,923	9,791	4,097
Oil equivalent (MBOE)	3,923	9,791	4,097
Percentage of total MBOE			
Proved developed producing	90 %	87 %	88 %
Proved developed non-producing	8 %	8 %	9 %
Proved undeveloped	2 %	5 %	3 %
Representative oil and natural gas prices(1)			
Oil (NYMEX price per Bbl)	$ 93.67	$ 66.56	$ 39.57
Natural gas (Henry Hub price per MMBtu)	6.36	3.60	1.99
Present values (in thousands)(2)			
Standardized measure of discounted estimated future net cash flows after income taxes ("Standardized Measure") (GAAP measure)	$ 3,490,923	$ 2,187,051	$ 654,734
Discounted estimated future income tax	966,133	486,771	48,346
Discounted estimated future net cash flows before income taxes (PV-10 Value) (non-GAAP measure)(3)	$ 4,457,056	$ 2,673,822	$ 703,080

(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. 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, and as a result, the impact of these contracts is not included in the prices used in determining our reserve quantities or values. 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 the 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 $0.65 per Bbl below representative NYMEX oil prices as of December 31, 2022, compared to $2.70 per Bbl below NYMEX oil prices as of December 31, 2021, and $3.73 per Bbl below NYMEX oil prices as of December 31, 2020.

(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. 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.

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, 2022, our estimated proved undeveloped reserves totaled approximately 3.9 MMBOE, or approximately 2% of our estimated total proved reserves. Our proved undeveloped reserves were 5.9 MMBOE (60%) lower than at December 31, 2021. During 2022, we spent approximately $53.2 million to convert 5.3 MMBOE of proved undeveloped reserves to proved developed reserves, primarily related to non-tertiary development activities at Heidelberg and Beaver Creek. During 2022, we added an additional 1.1 MMBOE of estimated proved undeveloped reserves primarily related to tertiary operations at Hastings and Beaver Creek fields, and recognized net downward revisions of our proved undeveloped reserves of 1.7 MMBOE.

During 2022, we provided oil and natural gas reserve estimates for 2021 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, 2021.

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 12 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 multidiscipline 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, a member of which is the Chairman of our Board, who 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.

Field Summary Table. The following table provides a summary by field and region of selected proved oil and natural gas reserves information, including total proved reserves quantities as of December 31, 2022, and average daily sales volumes for 2022, all based on Denbury's net revenue interest ("NRI"). The reserves 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 *Oil and Natural Gas Reserve Estimates* above and *Supplemental Oil and Natural Gas Disclosures (Unaudited)* in the consolidated financial statements.

	Proved Reserves as of December 31, 2022(1)				2022 Average Daily Sales Volumes		
	Oil (MBbls)	Natural Gas (MMcf)	MBOEs	% of Company Total MBOEs	Oil (Bbls/d)	Natural Gas (Mcf/d)	Average 2022 NRI
Tertiary oil and gas properties							
Gulf Coast region							
Delhi	9,700	—	9,700	4.8 %	2,559	—	58.1 %
Hastings	18,988	—	18,988	9.4 %	4,285	—	80.0 %
Heidelberg	15,106	—	15,106	7.5 %	3,605	—	81.1 %
Oyster Bayou	15,190	—	15,190	7.5 %	3,518	—	87.4 %
Tinsley	19,130	—	19,130	9.5 %	2,860	—	81.3 %
Other(2)	15,046	—	15,046	7.4 %	5,529	—	73.6 %
Total Gulf Coast region	93,160	—	93,160	46.1 %	22,356	—	76.6 %
Rocky Mountain region							
Bell Creek	9,351	—	9,351	4.6 %	4,082	—	84.6 %
Wind River Basin	12,378		12,378	6.1 %	3,020		83.2 %
Other(3)	6,194	—	6,194	3.1 %	2,546	—	24.6 %
Total Rocky Mountain region	27,923	—	27,923	13.8 %	9,648	—	51.0 %
Total tertiary properties	121,083	—	121,083	59.9 %	32,004	—	66.6 %
Non-tertiary oil and gas properties							
Gulf Coast region							
Total Gulf Coast region	17,816	13,751	20,108	9.9 %	3,106	3,248	29.6 %
Rocky Mountain region							
Cedar Creek Anticline(4)	55,695	10,045	57,369	28.4 %	9,463	1,567	80.0 %
Other(5)	2,672	5,789	3,637	1.8 %	729	4,223	69.0 %
Total Rocky Mountain region	58,367	15,834	61,006	30.2 %	10,192	5,790	78.8 %
Total non-tertiary properties	76,183	29,585	81,114	40.1 %	13,298	9,038	56.3 %
Company Total	197,266	29,585	202,197	100.0 %	45,302	9,038	63.1 %

(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 2022, which were $93.67 per Bbl for crude oil and $6.36 per MMBtu for natural gas.

(2) Includes Brookhaven, Cranfield, Eucutta, Little Creek, Mallalieu, Martinville, McComb, Soso and West Yellow Creek fields.

(3) Includes Salt Creek and Grieve fields.

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

(5) Includes non-tertiary operations from Wind River Basin, as well as Hartzog Draw and Bell Creek fields.

Enhanced Oil Recovery. EOR using CO_2 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. During the year ended December 31, 2022, approximately 40% of the CO_2 utilized in our operated oil and gas operations was industrial-sourced CO_2 and approximately 28% of our production for 2022 was carbon-negative, meaning the total amount of industrial-sourced CO_2 injected more than offset Scope 1, 2, and 3 CO_2e emissions (see *Climate Change and Environmental Considerations* below).

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:

- a lower exploration risk, as we are operating oil fields that have significant historical production and reservoir and geological data;
- lower production decline rates than unconventional development;
- reasonable return metrics at currently anticipated long-term prices;
- 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;
- being 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
- allowing us to concurrently store CO_2 captured from industrial sources in the same underground formations that previously trapped and stored oil and natural gas.

Our tertiary operations represent 68% of our 2022 total production (on a BOE basis). At year-end 2022, the proved oil reserves in our tertiary recovery oil fields had an estimated PV-10 Value of approximately $2.9 billion, or 64% of our total PV-10 Value, and represented 60% of our total proved reserves. In addition, there are significant probable and possible reserves at several other fields for which tertiary operations are underway or planned.

Gulf Coast Region Assets

Gulf Coast Oil Fields

Our CO_2 EOR operations began in August 1999 with the acquisition of Little Creek Field, which is our longest-producing CO_2 EOR flood. Our most mature CO_2 EOR properties are generally located along our NEJD CO_2 pipeline in southwest Mississippi and Louisiana and our Free State Pipeline in east Mississippi. These properties include Brookhaven, Cranfield, Eucutta, Little Creek, Mallalieu, Martinville, McComb and Soso fields, which have been producing under CO_2 EOR for some time, and their production is generally declining. We commenced tertiary floods at both Tinsley and Heidelberg fields in Mississippi during 2008, and at Delhi Field in Louisiana in 2009. Many of our Mississippi fields contain multiple reservoirs that are amenable to CO_2 EOR. Accordingly, we often find opportunities to expand the floods to new development areas over many years or even decades.

We further expanded tertiary operations to Texas with the acquisitions of interests in Oyster Bayou and Hastings fields in 2007 and 2009, respectively. Oyster Bayou is located in southeast Texas, east of Galveston Bay and Hastings Field is located south of Houston, Texas. Concurrent with the completion of the Green Pipeline in 2010, we initiated tertiary floods at these fields in 2010. We began producing oil from our tertiary operations at Oyster Bayou Field in 2011 and Hastings Field in 2012. Incremental development efforts continue at both fields today. These fields accounted for 35% of our Gulf Coast tertiary production in 2022.

In addition to our tertiary operations in the Gulf Coast region, we currently own interests in several properties that are currently not under CO_2 flood, the most significant of which are Conroe, Thompson and Webster fields in Texas. We continue to evaluate the potential to progress CO_2 EOR development in these fields, the development of which is primarily dependent upon capital availability and priorities, future oil prices and in some cases pipeline construction.

CO_2 Sources

Natural CO_2 Sources

Our primary Gulf Coast CO_2 source, Jackson Dome, is a large and relatively pure source of naturally occurring CO_2 (98% CO_2) and, to our knowledge, the only significant underground deposit of CO_2 in the United States east of the Mississippi River. Jackson Dome provides us a significant competitive advantage in the acquisition and development of properties in Mississippi, Louisiana and southeastern Texas that are well suited for CO_2 EOR. We have drilled numerous CO_2-producing wells in Jackson Dome over the years. As of December 31, 2022, we have estimated proved CO_2 reserves in Jackson Dome of 3.8 Tcf. The proved CO_2 reserve estimates are based on a gross (8/8ths) basis, of which our net revenue interest is approximately 3.0 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 our customers who are industrial end-users of CO_2 or EOR customers, as we are responsible for distributing the entire CO_2 production stream.

In addition to our proved reserves, we estimate that we have 1.4 Tcf, 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.

Industrial-sourced CO_2

In addition to our naturally occurring CO_2 source at Jackson Dome, in our tertiary operations we utilize CO_2 captured from industrial sources which would otherwise be released into the atmosphere. Industrial sources of CO_2 help us recover additional oil from mature oil fields and, we believe, also provide an economical way to reduce CO_2 emissions through the associated underground storage of CO_2 which occurs as part of our oil-producing EOR operations (see *Carbon Capture, Utilization and Storage* above). In the Gulf Coast, we are currently party to two long-term contracts to purchase CO_2: an industrial facility in Port Arthur, Texas and an industrial facility in Geismar, Louisiana, which combined supplied an average of approximately 55 MMcf/d of CO_2 to our EOR operations during 2022. During the year ended December 31, 2022, approximately 14% of the CO_2 utilized in our Gulf Coast EOR operations was industrial-sourced CO_2.

In the Gulf Coast region, approximately 76% of our average daily CO_2 produced from Jackson Dome or captured from industrial sources in 2022 was used in our operated tertiary recovery operations, compared to 76% in 2021 and 77% in 2020, with the balance delivered to third-party industrial end-users or EOR customers. During 2022, we used an average of 400 MMcf/d of CO_2 (including CO_2 captured from industrial sources) for our tertiary activities.

CO_2 Pipelines

We own nearly 925 miles of CO_2 pipelines in the Gulf Coast region, which gives us the ability to deliver CO_2 throughout the region. 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. The following table summarizes our most significant CO_2 pipelines owned and operated in the Gulf Coast region as of December 31, 2022:

CO_2 pipelines[(1)]	Completion Date	Pipeline Diameter (in inches)	Pipeline Mileage	Service Area
Green Pipeline	2010	24”	320	Gulf Coast corridor from near Donaldsonville, Louisiana to Hastings Field in Texas; including connections to 2 industrial-source CO_2 providers
NEJD Pipeline	1986	20”	183	Jackson Dome CO_2 source to Green Pipeline connection
Delta Pipeline	2009	24”	111	Jackson Dome CO_2 source to Delhi Field in Louisiana
Free State Pipeline	2005	20”	91	Jackson Dome CO_2 source to West Yellow Creek in Mississippi
West Gwinville	1959/2008[(2)]	18”	51	NEJD Pipeline to Cranfield Field

(1) The Company has other intrafield CO_2 pipelines in the Gulf Coast region that total approximately 168 miles.
(2) Repurposed from a natural gas pipeline to a CO_2 pipeline in 2008.

Rocky Mountain Region Assets

Rocky Mountain Oil Fields

We began operations in the Rocky Mountain region in 2010 with the acquisition of Encore Acquisition Company. Bell Creek Field was the first CO_2 EOR flood we developed in this region which began tertiary production in 2013. We have added several properties to our portfolio in the Rocky Mountain region over time, including Grieve Field in 2011, Hartzog Draw Field in 2012, and the acquisition of additional interests at CCA in 2013. In March 2021, we acquired a nearly 100% working interest (83% net revenue interest) in the Big Sand Draw and Beaver Creek EOR fields in Wyoming, including surface facilities and a 46-mile CO_2 transportation pipeline to the acquired fields.

CCA is the largest property that we own and currently our largest producing property, contributing approximately 21% of our 2022 total sales volumes. Historical production from the property has primarily been from the Red River interval. CCA 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.

In early-February 2022, we commenced CO_2 injection in the first phase of our CCA EOR project, and currently expect tertiary oil production response from CCA in the second half of 2023. In addition, drilling and facility construction at the Company's Pennel CO_2 pilot, in advance of Phase 2 development of CCA, commenced during the third quarter of 2022. In addition to these oil fields, we continue to evaluate tertiary potential in Hartzog Draw Field located in the Powder River Basin of northeastern Wyoming, the development of which is primarily dependent upon capital availability and priorities and future oil prices. The field is located approximately 12 miles from our Greencore Pipeline.

CO_2 Sources

All CO_2 used in our Rocky Mountain tertiary operations is captured from industrial sources. We own an overriding royalty interest equivalent to an approximate one-third ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field. LaBarge Field is located in southwestern Wyoming, and as of December 31, 2022, our interest in LaBarge Field held approximately 1.0 Tcf of proved CO_2 reserves. During 2022, we received an average of approximately 151 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 or sold to another third-party operator. 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.

We also have a contract in place to receive all of the CO_2 from the 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. We received 24 MMcf/d of CO_2 volumes from this source in 2022. 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 Rocky Mountain region EOR development plans.

CO_2 Pipelines

The 20-inch Greencore Pipeline in Wyoming is the first CO_2 pipeline we constructed in the Rocky Mountain region. The 232-mile pipeline begins at the Lost Cabin gas plant in Wyoming and terminates at Bell Creek Field in Montana. In 2021, we completed construction of the CCA CO_2 pipeline, which delivers CO_2 to our new tertiary development project at CCA. The following table summarizes our most significant CO_2 pipelines owned and operated in the Rocky Mountain region as of December 31, 2022:

CO_2 pipelines[(1)]	Completion Date	Pipeline Diameter (in inches)	Pipeline Mileage	Service Area
Greencore Pipeline	2012	20”	232	Lost Cabin gas plant in Wyoming to Bell Creek Field in Montana
CCA Pipeline	2021	16”	105	Bell Creek Field in Montana to CCA
Beaver Creek Pipeline	2008	8”	46	Wyoming Wind River Basin properties

(1) The Company has other intrafield CO_2 pipelines in the Rocky Mountain region that total approximately 22 miles.

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, 2022:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast region	189,568	147,857	286,700	17,963	476,268	165,820
Rocky Mountain region	385,443	345,167	106,361	20,032	491,804	365,199
Total	575,011	493,024	393,061	37,995	968,072	531,019

The percentage of our net undeveloped acreage that is subject to expiration over the next three years, if not renewed, is approximately 6% in 2023, and none in 2024 and 2025.

Productive Wells

The following table sets forth our gross and net productive oil and natural gas wells as of December 31, 2022:

	Producing Oil Wells		Producing Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated wells						
Gulf Coast region	1,047	919	120	112	1,167	1,031
Rocky Mountain region	984	946	264	233	1,248	1,179
Total	2,031	1,865	384	345	2,415	2,210
Non-operated wells						
Gulf Coast region	45	19	—	—	45	19
Rocky Mountain region	554	124	76	27	630	151
Total	599	143	76	27	675	170
Total wells						
Gulf Coast region	1,092	938	120	112	1,212	1,050
Rocky Mountain region	1,538	1,070	340	260	1,878	1,330
Total	2,630	2,008	460	372	3,090	2,380

Drilling Activity

The following table sets forth the results of our drilling activities over the last three years. As of December 31, 2022, we had one well in progress at Cabin Creek.

	Year Ended December 31,					
	2022		2021		2020	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells(1)						
Productive(2)	1	1	—	—	—	—
Non-productive(3)	—	—	—	—	—	—
Development wells(1)(4)						
Productive(2)	10	9	12	4	5	3
Non-productive(3)(5)	—	—	1	—	—	—
Total	11	10	13	4	5	3

(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) Includes 8 productive gross wells and 1 non-productive gross well during 2021, and 2 productive gross wells during 2020, in which we incurred no cost but have an overriding royalty interest prior to the combined payout of the wells. Subsequent to payout, Denbury will hold and bear the cost of its working interest in each well.

(5) During 2022, an additional 7 wells were drilled for water or CO_2 injection purposes. There were no wells drilled during 2021 or 2020 for water or CO_2 injection purposes

Sales Volumes and Unit Prices

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, 2022, 2021 and 2020:

	Year Ended December 31,		
	2022	2021	2020
Net sales volumes			
Gulf Coast region			
Oil (MBbls)	9,293	9,991	10,958
Natural gas (MMcf)	1,186	1,347	1,612
Total Gulf Coast region (MBOE)	9,491	10,216	11,227
Rocky Mountain region			
Oil (MBbls)	7,242	7,266	7,278
Natural gas (MMcf)	2,113	1,914	1,293
Total Rocky Mountain region (MBOE)	7,594	7,585	7,494
Total Company (MBOE)(1)	17,085	17,801	18,721
Average sales prices – excluding impact of derivative settlements			
Gulf Coast region			
Oil (per Bbl)	$ 94.20	$ 66.48	$ 38.44
Natural gas (per Mcf)	6.44	3.97	1.98
Rocky Mountain region			
Oil (per Bbl)	$ 94.41	$ 66.58	$ 36.79
Natural gas (per Mcf)	5.65	3.44	0.77
Total Company			
Oil (per Bbl)	$ 94.29	$ 66.52	$ 37.78
Natural gas (per Mcf)	5.93	3.66	1.44
Average production cost (per BOE sold)(2)			
Gulf Coast region(3)	$ 30.00	$ 22.50	$ 18.20
Rocky Mountain region	28.67	25.67	19.63
Total Company(3)	29.41	23.85	18.78

(1) Total Company sales volumes include 71 MBOE related to properties divested during 2020.
(2) Excludes oil and natural gas ad valorem and production taxes.
(3) Production costs during 2021 include a $16.1 million benefit resulting from compensation under certain of the Company's power agreements for power interruption during the severe weather storm in February 2021 which created widespread power outages in Texas and disrupted the Company's operations. If these amounts were excluded, production cost per BOE for the Gulf Coast region and total Company would have averaged $24.07 and $24.75, respectively, for the year ended December 31, 2021. In addition, production costs during 2020 include insurance reimbursements of $15.4 million related to recovery of prior years' expenses. 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.

Further information regarding average sales volumes, 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 year ended December 31, 2022, two purchasers each accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (27%) and Hunt Crude Oil Supply Company (11%).

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, there is no assurance that we will always be able to market all of our production or obtain favorable prices.

Oil Marketing and Differentials

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. Our crude oil prices in the Gulf Coast region have historically been highly correlated to the changes in prices of crude oil sold under the Light Louisiana Sweet ("LLS") index. 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 and Casper, Wyoming, although some of our production may ultimately be transported by third parties to Cushing, Oklahoma and 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.

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.

CLIMATE CHANGE AND ENVIRONMENTAL CONSIDERATIONS

Climate change, which is a specifically identified part of our broader efforts to operate in a manner consonant with ESG standards and goals, is a continuing global concern for governments, businesses, and society. The reduction of GHG emissions is important, and we take the responsibility of protecting our environment seriously. Part of our obligation is to report GHG emissions and develop procedures and methods to collect data critical for calculating these emissions. In addition, our operating strategy, which focuses on CO_2 EOR and CCUS, has measurable environmental benefits. We are committed to utilizing emerging technologies, where feasible, to capture or reduce emissions and to lower our GHG intensity.

We strive to be environmentally responsible in all aspects of our operations. Our operations have been subject to federal, state and local environmental compliance for many years, the costs of which are well integrated into our budgeting and our operating results. With our focus on CO_2 EOR, we offer environmental benefits not generally associated with oil and gas operations. We utilize technology and techniques that reduce the risks to, and impacts on, the environment. Our programs include measures to prevent spills and releases and to quickly respond to incidents if they do occur; efforts to manage, minimize and remediate our environmental impacts; and an operating strategy that is directly focused on our carbon footprint.

As the world demands energy to fuel tomorrow's economy and provide a better quality of life, we must meet the demand with a focus on reducing GHG emissions. The Greenhouse Gas Protocol Corporate Accounting and Reporting Standard ("Greenhouse Gas Protocol") classifies a company's GHG emissions into three scopes: Scope 1 emissions are direct emissions from owned or controlled sources; Scope 2 emissions are indirect emissions from the generation of purchased energy; and Scope 3 emissions are all indirect emissions (not included in Scope 2) that occur in the value chain of the reporting company, including both upstream and downstream emissions. The utilization of industrial-sourced CO_2 in EOR significantly reduces the carbon footprint of our oil production, making our Scope 1 and 2 CO_2e emissions negative today. We have set a target, within this decade, to reach Net Zero for our Scope 1, Scope 2 and those Scope 3 emissions that result from a consumer's use of the oil and natural gas we sell (defined as Category 11 emissions by the Greenhouse Gas Protocol).

In our Corporate Responsibility Report, which is published on our website, we report in detail our direct GHG emissions resulting from our operations, as well as indirect GHG emissions associated with the consumption of electricity.

In addition, we are committed to engaging with stakeholders, policy makers, regulators, and our industry on climate change and ESG issues and to addressing our impact on the environment. The Sustainability and Governance Committee of the Board of Directors oversees our overall ESG strategy including health and safety, climate change, environmental, social and community policies, practices and procedures. The Committee focuses upon climate change risk management and strategy, CCUS activities, sustainability targets, and operating efficiencies, along with broader climate change concerns.

HUMAN CAPITAL RESOURCES

Our employees are Denbury's greatest resource, and each individual helps shape Denbury into a unique and exceptional place to work. Our employees' ideas, passion and collective efforts are what produce winning results for our Company. We support a talented and diverse workforce that lives our key values and embodies our culture. We inspire each other to make Denbury better. As of December 31, 2022, we had 765 employees, of whom 414 were employed in our field operations or at our field offices and 351 were employed at our headquarters in Plano, TX, none of whom are currently covered by a labor union or other collective bargaining arrangement.

Workforce Health and Safety

Emphasizing workforce health and safety is not only a critical element of our ESG strategy, but it has also been a central part of our practices and standards over the years. 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. With oversight from the Sustainability and Governance Committee of the Company's Board of Directors, 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.

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 benefit programs include an annual bonus plan, an employee stock purchase plan, a long-term incentive plan, Company matched 401(k) plan, competitive healthcare and insurance benefits, health savings and flexible spending accounts and employee assistance programs.

Diversity, Equity and Inclusion

At Denbury, we strive to make diversity, equity and inclusion a part of our culture. Our management is responsible for implementing our diversity initiatives, including targeted recruitment of underrepresented populations, diversity training, and development of our diverse workforce. The Sustainability and Governance Committee of our Board of Directors provides our management with oversight and advice with respect to our practices, strategies and initiatives related to human capital management, such as diversity, equity and inclusion matters, workplace culture and talent development. We recognize the benefits we all share as a result of a diverse culture and are continually looking for ways to foster a diverse and inclusive work environment. In 2022, women and minorities accounted for 21% and 17% of our workforce, respectively, 25% and 32% of our new hires, respectively, and 25% and 13% of our Board of Directors, 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 better appreciate diversity, cultural differences, recognize unconscious biases, and increase collaboration. For 2022, our training completion rate was 96%. We continue to enhance our diversity, equity and inclusion policies which are guided by our Board of Directors 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.

Denbury aims to ensure equal opportunity in recruitment. We broaden our pool of diverse candidates by utilizing a digital recruiting program which posts available employment opportunities to websites worldwide, some of which are dedicated to diverse candidate pools, as well as by recruiting at local career workshops, several of which are specifically targeted at diverse candidates, veterans and other underrepresented groups.

Denbury believes that recruitment and advancement is based on qualification and performance. Our Company provides equal employment opportunities to all employees and applicants without regard to race, color, religion, sex (including pregnancy status, sexual orientation or gender identity), national origin, disability, age, veterans' status, marital status, genetic information (including family medical history) or any other category protected by applicable law. Denbury makes employment-related decisions, including with respect to hiring, job assignment, promotion, remuneration, training and benefits, without regard to any legally protected status. Denbury's objective is to provide a work environment that fosters mutual respect and working relationships free from discrimination, harassment or retaliation. Our management is charged with creating an atmosphere free from such conduct, and employees are responsible for respecting the rights of their co-workers.

Each year, Denbury employees have the opportunity to provide feedback on their experience, the company's culture, and improvement ideas through an annual survey. The completion rate on the 2022 annual survey was approximately 82%. Denbury values this feedback and the results are used to support continuous improvement. In 2022, Denbury had a total turnover rate of approximately 6.6%.

Community Involvement

Denbury supports its employees and the communities in which they work and live through Denbury Cares, its corporate philanthropy program. Denbury Cares includes (1) a corporate giving fund, which donates funds to charitable organizations, (2) a matching gifts program, (3) a paid volunteer day off for each employee each year and (4) an employee emergency fund to provide financial assistance to employees affected by unexpected events or natural disasters. Denbury is honored to support its employees in their efforts to enrich the communities where they live and work.

Human Rights

Denbury is committed to protecting human rights in the workplace, and at a minimum we follow all applicable national and local regulations as they pertain to the fundamental rights of all stakeholders. 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. We are committed, through our ESG strategy, to working within our business operations to reduce the risk of potential human rights violations by identifying and monitoring risks and reporting concerns and remediating violations that relate to such risks. Specifically, Denbury recognizes our responsibility with regards to: the prohibition of child labor, the prohibition of forced or coerced labor, diversity, equity and inclusion, compensation and benefits, freedom of association and collective bargaining, a workplace free from harassment and discrimination, workplace health and safety, and workplace security. Denbury respects the human, cultural and legal rights of all individuals and communities, and promotes the goals and principles of the United Nation's Universal Declaration of Human Rights, the United Nation's Guiding Principles on Business and Human Rights and the International Labor Organization's Declaration of Fundamental Principles and Rights at Work. This commitment extends to the fair treatment and meaningful involvement of all people, including Indigenous people, regardless of race, color, gender, identity or expression, national origin, religion, sexual orientation or income level. 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 "Sustainability" link.

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 can be challenging, and noncompliance can result in substantial penalties or the potential shutdown of operations. Compliance has also been complicated by an increasing trend for litigation challenging policy and regulatory changes, with judicial decisions increasing regulatory uncertainty, often delaying necessary approvals from agencies that may be the subject of conflicting injunctions, rulings or appeals. 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 laws and regulations at the federal, state and local levels. Such regulation includes requiring sometimes lengthy environmental review prior to approval of potential leasing, drilling, or other development projects; 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 compensation due to surface, and potentially pore space, owners for mineral development, enhanced oil recovery, and fluid disposal activities; 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 delay proposed development projects, 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 Pipeline 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 PHMSA to prescribe new minimum safety standards for CO_2 pipelines. In mid-2022, PHMSA announced its intention to initiate a new rulemaking to update standards for CO_2 pipelines, including requirements related to emergency preparedness and response, which new rulemaking had not occurred as of February 2023.

Both federal and state authorities have in recent years proposed and enacted new regulations and policies to limit the emission of pollutants, including GHG emissions, as part of climate change initiatives and the Clean Air Act. During the last ten years, both the EPA and Bureau of Land Management ("BLM") have proposed and issued such regulations and policies for the oil and gas industry. Those proposed and final regulations and policies were the subject of extensive administrative, judicial, and Congressional consideration during the Obama and Trump Administrations, which caused significant difficulty in determining which regulations were in force at any given time. The Biden Administration, through various executive orders and other policy statements, has made climate change a primary priority. On January 20, 2021, the Biden Administration issued Executive Order 13990, directing agencies to review all agency actions related to emissions and climate change taken under the Trump Administration. On June 30, 2021, President Biden signed into law a joint Congressional resolution disapproving the EPA's 2020 policy rules related to GHG emissions from oil and gas industry activities under the Clean Air Act. On November 2, 2021, the EPA proposed new regulations for GHG emissions. In November 2022, the EPA proposed to update, strengthen and expand its November 2021 proposed regulations to include more comprehensive emission reductions from oil and gas facilities. Public hearings on the new proposed regulations were held in January 2023, with a potential final rule to be published thereafter. In November 2022, BLM proposed new rules regulating the venting, flaring and leaks of natural gas during oil and gas production activities on federal and Indian lands. The comment period for the new proposed rules ended January 30, 2023. While BLM's proposal is listed on its regulatory agenda, the agency has not yet issued a proposed rule. Any resulting regulations adopted by the EPA or BLM could possibly be similar to, or even more stringent than, those promulgated by the agencies under the Obama Administration. 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.

CCUS Regulation

The Biden Administration has previously announced a domestic climate goal of net-zero emissions economy-wide by 2050, and committed to supporting the responsible development and deployment of CCUS technologies to make it a widely available, increasingly cost-effective, and rapidly scalable climate solution across all industrial sectors.

On February 16, 2022, pursuant to the Utilizing Significant Emissions with Innovative Technologies Act, the White House's Council on Environmental Quality ("CEQ") issued guidance for Federal agencies on the facilitation of reviews associated with the deployment of CCUS projects and carbon dioxide pipelines, and to support the efficient, orderly, and responsible deployment of CCUS projects and carbon dioxide pipelines, where appropriate. This guidance was consistent with the CEQ's report, "Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration" issued in June 2021, which identified numerous permits and/or reviews that may be required during the development of a CCUS project, some examples of which are:

- Clean Air Act New Source Review preconstruction permit;
- Clean Air Act Title V operating permit;
- Underground Injection Control ("UIC") permit;
- Environmental Assessment or Environmental Impact Statement under National Environmental Policy Act;
- Consultations with Fish and Wildlife Service pursuant to Endangered Species Act;
- Compliance with Mineral Leasing Act for geologic sequestration; and
- Compliance with PHMSA standards and regulations.

On July 27, 2022, the CEQ also established a task force to provide recommendations to the Federal government on how to ensure CCUS projects, such as carbon dioxide pipelines, are permitted in an efficient manner. The final recommendations of the CEQ on permitting, and any resultant regulatory schemes established by the Biden Administration and/or Congress, may impose additional costs related to compliance.

The Environmental Protection Agency ("EPA") has a regulatory framework under the authorities of the Safe Drinking Water Act and the Clean Air Act that regulates UIC programs and ensures the long-term, safe geologic sequestration of CO_2. The EPA also provides guidance to support state program implementation of UIC programs. This includes minimum requirements for state UIC programs and permitting for injection wells. These requirements include performance standards for well construction, operation and maintenance, monitoring and testing, reporting and recordkeeping, site closure, financial responsibility, and post injection site care. The EPA has issued regulations for six classes of underground injection wells based on type and depth of fluids injected and potential for endangerment of underground sources of drinking water. Class II wells are used to inject fluids relating to oil and gas operations, including with respect to the injection of CO_2 for EOR, while Class VI wells are used for the express purpose of injecting CO_2 for geologic storage.

Our carbon transportation and storage operations are also subject to state regulations. Numerous state legislatures have passed legislation specifically pertaining to carbon storage projects and addressing issues such as: (1) pre-requisites for obtaining a permit to drill and/or establish a carbon storage facility; (2) pore space ownership, (3) mineral rights primacy, (4) carbon dioxide ownership, and (5) long-term liability associated with carbon storage facilities. In 2022, numerous states passed new laws addressing one or more of these issues, including Mississippi and Wyoming. Management believes that we are currently in compliance with all state regulations pertaining to the development and/or operation of carbon transportation and storage projects. However, the regulatory environment around CCUS projects is in a state of rapid evolution and we anticipate that further state regulations applicable to our operations may be passed in the coming years, including within Texas and/or Louisiana.

Federal, State or Indian Leases

As of December 31, 2022, approximately 30% of our net developed acreage and 27% of our December 2022 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 Indian Affairs, and other federal and state stakeholder agencies.

New federal oil and gas leasing has resumed, although at a slower pace, after various executive orders, secretarial orders, and related litigation caused significant delay in 2021 and 2022. Recent federal oil and gas leasing and permitting decisions, however, remain subject to pending litigation in several federal courts throughout the country, and consequently the current litigation environment implies that nearly all new federal leasing and permitting decisions are likely to be subject to judicial challenge.

BLM has also announced plans to introduce a new proposed rule to update its oil and gas leasing process. The proposed rule may include increases to the fees, rents, royalty rates, bonding requirements, and updated procedures for ensuring environmental stewardship and climate change analysis for new federal oil and gas leases. While BLM's proposal is listed on its regulatory agenda and has been the subject of scoping meetings, the agency has not yet issued a proposed rule. If such a rule is finalized, any increase in the fees related to oil and gas development on federal lands will increase our costs of doing business and, consequently, affect our profitability.

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 GHG 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; (8) the Migratory Bird Treaty Act and Bald and Golden Eagle Protection Act, which protects certain bird species, including certain species that could be present on our leases, from intentional and unintentional killing and other disturbances; and (9) 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, oil and gas lease sales, and project-level master development plans. On April 20, 2022 the Council on Environmental Quality issued a final rule that updates National Environmental Policy Act regulations to remove consideration of the applicant's goals, to allow agencies greater flexibility in developing applicable review procedures, and to revise the definition of "effects" to be considered to include direct, indirect, and cumulative effects. With implementation of the new rule, the federal environmental review process is expected to continue or even increase delay in federal decision making related to oil and gas development.

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.

Item 1A. Risk Factors

The risks described below fall into five broad categories related to (1) oil price volatility and demand, (2) future executive, legislative or regulatory actions, (3) financial risks, (4) significant CCUS activities, (5) cybersecurity risks, and (6) those related to our operations and industry. These are not the only risks 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

Oil prices have been very volatile in recent years, which is expected to continue or increase, which may lead to significant periods of reduced cash flows and negatively affect our financial condition and results of operations.

Oil prices are currently 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, reaching a three-year peak over $123 per Bbl in March 2022 compared to lows averaging $17 per Bbl in April 2020. The year-to-year volatility has been due to the reduction in worldwide economic activity and oil demand amid the COVID-19 pandemic in 2020 and 2021, and in 2022 energy prices increased due to the Russian attacks on Ukraine, OPEC supply pressures and increasing oil demand. During 2022, prices ranged from a high of $123.70 in March and a low of $71.02 in December.

Oil price volatility will remain. Although global petroleum demand is currently rising faster than petroleum supply, driving higher prices during 2022, factors beyond our control could cause prices to move downward on a rapid or repeated basis, making 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 2022 average daily sales volumes and approximately 98% of our proved reserves at December 31, 2022. 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;
- 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;
- 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 COVID-19 pandemic has disrupted and will likely continue to affect worldwide economic activity, which could negatively affect demand for oil.

The continuing effect of the COVID-19 virus has resulted in a global slowdown in economic activity, disrupting supply chains, and reducing global workforces, increasing market volatility and directly impacting domestic and global oil demand, and consequently, our operational and financial performance. It is impossible to predict the ultimate degree to which future variants of COVID-19 and their spread could lead to continuing significant and material disruptions in economic activity, and oil prices, and could have a material adverse effect on our results of operations.

Geopolitical tensions, principally the Russian invasion of Ukraine, have caused and may heighten oil market volatility that could negatively affect our results of operations.

The war in Ukraine, and trade and monetary sanctions in response to the Russian invasion, could continue to significantly affect worldwide oil prices and demand, feed inflation, and cause turmoil in the global financial system and oil markets, which are the primary determinants of our results of operations. This could lead to continuing significant and material disruptions in economic activity, and oil prices, and could have a material adverse effect on our results of operations.

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.

In early 2021, the Biden Administration recommitted the United States to the Paris Climate Agreement and targeted a reduction of 50-52% GHG emissions by the year 2030. In order to achieve such goal, in 2021, the Biden Administration introduced initiatives, which include policies to address climate change, energy efficiency, and clean energy. If the Biden Administration and Congress adopt stricter standards for, and increase oversight and regulation over, the exploration and production industry at the federal level, these 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, conducted pursuant to permits and authorizations issued by the Bureau of Land Management, the Bureau of Indian Affairs, and other federal and state stakeholder agencies, may be impacted by the risks outlined above (See *Federal and State Regulations – Federal, State or Indian Leases*).

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, including heightened CO_2 pipeline regulation. Legislation and increased regulation regarding climate change or CO_2 pipeline standards or procedures could impose significant costs on us and possibly affect our financial condition and operating performance.

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.

Financial Risks

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 22, 2023, we have oil derivative contracts in place covering approximately 27,000 Bbls/d for the first half of 2023, 23,000 Bbls/d for the second half of 2023, 2,000 Bbls/d for the first half of 2024, and 1,000 Bbls/d for the second half of 2024. 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.

Continuing or worsening inflationary or supply chain issues could lower our margins and operational efficiency.

We anticipate inflationary pressures to continue into 2023 and have included these adjustments in our 2023 budget. Expectations of lingering or increasing inflationary pressures in our industry are becoming widespread (including anticipated double digit percentage price increases in certain expense categories). In addition to price increases by third-party service companies, it may become more costly for us to recruit and retain key employees, particularly specialized/technical personnel, in the face of increased competition for specialized and experienced oilfield workers.

Government and societal reaction to climate change could impact our stock price and increase our costs, while pressure to meet ESG standards may impact our business.

Increasing attention to climate change and public and investor demands that companies address climate change and ESG standards may increase our costs, reduce demand for oil or negatively impact our stock price and access to capital markets. Furthermore, organizations that advise many institutional investors on corporate governance and investment and voting decisions have developed ratings processes for evaluating companies related to ESG matters. Negative ratings by these organizations, together with ESG advocates' pressure for investors to divest fossil fuel equities and for lenders to limit funding to oil and gas producers, may lead to negative investor sentiment toward the oil and gas industry, including the Company, which could have a negative impact on our stock price. Denbury's movement into CCUS along with a focus upon climate change risk management and strategy, sustainability targets, and operating efficiencies, may mitigate some of these risks.

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 fiscal year 2023 budgetary planning, the Biden Administration 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 focused upon were 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.

Open-market sales of a substantial number of shares of our common stock acquired upon exercise by holders of our outstanding warrants, could cause the market price of our common stock to drop significantly, even if our business is doing well.

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 at prices of either $32.59 or $35.41 per share, respectively, of which outstanding warrants may convert into approximately 3.2 million shares (approximately 7%) of our common stock outstanding as of December 31, 2022. The A warrants are exercisable until September 18, 2025, and the series B warrants are exercisable until September 18, 2023, at which respective dates the warrants expire. The future exercise of a large number of warrants, followed by the subsequent sale of the acquired stock into the market, could negatively affect our common stock price. We cannot predict the likelihood of exercise of the warrants or sales of shares of our common stock acquired upon exercise, or the effect of any such sales on the prevailing market price of our common stock. Further, the future exercise of a large number of warrants will dilute our basic earnings per share.

Risks of Engaging in Significant CCUS Activities

The CCUS industry, in its infancy, is subject to multiple risks which vary from the risks we face as a mature oil and gas producer.

The CCUS industry is a relatively new and emerging one. Our ability to successfully be a leader in this industry, especially in the Gulf Coast, is subject to a multitude of risks, many of which are not in our control. Such risks include the uncertainty of evolving regulations of governmental authorities, the availability of necessary equipment for facility construction by our current and future third-party emitters and their related costs, and the attainability of requisite financing and federal and state incentive programs, all of which are required to build and bring industrial facilities to an operational status. Additionally, CCUS requires (1) captured CO_2 emissions, (2) available CO_2 pipelines, and (3) appropriately tested and prepared storage sites, which may be subject to misaligned timing. As numerous global companies have entered into, or announced plans to enter into the Gulf Coast CCUS market, we expect rigorous competition in building our CCUS operations.

Our contemplated CCUS operations are anticipated to be cash flow negative for the next several years as we build out CCUS infrastructure, consuming a major share of the excess cash flow from our other operations.

We are not expecting to generate revenues from our CCUS activities until 2025. In the interim, we will be incurring costs for the development of dedicated CO_2 storage sites which could include front-end engineering design work, feasibility studies and payments to pore space owners, as well as negotiating contracts with present or anticipated emitters of CO_2, and others. Based upon current oil futures prices, we currently expect that our cashflow from operations will fund most of the Company's capital needs, however we may consider alternative financing options as a supplemental source of capital. Although we believe that CCUS activities should be profitable for the Company over time, there are numerous risks and uncertainties that make its timing and quantification difficult to accurately predict. The financial impact of our expending capital on these activities before realizing CCUS cash flows could negatively impact our financial condition and operational results in future periods.

The CCUS industry is likely to be subject to rigorous regulatory oversight, as exemplified by PHMSA's 2022 announcement of its intention to initiate new CO_2 pipeline standards and emergency preparedness and response rules.

Federal, state, and local authorities are likely to mandate rules regarding every aspect of the CCUS industry value chain. The storage of CO_2 is expected to be regulated in a manner similar to the oil and gas industry, with permitting, bonding, reporting, and other requirements, such as the current permitting requirements by the EPA of Class VI wells to inject CO_2 for permanent storage. There is no assurance that we will be successful in obtaining permits, whether or not in a timely manner, nor have rules regarding bonding requirements been fully developed.

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. 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. In addition, in connection with COVID-19 precautions, many of our employees and those of our service providers, vendors and industry partners continue to work remotely from home or other remote-work locations, where cybersecurity protections may be less robust and cybersecurity procedures and safeguards may be less effective. 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, especially our development of fields in the CCA area in the Rocky Mountains. 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.

Certain of our operations may be limited during certain periods due to severe weather conditions or government 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 Montana, Wyoming and North Dakota, 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 extreme weather events and storm patterns, rising sea levels and periods of prolonged 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 subject to seasonal activity, 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.

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, equipment failures; 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 control events. 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 and CCUS 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 endangered.

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. Future extensions of our Green Pipeline, construction to connect third-party CO_2 emitters to storage sites, and preparation for CCUS activities 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 may be listed as threatened or endangered under the Endangered Species Act, which listing may 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 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 EOR or CCUS operations.

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, 2022 reserves, after adjustments for market differentials and transportation expenses by field, were $93.02 per Bbl for crude oil and $5.14 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.

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. Further, with the expansion of the emerging CCUS industry, we have specialized technical employees in high demand for their unique operational experience in EOR activities that would be valuable to our CCUS competitors.

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, 2022, two purchasers individually accounted for 10% or more of our oil and natural gas revenues and, in the aggregate, for 38% 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

On July 30, 2020, Denbury Resources Inc. and its subsidiaries filed petitions for reorganization in a "prepackaged" voluntary bankruptcy 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 confirming the prepackaged joint 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 as the successor reporting company of Denbury Resources Inc. On April 23, 2021, the Bankruptcy Court entered a final decree closing the Chapter 11 case captioned "In re Denbury Resources Inc., et al., Case No. 20-33801"; therefore, we have no remaining obligations related to this reorganization.

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 and regulatory proceedings are 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.

Notice of Probable Violation from Pipeline and Hazardous Materials Safety Administration ("PHMSA") Regarding Delta-Tinsley CO_2 Pipeline Failure

On May 26, 2022, the PHMSA of the U.S. Department of Transportation issued a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order ("NOPV") relating to the February 2020 pipeline failure near Satartia, Mississippi in our CO_2 pipeline running between the Tinsley and Delhi fields. The NOPV proposed a preliminarily assessed civil penalty of $3.9 million in connection with the incident, which we accrued during the second quarter of 2022. We have responded to the NOPV and are pursuing discussions with PHMSA regarding the probable violations alleged in the NOPV, the proposed civil penalty, and the nature of the compliance order contained in the NOPV.

The information under Note 14, *Commitments and Contingencies*, to the consolidated financial statements is incorporated herein by reference.

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, 2023, based on information from the Company's transfer agent, Broadridge Stock Transfer Agent, there were 232 holders of record of Denbury's common stock.

Dividends

We have not paid dividends on our Successor common stock and have no current plans to declare common stock dividends. We are permitted to pay dividends subject to the terms of our credit agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto. For further discussion, see Note 8, *Long-Term Debt*, to the consolidated financial statements.

2022 Purchases of Equity Securities

In early May 2022, our Board of Directors approved a common share repurchase program authorizing the repurchase of up to an aggregate $250 million of Denbury common shares. During June and July 2022, we purchased a total of 1,615,356 shares of Denbury common stock for $100 million under the program, at an average price of $61.92 per share. In August 2022, our Board of Directors increased the common share repurchase program by $100 million, so that $250 million remains authorized for future repurchases under the program. We are not obligated to repurchase any dollar amount or specified number of shares of our common stock under the program. The stock repurchase program has no pre-established ending date and may be modified, suspended, or discontinued at any time by the board of directors. See further discussion of this program under Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Overview – Common Share Repurchase Program*.

Fourth Quarter Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Month	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under Plans or Programs
October 2022	—	—	—	$ 250,000,000
November 2022	—	—	—	$ 250,000,000
December 2022	—	—	—	$ 250,000,000
Total	—		—	

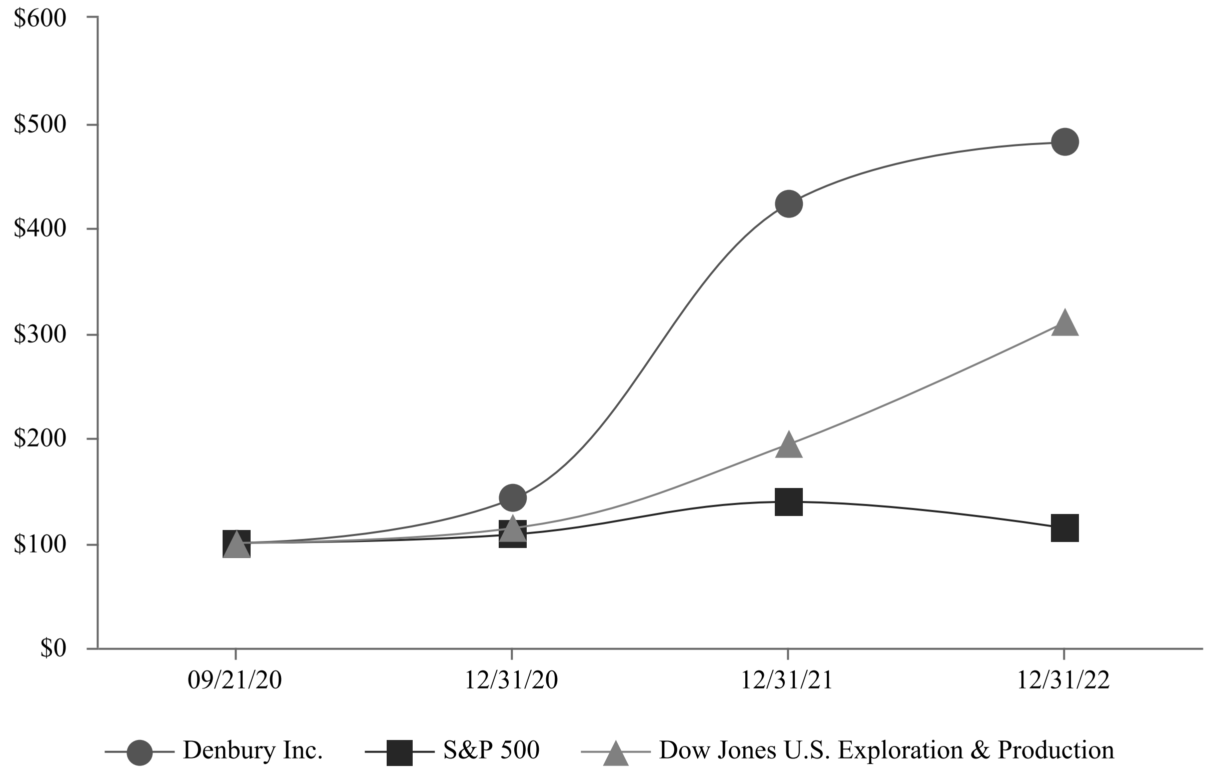
Denbury Inc.

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, 2022, 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, 2022.

SEPTEMBER 21, 2020 to DECEMBER 31, 2022
COMPARISON OF CUMULATIVE TOTAL RETURN – POST BANKRUPTCY EMERGENCE



	9/21/20	12/31/20	12/31/21	12/31/22
Denbury Inc.	$ 100	$ 142	$ 423	$ 481
S&P 500	100	108	139	114
Dow Jones U.S. Exploration & Production	100	114	194	310

Item 6. [Reserved]

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, 2020, 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, 2021, as filed with the Securities and Exchange Commission ("SEC") on February 25, 2022.

As a result of the Company's emergence from bankruptcy and adoption of fresh start accounting on September 18, 2020 (the "Emergence Date"), 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. References to "Successor" relate to the results of operations of the Company subsequent to September 18, 2020, and references to "Predecessor" relate to the results of operations of the Company prior to, and including, September 18, 2020.

OVERVIEW

Denbury is an independent energy company with operations focused in the Gulf Coast and Rocky Mountain regions. The Company is differentiated by its focus on CO_2 enhanced oil recovery ("EOR") and the emerging carbon capture, utilization, and storage ("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, making the Company's Scope 1 and 2 CO_2e emissions negative today. We have set a target, within the decade, to reach Net Zero for our Scope 1, Scope 2 and those Scope 3 emissions that result from a consumer's use of the oil and natural gas we sell (defined as Category 11 emissions by the Greenhouse Gas Protocol).

Oil Price Impact on Our Business. Our financial results are significantly impacted by changes in oil prices, as 97% of our sales volumes in 2022 were 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. Oil prices have historically been volatile and can fluctuate significantly over short periods of time. For example, average NYMEX WTI oil prices increased from the mid-$70s per Bbl range in the fourth quarter of 2021 to an average of approximately $109 per Bbl during the second quarter of 2022 before declining to an average of approximately $83 per Bbl during the fourth quarter of 2022. The increases in oil prices from 2021 levels were largely due to increased demand since the height of the COVID-19 coronavirus ("COVID-19") pandemic in 2020 and 2021, plus the effect on energy markets and prices of the Russian attacks on Ukraine.

The table below outlines selected financial items and sales volumes, along with changes in our realized oil prices, before and after commodity derivative impacts, over the last three years:

	Year Ended December 31,		
In thousands, except per-unit data	2022	2021	2020
Oil, natural gas, and related product sales	$ 1,578,682	$ 1,159,955	$ 693,209
Receipt (payment) on settlements of commodity derivatives	(315,752)	(277,240)	102,485
Oil, natural gas, and related product sales and commodity settlements, combined	$ 1,262,930	$ 882,715	$ 795,694
Average daily sales (BOE/d)	46,809	48,770	51,151
Average net realized prices			
Oil price per Bbl - excluding impact of derivative settlements	$ 94.29	$ 66.52	$ 37.78
Oil price per Bbl - including impact of derivative settlements	75.19	50.46	43.40

As shown in the table above, our oil and natural gas revenues have increased dramatically since 2020 due to increases in oil prices. However, the benefit of the increase in revenues during 2021 and 2022 was muted by the impact of higher cash payments on our commodity derivative contracts, which contracts were generally put in place as a requirement under our bank credit facility shortly after we exited bankruptcy. Beginning in the second half of 2022, less of our production was hedged, and our hedges were at more favorable prices and with a greater mix of collars, allowing us to realize a greater portion of increased oil prices. We paid $315.8 million during the year ended December 31, 2022 related to the settlement of commodity derivative contracts.

Comparative Financial Results and Highlights. We recognized net income of $480.2 million, or $8.83 per diluted common share during 2022, and net income of $56.0 million, or $1.04 per diluted common share during 2021. Drivers of the comparative operating results between 2022 and 2021 include the following:

- Oil and natural gas revenues increased by $418.7 million (36%) in 2022, all attributable to higher commodity prices, slightly offset by lower sales volumes;
- Commodity derivative expense decreased by $174.2 million consisting of a $212.8 million improvement in noncash fair value changes between periods ($137.0 million gain during 2022 compared to a $75.7 million loss during 2021), partially offset by a $38.6 million increase in cash payments upon derivative contract settlements ($315.8 million in payments during 2022 compared to $277.2 million in payments during 2021).
- Lease operating expenses increased by $77.9 million (18%), primarily due to higher power and fuel costs and workover costs from inflation and higher activity levels; and
- Taxes other than income increased $40.1 million primarily due to an increase in production taxes resulting from higher oil and gas revenues.

Common Share Repurchase Program. In early May 2022, our Board of Directors authorized a common share repurchase program for up to $250 million of outstanding Denbury common stock. During June and July 2022, the Company repurchased 1.6 million shares of Denbury common stock under this program for approximately $100 million, at an average price of $61.92 per share. In August 2022, the Board increased Denbury's stock repurchase authorization by $100 million, thus a total of $250 million of common stock currently remains authorized for future repurchases under this program. The program has no pre-established ending date and may be suspended or discontinued at any time. The Company is not obligated to repurchase any dollar amount or specific number of shares of its common stock under the program.

Cedar Creek Anticline CO_2 EOR Development. In early February 2022, we commenced CO_2 injection in the first phase of our CCA EOR project. In order to stay ahead of potential supply chain delays, and to prepare for earlier processing of CO_2 based on CO_2 injection levels being at the high end of our expectations, we increased capital investment in the second half of 2022 at CCA to accelerate our procurement of compression equipment and construction of CO_2

recycle facilities to ensure facilities are in place to handle anticipated production from the field. We continue to expect tertiary oil production response from CCA in the second half of 2023. In addition, drilling and facility construction at the Company's Pennel CO_2 pilot, in advance of Phase 2 development of CCA, commenced during the third quarter.

Advancing Carbon Capture, Utilization and Storage Activities. CCUS is a process that captures CO_2 from industrial sources and either reuses or stores the CO_2 in geologic formations in order to prevent its release into the atmosphere. We utilize CO_2 from industrial sources in our EOR operations, and our extensive CO_2 pipeline infrastructure and operations, particularly in the Gulf Coast, are strategically located in close proximity to both large sources of industrial emissions and geological formations well-suited for permanent CO_2 storage. During the year ended December 31, 2022, approximately 40% of the CO_2 utilized in our operated oil and gas operations was industrial-sourced CO_2. This compares to 33% utilized during the year ended December 31, 2021. We believe that the assets and technical expertise required for CCUS are highly aligned with our existing CO_2 EOR operations, providing us with a significant advantage and opportunity to lead in the emerging CCUS industry, as the building of a permanent carbon capture and storage business by others requires both time and capital to build assets such as those we own and have been operating for years.

We have been seeking to build our CCUS business and pursue new CCUS opportunities on two fronts: first, we have been engaged with existing and potential third-party industrial CO_2 emitters regarding CO_2 transportation and storage solutions under long term agreements; second, we have been identifying and securing potential future storage sites for permanent CO_2 storage. In 2023, our goals include continuing to capture more of the emissions market and adding storage sites to our portfolio. We also plan to drill stratigraphic wells, submit additional Class VI storage permits for our contracted sites, and purchase long-lead time items for network buildout. We currently have signed agreements covering the potential future transportation and storage of up to 20 Mmtpa from the planned capture of CO_2 emissions from existing and proposed industrial plants. On the sequestration front, we have also signed agreements securing the rights to seven future storage sites which we believe have the potential to store up to 2 billion metric tons of CO_2. Initial CCUS transportation and/or storage volumes are anticipated in 2025 and we are projecting those volumes could increase to an average of 50–70 Mmtpa by 2030.

While our use of CO_2 in EOR is currently reflected in our historical financial and operational results (as a cost), we believe the incentives offered under Section 45Q of the Internal Revenue Code and the expansion of those incentives under the August 2022 Inflation Reduction Act will drive demand for CCUS and allow us to collect a fee for the transportation and storage of captured industrial-sourced CO_2. Although we believe our first revenues associated with the storage of CO_2 will likely occur in 2025, we are currently incurring costs to engineer, conduct feasibility studies and otherwise develop and permit storage sites, along with payments to pore space owners, and will continue to advance those efforts over the next several years. In addition, we will need to expand our CO_2 pipeline network to connect to emission sites and storage sites. During the year ended December 31, 2022, we capitalized $65.0 million in "CCUS storage sites and related assets" in our Consolidated Balance Sheets, primarily consisting of acquisition costs associated with storage sites. On a long-term forward-looking basis, we currently estimate that cumulative capital investments for CCUS projects and initiatives between 2023 and 2030 will total between $1.6 billion and $2 billion with an average of $200 million to $250 million per year, and will be focused on CO_2 storage site development and pipeline costs. The highest investment period is expected in 2024 and 2025 as we plan to continue construction and development of multiple sequestration sites, including drilling Class VI injection wells and installing pipeline extensions to connect to storage sites and industrial emissions. Currently, we anticipate we can internally fund CCUS capital expenditures from free cash flows through 2030 assuming a minimum of $60 NYMEX WTI oil prices, although we may consider alternative financing options as a supplemental source of capital. As early as 2026 or 2027, we expect the CCUS business will be generating cash flows that could internally fund its development.

CAPITAL RESOURCES AND LIQUIDITY

Overview. Our cash flows from operations and availability under our senior secured bank credit facility are our primary sources of capital and liquidity. Our most significant cash capital outlays relate to our oil and gas development capital expenditures and CCUS initiatives. During the year ended December 31, 2022, we generated $520.7 million in cash flow from operations, invested net cash of $427.9 million in oil and gas and CCUS activities, and utilized net cash of $95.3 million in financing activities, primarily associated with $100.0 million of Denbury common stock purchased under the Company's stock repurchase program.

As of December 31, 2022, we had $29.0 million of outstanding borrowings and $10.1 million of outstanding letters of credit under our $750 million senior secured bank credit facility, leaving us with $710.9 million of borrowing base availability. This liquidity is more than adequate to meet our currently planned operating and capital needs. As further discussed below, based on oil price futures as of the middle of February 2023, we currently anticipate funding all of our 2023 capital budget from projected operating cash flow.

Capital Expenditure Summary. For purposes of tracking and comparing our capital budget to capital expenditure activity, we utilize data reflective of when capital expenditures are incurred, which is generally different than what is reported in our cash flow statements, which reflects when cash is actually paid. The information included in the following table reflects incurred capital expenditures for the years ended December 31, 2022, 2021 and 2020:

	Year Ended December 31,		
In thousands	2022	2021	2020
Capital expenditure summary(1)			
CCA EOR field expenditures(2)	$ 124,257	$ 35,754	$ 810
CCA CO_2 pipelines	2,520	87,688	10,942
CCA tertiary development	126,777	123,442	11,752
Non-CCA tertiary and non-tertiary fields	196,901	97,085	49,800
CO_2 sources, other CO_2 pipelines and other	8,974	1,657	660
Capitalized internal costs(3)	31,546	29,987	32,956
Oil and gas development capital expenditures	364,198	252,171	95,168
CCUS storage sites and related capital expenditures	64,605	—	—
Oil and gas and CCUS development capital expenditures	428,803	252,171	95,168
Capitalized interest	4,237	4,585	24,146
Acquisitions of oil and natural gas properties(4)	976	10,979	176
Investment in Clean Hydrogen Works(5)	10,218	—	—
Total capital expenditures	$ 444,234	$ 267,735	$ 119,490

(1) Capital expenditures in this summary are presented on an as-incurred basis (including accruals), and are $27.3 million higher, $35.7 million higher, and $10.9 million lower than the capital expenditures in the Consolidated Statements of Cash Flows for the years ended December 31, 2022, 2021, and 2020, respectively, which are presented on a cash paid basis.
(2) Includes pre-production CO_2 costs associated with the CCA EOR development project totaling $23.1 million during the year ended December 31, 2022.
(3) Includes capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.
(4) Primarily consists of working interest positions in the Wind River Basin enhanced oil recovery fields acquired on March 3, 2021.
(5) Represents an investment made during the third quarter of 2022 in the project development company ("Clean Hydrogen Works") of a planned blue hydrogen/ammonia multi-block facility, while also signing a definitive agreement for the transportation and storage of CO_2 for the first two blocks of the proposed plant. The investment is included in "Other assets" in the Consolidated Balance Sheet as of December 31, 2022. We have committed to invest another $10 million when certain project milestones are achieved, which is currently projected to occur in 2023.

Supply Chain Issues and Potential Cost Inflation. Worldwide and U.S. supply chain issues, together with higher commodity prices, power costs, service costs and tight labor markets in the U.S., increased our costs beginning in late 2021 and continued throughout 2022. Although the level of inflationary cost increases and supply chain issues has begun to level off in certain areas, we still expect additional cost and demand increases in certain categories of goods, services and wages in our operations during 2023 which could negatively impact our results of operations and cash flows in future periods. See *Results of Operations – Production Expenses* below for further discussion.

2023 Plans and Capital Budget. We estimate our total oil and natural gas development capital expenditures in 2023, excluding acquisitions and capitalized interest, will be in a range of $350 million to $370 million, and our CCUS capital expenditures will be in a range of $140 million to $160 million. At the combined midpoint of $510 million, total capital expenditures are 19% higher than expenditures in 2022, with the expected 2023 increases driven entirely by higher CCUS capital expenditures, which are primarily for the development of dedicated CO_2 storage sites and preparation for expansion of our CO_2 pipelines. In addition to the Company's budgeted capital expenditures, we expect to incur approximately $17 million for CCUS equity investments and approximately $36 million for plugging and abandonment costs.

Based on the Company's projections, including estimated production, costs, oil price differentials and other assumptions, we currently anticipate our 2023 cash flows from operations, excluding working capital changes, will approximately meet or exceed our budgeted 2023 capital expenditures and planned asset retirement obligation activities, assuming oil prices of approximately $75 per Bbl in 2023. Also, at December 31, 2022, we had $710.9 million of availability under our bank credit facility, which we believe is more than adequate to cover any near-term liquidity needs.

Senior Secured Bank Credit Agreement. In September 2020, we entered into a $575 million bank credit agreement for a senior secured revolving credit facility with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (the "Bank Credit Agreement"). Under the 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 Bank Credit Agreement. 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. The borrowing base is adjusted at the lenders' discretion and is based, in part, upon external factors over which we have no control. If our outstanding debt under the 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.

On May 4, 2022, we entered into a Second Amendment to the Bank Credit Agreement, which among other things:

- Increased the borrowing base and lender commitments from $575 million to $750 million;
- Extended the maturity date from January 30, 2024 to May 4, 2027;
- Modified the interest provisions on loans under the Bank Credit Agreement to (1) reduce the applicable margin for alternate base rate loans from 2% to 3% per annum to 1.5% to 2.5% per annum and (2) replace provisions referencing LIBOR loans with Secured Overnight Financing Rate loans, with an applicable margin of 2.5% to 3.5% per annum; and
- Permitted us to pay dividends on and repurchase our common stock and make other unlimited restricted payments and investments so long as (1) no event of default or borrowing base deficiency exists; (2) our total leverage ratio is 1.5 to 1 or lower; and (3) availability under the Bank Credit Agreement is at least 20% of the borrowing base.

As part of our Fall 2022 semiannual borrowing base redetermination, the borrowing base and lender commitments for our Bank Credit Agreement were reaffirmed at $750 million, with our next scheduled redetermination around May 1, 2023.

On January 20, 2023, we entered into a Third Amendment to the Bank Credit Agreement, targeted at providing us the ability to elect to make interest payments on certain SOFR loans on a weekly basis.

The Bank Credit Agreement 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 certain exceptions to such limitations, as specified in the Bank Credit Agreement. Our Bank Credit Agreement required certain minimum commodity hedge levels in connection with our emergence from bankruptcy; however, these conditions were met as of December 31, 2020, and we currently have no ongoing hedging requirements under the Bank Credit Agreement.

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

- A Consolidated Total Debt to Consolidated EBITDAX covenant (as defined in the Bank Credit Agreement), 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 1.0.

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, 2022, our ratio of consolidated total debt to consolidated EBITDAX was 0.05 to 1.0 (with a maximum permitted ratio of 3.5 to 1.0) and our current ratio was 2.70 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 22, 2023, 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 and amendments thereto, each of which is filed as an exhibit to our periodic reports filed with the Securities and Exchange Commission ("SEC"). The Second Amendment to the Credit Agreement, which is attached as Exhibit 10(d) to the Form 10-Q filed on May 6, 2022, contains the full text of the current version of the Bank Credit Agreement inclusive of all changes made by virtue of both the First and Second Amendments thereto.

Commitments, Obligations and Off-Balance Sheet Arrangements. We incur numerous contractual commitments in the ordinary course of business including debt service requirements, operating leases, purchase obligations, and asset retirement obligations. Our operating leases primarily consist of our office leases. Our purchase obligations represent future cash commitments primarily for purchase contracts for CO_2 captured from industrial sources, CO_2 processing fees, transportation agreements and well-related costs. Our off-balance sheet arrangements include obligations for various development and exploratory expenditures that arise from our normal oil and gas or CCUS capital expenditure program or from other transactions common to our industry, none of which are recorded on our balance sheet. During 2022, we entered into storage contracts to secure rights to underground pore space in anticipation of future CCUS operations. Noncancelable commitments under those contracts total $4 million. 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. Certain of these capital spending plans are further described in *2023 Plans and Capital Budget* above. 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, 2022. The most material of these commitments within the next 12 months include:

- Approximately $52.0 million under contracts for the purchase of CO_2 captured from industrial sources and for processing fees related to our overriding royalty interest in the CO_2 at LaBarge Field, both of which are used in our tertiary recovery activities, assuming a $75 per Bbl NYMEX oil price. The commitment level declines in 2023 and again in 2028 due to the expiration of the current term of certain industrial-CO_2 purchase commitments (see Note 14, *Commitments and Contingencies*, to the consolidated financial statements for further discussion); and
- Approximately $6 million in 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 May 4, 2027, and of which \$29.0 million of borrowings and \$10.1 million of letters of credit were outstanding as of December 31, 2022; 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. Oil prices and cash flow are highly impacted by worldwide oil supply and fluctuations in demand due to economic activity, which volatility we attempt to offset to some extent with our hedging program. The variability of proceeds from the sale of our production is partially offset by similar directional variances in certain expenses, including a portion of our lease operating expenses and production taxes, as these expenses correlate to some degree with changes in oil prices.

FINANCIAL OVERVIEW OF TERTIARY OPERATIONS

Our tertiary operations represent a significant portion of our overall operations. 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 23 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). For certain fields such as those in CCA, we estimate it could take up to 18 months or longer for a tertiary production response to occur. 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. 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
In thousands, except per-share data	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Financial results				
Net income (loss)(1)	$ 480,160	$ 56,002	$ (50,658)	$ (1,432,578)
Net income (loss) per common share – basic(1)	9.34	1.10	(1.01)	(2.89)
Net income (loss) per common share – diluted(1)	8.83	1.04	(1.01)	(2.89)
Net cash provided by operating activities	520,745	317,158	40,326	113,408

(1) Includes a pre-tax full cost pool ceiling test write-down of our oil and natural gas properties of $14.4 million for the year ended December 31, 2021, $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 operating results and statistics for each of the last three years are included in the following table.

In thousands, except per-unit data	Year Ended December 31, 2022	2021	2020
Average daily sales volumes			
Bbls/d	45,302	47,281	49,828
Mcf/d	9,038	8,933	7,938
BOE/d	46,809	48,770	51,151
Oil and natural gas sales			
Oil sales	$ 1,559,111	$ 1,148,022	$ 689,020
Natural gas sales	19,571	11,933	4,189
Total oil and natural gas sales	$ 1,578,682	$ 1,159,955	$ 693,209
Commodity derivative contracts(1)			
Receipt (payment) on settlements of commodity derivatives	$ (315,752)	$ (277,240)	$ 102,485
Noncash fair value losses on commodity derivatives	137,008	(75,744)	(62,355)
Commodity derivatives income (expense)	$ (178,744)	$ (352,984)	$ 40,130
Unit prices – excluding impact of derivative settlements			
Oil price per Bbl	$ 94.29	$ 66.52	$ 37.78
Natural gas price per Mcf	5.93	3.66	1.44
Unit prices – including impact of derivative settlements(1)			
Oil price per Bbl	$ 75.19	$ 50.46	$ 43.40
Natural gas price per Mcf	5.93	3.66	1.44
Oil and natural gas operating expenses			
Lease operating expenses	$ 502,409	$ 424,550	$ 351,505
Transportation and marketing expenses	20,112	28,817	37,759
Production and ad valorem taxes	128,302	88,468	53,708
Oil and natural gas operating revenues and expenses per BOE			
Oil and natural gas revenues	$ 92.40	$ 65.16	$ 37.03
Lease operating expenses	29.41	23.85	18.78
Transportation and marketing expenses	1.18	1.62	2.02
Production and ad valorem taxes	7.51	4.97	2.87
CO_2 – revenues and expenses			
CO_2 sales and transportation fees	$ 60,570	$ 44,175	$ 30,468
CO_2 operating and discovery expenses	(8,474)	(6,678)	(4,568)
CO_2 revenue and expenses, net	$ 52,096	$ 37,497	$ 25,900

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

Sales Volumes

Average daily sales volumes by area for 2022, 2021 and 2020, and for each of the quarters of 2022, are shown below:

	Average Daily Sales Volumes (BOE/d)						
	2022 Quarters				Year Ended December 31,		
Operating Area	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	2022	2021	2020
Tertiary oil sales volumes							
Gulf Coast region							
Delhi	2,675	2,478	2,557	2,528	2,559	2,861	3,419
Hastings	4,430	4,304	4,211	4,198	4,285	4,317	4,755
Heidelberg	3,653	3,528	3,571	3,670	3,605	3,921	4,297
Oyster Bayou	3,745	3,423	3,490	3,417	3,518	3,833	3,818
Tinsley	3,015	3,050	3,133	2,248	2,860	3,405	3,959
Other(1)	5,498	5,422	5,541	5,652	5,529	5,969	6,427
Total Gulf Coast region	23,016	22,205	22,503	21,713	22,356	24,306	26,675
Rocky Mountain region							
Bell Creek	4,474	4,122	3,975	3,767	4,082	4,416	5,518
Wind River Basin	2,517	2,703	3,121	3,726	3,020	2,019	—
Other(2)	2,229	2,361	2,759	2,824	2,546	2,040	1,942
Total Rocky Mountain region	9,220	9,186	9,855	10,317	9,648	8,475	7,460
Total tertiary oil sales volumes	32,236	31,391	32,358	32,030	32,004	32,781	34,135
Non-tertiary oil and gas sales volumes							
Gulf Coast region							
Total Gulf Coast region	3,630	3,566	3,727	3,666	3,647	3,683	3,807
Rocky Mountain region							
Cedar Creek Anticline	9,721	10,224	9,593	9,366	9,725	11,008	11,985
Other(3)	1,338	1,380	1,431	1,579	1,433	1,298	1,030
Total Rocky Mountain region	11,059	11,604	11,024	10,945	11,158	12,306	13,015
Total non-tertiary sales volumes	14,689	15,170	14,751	14,611	14,805	15,989	16,822
Total continuing sales volumes	46,925	46,561	47,109	46,641	46,809	48,770	50,957
Property sales							
Gulf Coast Working Interests Sale(4)	—	—	—	—	—	—	194
Total sales volumes	46,925	46,561	47,109	46,641	46,809	48,770	51,151

(1) Includes Brookhaven, Cranfield, Eucutta, Little Creek, Mallalieu, Martinville, McComb, Soso and West Yellow Creek fields.
(2) Includes Salt Creek and Grieve fields.
(3) Includes non-tertiary sales volumes from Wind River Basin, as well as Hartzog Draw and Bell Creek fields.
(4) Includes non-tertiary sales related to the March 2020 sale of 50% of our working interests in Webster, Thompson, Manvel, and East Hastings fields (the "Gulf Coast Working Interests Sale").

Total sales volumes during 2022 averaged 46,809 BOE/d, including 32,004 Bbls/d from tertiary properties and 14,805 BOE/d from non-tertiary properties. This total sales volume represents a decrease of 1,961 BOE/d (4%) compared to 2021 total sales volumes. The year-over-year decline was primarily attributable to natural field declines associated with low levels of development spending in recent years (excluding new CO_2 EOR development at CCA), partially offset by increased production at Wind River Basin, which was acquired in March 2021, due both to the inclusion in 2022 of a full year of production as well as post-acquisition development activities, and increases at Grieve Field as a result of CO_2 injection response. Our production during 2022 was 97% oil, consistent with 2021 and 2020.

Based on our capital spending plans, we currently anticipate 2023 average daily production will be between 46,000 BOE/d and 49,000 BOE/d, which, at its midpoint is 691 BOE/d higher than our average production in 2022. We anticipate first production from the CCA CO_2 EOR development in the second half of 2023, which is the primary driver for our expected production increase in 2023.

Oil and Natural Gas Revenues

Oil and natural gas revenues increased 36% between 2021 and 2022 and increased 67% between 2020 and 2021. 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, 2022 vs. 2021		Year Ended December 31, 2021 vs. 2020	
In thousands	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues
Change in oil and natural gas revenues due to:				
Decrease in production	$ (46,646)	(4)%	$ (34,069)	(5)%
Increase in commodity prices	465,373	40 %	500,815	72 %
Total increase in oil and natural gas revenues	$ 418,727	36 %	$ 466,746	67 %

Excluding any impact of our commodity derivative contracts, our average net realized commodity prices and NYMEX differentials were as follows during 2022, 2021 and 2020:

	Year Ended December 31,		
	2022	2021	2020
Average net realized prices			
Oil price per Bbl	$ 94.29	$ 66.52	$ 37.78
Natural gas price per Mcf	5.93	3.66	1.44
Price per BOE	92.40	65.16	37.03
Average NYMEX differentials			
Gulf Coast region			
Oil per Bbl	$ (0.19)	$ (1.42)	$ (1.14)
Natural gas per Mcf	(0.08)	0.26	(0.14)
Rocky Mountain region			
Oil per Bbl	$ 0.02	$ (1.32)	$ (2.80)
Natural gas per Mcf	(0.87)	(0.27)	(1.36)
Total Company			
Oil per Bbl	$ (0.10)	$ (1.38)	$ (1.81)
Natural gas per Mcf	(0.58)	(0.05)	(0.69)

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 $0.19 per Bbl in 2022 and a negative $1.42 per Bbl during 2021. During 2022, the Company benefited from improved Light Louisiana

Sweet ("LLS") pricing for its Gulf Coast grades relative to NYMEX WTI prices. For our crude oil sold under LLS index prices, the LLS-to-NYMEX differential averaged a positive $2.25 per Bbl on a trade-month basis during 2022, compared to a positive $1.49 per Bbl differential during 2021.

Rocky Mountain Region. NYMEX oil differentials in the Rocky Mountain region averaged $0.02 per Bbl above NYMEX during 2022, compared to an average differential of $1.32 per Bbl below NYMEX in 2021. Differentials in the Rocky Mountain region generally fluctuate with regional supply and demand trends and 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.

CO_2 Revenues and Expenses

We sell a portion of the CO_2 we produce 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. CO_2 sales and transportation fees were $60.6 million during 2022, compared to $44.2 million during 2021. The increase from the prior-year period was primarily due to revenues received pursuant to a short-term contractual agreement that ended during the fourth quarter of 2022.

Oil Marketing Revenues and Purchases

In certain situations, we purchase and subsequently sell oil from third parties. We recognize the revenue received and the associated expenses incurred on these sales on a gross basis as "Oil marketing revenues" and "Oil marketing purchases" in our Consolidated Statements of Operations.

Commodity Derivative Contracts

We have routinely entered 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:

	Three Months Ended				
In thousands	March 31	June 30	September 30	December 31	Full Year
2022					
Payment on settlements of commodity derivatives	$ (93,057)	$ (127,959)	$ (55,780)	$ (38,956)	$ (315,752)
Noncash fair value gains (losses) on commodity derivatives	(99,662)	71,105	165,028	537	137,008
Commodity derivatives income (expense)	$ (192,719)	$ (56,854)	$ 109,248	$ (38,419)	$ (178,744)

	Three Months Ended				
In thousands	March 31	June 30	September 30	December 31	Full Year
2021					
Payment on settlements of commodity derivatives	$ (38,453)	$ (63,343)	$ (77,670)	$ (97,774)	$ (277,240)
Noncash fair value gains (losses) on commodity derivatives	(77,290)	(109,321)	35,925	74,942	(75,744)
Commodity derivatives expense	$ (115,743)	$ (172,664)	$ (41,745)	$ (22,832)	$ (352,984)

	Predecessor			Successor		
	Three Months Ended		Period from July 1 through September 18	Period from September 19 through September 30	Three Months Ended December 31	Full Year
In thousands	March 31	June 30				
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	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

Commodity derivatives income (expense) is comprised of (1) payments or receipts on settlements of commodity derivatives and (2) changes in the fair values of commodity derivatives. Changes in the fair values of commodity derivatives are due to the expiration of commodity derivative contracts and changes in oil futures prices since the prior period or subsequent to entering into new derivative agreements. During 2022, we paid $315.8 million upon expiration of commodity derivative contracts, compared to cash payments upon settlement of $277.2 million during 2021.

In order to provide a level of price protection to our oil production, we have hedged a portion of our estimated oil production through 2024 using NYMEX fixed-price swaps and costless collars. Upon emergence from bankruptcy in September 2020, we were required to hedge through mid-2022 at certain levels of estimated production under our post-emergence bank credit facility. Those hedges resulted in significant cash losses to us during 2021 and 2022 as oil prices subsequently improved beyond our hedged prices. We no longer have any hedging requirements under our bank credit facility; however, we plan to continue to hedge a portion of our production in order to provide a level of certainty in our cash flows. See Note 12, *Commodity Derivative Contracts*, to the consolidated financial statements for additional details of our outstanding commodity derivative contracts as of December 31, 2022, and *Market Risk Management* below for additional discussion. In addition, the following table summarizes our oil derivative contracts as of February 22, 2023:

		1H 2023	2H 2023	1H 2024	2H 2024
WTI NYMEX	Volumes Hedged (Bbls/d)	9,500	14,000	2,000	1,000
Fixed-Price Swaps	Weighted Average Swap Price	$76.65	$78.46	$75.21	$75.12
WTI NYMEX	Volumes Hedged (Bbls/d)	17,500	9,000	—	—
Collars	Weighted Average Floor / Ceiling Price	$69.71 / $100.42	$68.33 / $100.69	—	—
	Total Volumes Hedged (Bbls/d)	27,000	23,000	2,000	1,000

Based on current contracts in place and NYMEX oil futures prices as of February 22, 2023, which averaged approximately $74 per Bbl for the remainder of 2023, we currently expect that we would receive cash receipts of approximately $19 million during 2023 upon settlement of these contracts, the amount of which is primarily dependent upon fluctuations in future NYMEX oil prices in relation to the prices of our 2023 fixed-price swaps (which have a weighted average NYMEX oil price of $77.74 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
In thousands, except per-BOE data	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Total lease operating expenses	$ 502,409	$ 424,550	$ 101,234	$ 250,271
Total lease operating expenses per BOE	$ 29.41	$ 23.85	$ 19.90	$ 18.36

Total lease operating expenses were $502.4 million, or $29.41 per BOE, during 2022, compared to $424.6 million, or $23.85 per BOE, during 2021. The $77.9 million (18%) increase on an absolute-dollar basis was the result of a $22.6 million increase for special items and a $55.3 million increase due primarily to inflation and higher activity levels. The increase on a per BOE basis was further impacted by lower production in the current year period.

Special items driving the increase in year-over-year LOE include (1) a $16.1 million non-recurring benefit in 2021 resulting from compensation under certain of the Company's power agreements for power interruption during the severe winter storm in February 2021, (2) an additional $13.2 million of LOE in 2022 reflecting an entire 12 months' worth expenses from our March 2021 acquisition of Wind River Basin properties, offset in part by (3) a $6.7 million benefit in 2022 for an insurance reimbursement of for property damage costs incurred during 2013 at Delhi Field.

Lifting cost excluding the special items increased 13% in 2022 compared to 2021. Inflation and higher activity levels resulted in higher power and fuel costs ($19.6 million), workover costs ($13.6 million), labor costs ($8.2 million), and CO_2 purchase costs ($2.7 million), as well as other increases.

We currently expect lease operating expenses during 2023 to increase slightly from 2022 levels as a result of CO_2 cost increases (primarily due to a contractual price change under an existing industrial CO_2 contract), inflationary impacts to cost categories such as company and contract labor, and the absence in 2023 of the $6.7 million Delhi Field insurance reimbursement.

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 $20.1 million during 2022, compared to $28.8 million for the year ended December 31, 2021. The decrease between periods was primarily due to a change in the sales contracts of certain of our production, which reduced our transportation expense.

Taxes Other than Income

Taxes other than income, which includes production, ad valorem and franchise taxes, were $131.5 million during 2022, compared to $91.4 million for the year ended December 31, 2021. The increase between periods was primarily due to an increase in production taxes resulting from higher oil and natural gas revenues.

General and Administrative Expenses ("G&A")

	Successor			Predecessor
In thousands, except per-BOE data and employees	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Cash G&A costs	$ 66,125	$ 53,936	$ 11,258	$ 41,096
Stock-based compensation	16,055	25,322	8,212	4,111
Severance-related costs	—	—	—	3,315
G&A expenses	$ 82,180	$ 79,258	$ 19,470	$ 48,522
G&A per BOE				
Cash G&A costs	$ 3.87	$ 3.03	$ 2.21	$ 3.02
Stock-based compensation	0.94	1.42	1.62	0.30
Severance-related costs	—	—	—	0.24
G&A expenses	$ 4.81	$ 4.45	$ 3.83	$ 3.56
Employees as of period end	765	716	657	662

Our G&A expense on an absolute-dollar basis was $82.2 million during 2022, compared to $79.3 million during 2021. The 23% increase in our cash G&A expenses during 2022 was primarily associated with increased employee headcount and professional services while the decrease in stock-based compensation in 2022 is due to the absence in 2022 of expense associated with the 2021 vesting of performance-based equity awards which were granted in late 2020. Although the performance criteria for these performance-based equity awards were met in 2021, the shares underlying these awards are not currently outstanding as under the terms of these awards actual delivery of the shares is not scheduled to occur until after the end of the performance period, no earlier than December 4, 2023. We currently expect G&A expense to increase in 2023 due to the inclusion in 2023 of a full year of expense associated with employees hired in 2022, additional headcount increases anticipated during 2023, and the cumulative expense for long-term equity incentive awards, with 2023 being the third full year of expense following emergence. A significant portion of the Company's planned headcount additions in 2023 are related to the Company's expanding CCUS activities. We currently expect our stock-based compensation to range between $22 million and $26 million in 2023.

Interest and Financing Expenses

	Successor			Predecessor
In thousands, except per-BOE data and interest rates	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Cash interest(1)	$ 5,266	$ 5,992	$ 2,277	$ 108,824
Less: interest not reflected as expense for financial reporting purposes(2)	—	—	—	(49,243)
Noncash interest expense	2,996	2,740	799	2,439
Amortization of debt discount(3)	—	—	—	9,132
Less: capitalized interest	(4,237)	(4,585)	(1,261)	(22,885)
Interest expense, net	$ 4,025	$ 4,147	$ 1,815	$ 48,267
Interest expense, net per BOE	$ 0.24	$ 0.23	$ 0.36	$ 3.54
Average debt principal outstanding(4)	$ 29,992	$ 84,970	$ 123,120	$ 1,767,605
Average cash interest rate(5)	6.6 %	4.1 %	1.3 %	6.1 %

(1) Cash interest during the 2020 Predecessor period includes the portion of interest on certain debt instruments accounted for as a reduction of debt for GAAP financial reporting purposes in accordance with Financial Accounting Standards Board Codification ("FASC") 470-60, *Troubled Debt Restructuring by Debtors*. Includes commitment fees paid on the Company's bank credit facility but excludes debt issue costs.

(2) The portion of interest treated as a reduction of debt during the 2020 Predecessor period 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"). 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 July 30, 2020 (the "Petition Date").

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

(4) For the 2020 period, excludes debt discounts related to the Predecessor's 7¾% Senior Secured Notes and 2024 Convertible Notes.

(5) Excludes commitment fees paid on the Company's bank credit facility and debt issue costs.

Cash interest was $5.3 million during 2022, compared to $6.0 million for the year ended December 31, 2021. The decrease between periods was primarily due to a decrease in the average debt principal outstanding.

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

	Successor			Predecessor
In thousands, except per-BOE data	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Oil and natural gas properties	$ 121,918	$ 119,997	$ 37,188	$ 104,495
CO_2 properties, pipelines, plants and other property and equipment	26,118	30,643	8,624	44,939
Accelerated depreciation charge(1)	3,392	—	—	39,159
Total DD&A	$ 151,428	$ 150,640	$ 45,812	$ 188,593
DD&A per BOE				
Oil and natural gas properties	$ 7.14	$ 6.74	$ 7.31	$ 7.66
CO_2 properties, pipelines, plants and other property and equipment	1.52	1.72	1.69	3.30
Accelerated depreciation charge(1)	0.20	—	—	2.87
Total DD&A cost per BOE	$ 8.86	$ 8.46	$ 9.00	$ 13.83
Write-down of oil and natural gas properties	$ —	$ 14,377	$ 1,006	$ 996,658

(1) Accelerated depreciation in 2021 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 $151.4 million during 2022, compared to $150.6 million for the year ended December 31, 2021. The 1% increase during 2022 compared to the 2021 period was primarily due to an accelerated depreciation charge. The slight increase related to oil and natural gas properties is the result of an increase in the accretion of our asset retirement obligations, largely offset by a lower depletion rate from an increase in our estimate of proved reserves between the periods based on higher commodity pricing. Our oil and natural gas properties depletion rate was $7.69 per BOE during the fourth quarter of 2022. We expect DD&A expense will be higher subsequent to the initial booking of proved reserves at our new CCA CO_2 flood, which we currently estimate will occur during 2023.

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 prices for each month during a 12-month rolling period prior to the end of a particular reporting period. We recognized a full cost pool ceiling test write-down of $14.4 million during the first quarter of 2021, with first-day-of-the-month NYMEX oil prices for the preceding 12 months averaging $36.40 per Bbl, after adjustments for market differentials and transportation expenses by field. The write-down was primarily a result of the March 2021 acquisition of Wyoming property interests (see Note 3, *Acquisition and Divestitures*) which was recorded based on a valuation that utilized NYMEX strip oil prices at the acquisition date, which were significantly higher than the average first-day-of-the-month NYMEX oil prices used to value the cost ceiling.

2020 Reorganization Items, Net

"Reorganization items, net" in our Consolidated Statements of Operations for the 2020 Predecessor period included (i) expenses incurred during the Company's "prepackaged" voluntary bankruptcy 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. Professional service provider charges associated with our restructuring that were incurred outside of this period (before the Petition Date and after the Emergence Date) were recorded in "Other expenses" in our Consolidated Statements of Operations.

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
Debtor-in-possession credit agreement fees	3,107
Acceleration of Predecessor stock compensation expense	4,601
Total reorganization items, net	$ 849,980

Other Expenses

Other expenses totaled $16.3 million during 2022 and primarily includes $4.9 million related to CCUS, a $3.9 million accrual for a preliminarily assessed civil penalty proposed by the Pipeline and Hazardous Materials Safety Administration of the U.S. Department of Transportation in a Notice of Probable Violation (see Item 3, *Legal Proceedings – Notice of Probable Violation from Pipeline and Hazardous Materials Safety Administration ("PHMSA") Regarding Delta-Tinsley CO_2 Pipeline Failure*), and $3.7 million related to plant operating expenses. Other expenses totaled $10.8 million for the year ended December 31, 2021 and primarily includes plant operating expenses, litigation accruals and noncash fair value adjustments for contingent consideration payments related to our March 2021 Wind River Basin CO_2 EOR field acquisition, slightly offset by insurance reimbursements for previously-incurred costs associated with the February 2020 Delta-Tinsley CO_2 pipeline repair.

Income Taxes

In thousands, except per-BOE amounts and tax rates	Successor Year Ended Dec. 31, 2022	Successor Year Ended Dec. 31, 2021	Successor Period from Sept. 19, 2020 through Dec. 31, 2020	Predeccesor Period from Jan. 1, 2020 through Sept. 18, 2020
Current income tax expense (benefit)	$ 5,363	$ 403	$ 30	$ (7,260)
Deferred income tax expense (benefit)	69,481	364	(2,556)	(408,869)
Total income tax expense (benefit)	$ 74,844	$ 767	$ (2,526)	$ (416,129)
Average income tax expense (benefit) per BOE	$ 4.38	$ 0.04	$ (0.49)	$ (30.52)
Effective tax rate	13.5 %	1.4 %	4.7 %	22.5 %
Total net deferred tax liability	$ 71,120	$ 1,638	$ 1,274	$ —

Our income tax provisions were based on an estimated combined federal and state statutory tax rate of approximately 25% for 2022, 2021 and 2020. Our effective tax rate for 2022 was lower than our estimated statutory rate, primarily due to the reversal of the valuation allowance on our federal and certain state deferred tax assets.

We make estimates and judgements in determining our income tax expense for financial reporting purposes. These estimates and judgements 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. Significant judgment is required in estimating valuation allowances, and in making this determination we consider all available positive and negative evidence and make certain assumptions. The realization of a deferred tax asset ultimately depends on the existence of sufficient taxable income in the applicable carryback or carryforward periods. In our assessment, we consider the nature, frequency, and severity of current and cumulative losses, as well as historical and forecasted financial results, the overall business environment, our industry's historic cyclicality, the reversal of existing deferred tax assets and liabilities, and tax planning strategies.

We assess the valuation allowance recorded on our deferred tax assets on a quarterly basis. At December 31, 2021 we had a $125.5 million valuation allowance recorded against our federal and certain state deferred tax assets. This valuation allowance was initially recorded in September 2020 after the application of fresh start accounting, as (1) the tax basis of our assets, primarily our oil and gas properties, was in excess of the carrying value, as adjusted for fresh start accounting and (2) our historical pre-tax income reflected a three-year cumulative loss primarily due to ceiling test write-downs and reorganization items that were recorded in 2020. While we continue to be in a cumulative three-year-loss position through 2022, we initially determined on March 31, 2022, that there was sufficient positive evidence, primarily related to a substantial increase in worldwide oil prices and taxable income generated from future reversals of existing taxable temporary differences, to conclude that our federal and certain state deferred tax assets are more likely than not to be realized. Accordingly, we reversed $51.4 million and $14.8 million of our federal and state valuation allowances during the year ended December 31, 2022, respectively. We continue to maintain a valuation allowance of $59.2 million for certain state tax benefits that we currently do not expect to realize before their expiration.

We have $0.6 million of alternative minimum tax credits, which under the Tax Cut and Jobs Act will be refunded in 2023 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 2019 have lapsed and therefore are not subject to examination by respective taxing authorities. Our estimated annual effective tax rate for 2023 is expected to be approximately 25% with current taxes anticipated to represent 5% to 10% of total taxes.

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 significant individual components is discussed above.

	Year Ended December 31,		
Per-BOE data	2022	2021	2020
Oil and natural gas revenues	$ 92.40	$ 65.16	$ 37.03
Receipt (payment) on settlements of commodity derivatives	(18.48)	(15.57)	5.47
Lease operating expenses	(29.41)	(23.85)	(18.78)
Production and ad valorem taxes	(7.51)	(4.97)	(2.87)
Transportation and marketing expenses	(1.18)	(1.62)	(2.02)
Production netback	35.82	19.15	18.83
CO_2 sales, net of operating and discovery expenses	3.05	2.10	1.39
General and administrative expenses[1]	(4.81)	(4.45)	(3.63)
Interest expense, net	(0.24)	(0.23)	(2.68)
Reorganization items settled in cash	—	—	(2.08)
Stock compensation and other	(0.53)	0.97	(0.38)
Changes in assets and liabilities relating to operations	(2.81)	0.28	(3.24)
Cash flows from operations	30.48	17.82	8.21
DD&A – excluding accelerated depreciation charge	(8.66)	(8.46)	(10.43)
DD&A – accelerated depreciation charge[2]	(0.20)	—	(2.09)
Write-down of oil and natural gas properties	—	(0.81)	(53.29)
Deferred income taxes	(4.07)	(0.02)	21.98
Gain on extinguishment of debt	—	—	1.01
Noncash fair value losses on commodity derivatives	8.02	(4.26)	(3.33)
Noncash reorganization items, net	—	—	(43.32)
Other noncash items	2.53	(1.12)	2.03
Net income (loss)	$ 28.10	$ 3.15	$ (79.23)

(1) General and administrative expenses include $15.3 million of performance stock-based compensation related to the full vesting of outstanding performance awards during the year ended December 31, 2021, resulting in a significant non-recurring expense, which if excluded, would have caused these expenses to average $3.60 per BOE.

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

MARKET RISK MANAGEMENT

Debt and Interest Rate Sensitivity

At December 31, 2022, we had $29.0 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, 2022:

In thousands	2022-2026	2027	Total	Fair Value
Variable rate debt				
Senior Secured Bank Credit Facility (weighted average interest rate of 9.0% at December 31, 2022)	$ —	$ 29,000	$ 29,000	$ 29,000

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. Over the last few years, these contracts have consisted of costless collars and fixed-price swaps. The production that we hedge has varied from year to year depending on our levels of debt, financial strength, expectation of future commodity prices, and occasionally requirements under our bank credit facility. We currently have no hedging requirements under our Bank Credit Agreement. In order to provide a level of price protection to our oil production, we have hedged a portion of our estimated oil production through 2024 using NYMEX fixed-price swaps and costless collars. Depending on market conditions, we may continue to add to our existing 2023 and 2024 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.

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 are charged to earnings instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings.

At December 31, 2022, our commodity derivative contracts were recorded at their fair value, which was a net asset of $2.5 million, a $137.0 million change from the $134.5 million net liability recorded at December 31, 2021. This change is related to the expiration of commodity derivative contracts during 2022, new commodity derivative contracts entered into during 2022 for future periods, and to the changes in oil futures prices between December 31, 2021 and 2022.

Commodity Derivative Sensitivity Analysis

Based on NYMEX oil futures prices and derivative contracts in place as of December 31, 2022, 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, 2022	$	(3,735)
10% increase in prices		(38,241)
10% decrease in prices		32,685

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 on 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 ESTIMATES

The preparation of financial statements in accordance with generally accepted accounting principles requires that we make certain estimates and judgments. 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.

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 4.8% 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 2022 oil and natural gas property DD&A rate from $7.69 per BOE to approximately $7.38 per BOE, and a 5% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $8.02 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 CO_2 capital 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 $93.02 at December 31, 2022, $63.86 at December 31, 2021, $35.84 at December 31, 2020, and $40.08 at September 18, 2020. We recognized a full cost pool ceiling test write-down of $14.4 million during the first quarter of 2021, with first-day-of-the-month NYMEX oil prices for the preceding 12 months averaging $36.40 per Bbl, after adjustments for market differentials and transportation expenses by field. The write-down was primarily a result of the March 2021 acquisition of Wyoming property interests (see Note 3, *Acquisition and Divestitures*) which was recorded based on a valuation that utilized NYMEX strip oil prices at the acquisition date, which were significantly higher than the average first-day-of-the-month NYMEX oil prices used to value the cost ceiling. Primarily as a result of commodity price declines during 2020, 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 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. 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).

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 $32.8 million of tertiary injection costs associated with our tertiary projects during 2022, $7.6 million during 2021, $2.3 million 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.

CCUS Asset Allocation

The Company has entered into numerous storage agreements that provide a right to inject CO_2 into the pore space (sub-surface) and access the surface above the pore space. The agreements do not give the Company ownership of the land, but instead require payment of annual fees for these rights. Denbury recognizes the rights to the surface and subsurface as intangible assets, and will capitalize and depreciate the related contract costs. Denbury will allocate payments between the surface and the subsurface based upon the fair value of surface assets versus subsurface assets. The surface assets will be depreciated over the period during which the Company has access to the land and the subsurface assets will be amortized based on utilization of available pore space.

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, 2022, we had tax valuation allowances totaling $59.2 million to reduce the carrying value of our state deferred tax assets. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized. Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes our cumulative loss position, the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies and judgment is required in considering the relative weight of negative and positive evidence. Significant judgment is involved in this determination as we are required to make assumptions about forecasted commodity prices and economics in the oil and gas industry that may impact our ability to generate future earnings. Such estimates are inherently subjective. Changes in judgment regarding future realization of deferred tax assets may result in a reversal of all or a portion of the valuation allowance in the period that determination is made, and our net income during that period would benefit from a lower effective tax rate. A 1% increase in our statutory tax rate would have increased our calculated income tax expense (benefit) by approximately $5.6 million for the year ended December 31, 2022, and $0.6 million for the year ended December 31, 2021.

Fair Value Estimates

The FASC defines fair value, establishes a framework for measuring fair value and requires disclosures about fair value measurements. The FASC 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);
- allocation of the purchase price to assets acquired and liabilities assumed in acquisitions;
- 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, CCUS storage sites and related costs, 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 and future CCUS revenues. 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 oil and gas 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. Significant assumptions impacting expected future CCUS undiscounted net cash flows include projection of future CO_2 volumes available for transportation and storage and the development and operating costs of our storage sites. We performed a qualitative assessment as of December 31, 2022 and determined there were no material changes to our key cash flow assumptions and no triggering events since September 18, 2020 when the Company's assets were revalued in fresh start accounting; therefore, no impairment test was performed for the fourth quarter of 2022.

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, 2022 would increase our estimated payments on our crude oil derivative contracts by $35 million, and a 10% decrease in NYMEX oil futures prices would reduce our estimated payments by $36 million.

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.

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.

FORWARD-LOOKING INFORMATION

The data and/or statements contained in this Annual Report on Form 10-K, particularly statements found in "Management's Discussion and Analysis of Financial Condition and Results of Operations," that are not historical facts, 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, and include, but are not limited to: possible or assumed future results of operations, cash flows, production and capital expenditures; goals and predictions as to the Company's future carbon capture, use and storage ("CCUS") activities; and assumptions as to oil markets or general economic conditions.

Such forward-looking statements may be or may concern, among other things, the level and volatility of posted or realized oil prices; the adequacy of our liquidity sources to support our future activities; statements or predictions related to the ultimate timing and financial impact of our proposed CCUS arrangements, including the estimated emissions storage capacity of storage sites, predictions of long-term cumulative capital investments in CCUS, the volumes of CO_2 emissions we estimate can be transported and stored, along with the timing of receipt of first revenues from storage of CO_2; our projected production levels, oil and natural gas revenues or oilfield costs, the impact of supply chain issues and inflation on our results of operations; current or future expectations or estimations of our cash flows or the impact of changes in commodity prices on cash flows; availability, terms and financial statement and cash settlement impact of commodity derivative contracts or their predicted downside cash flow protection; forecasted drilling activity or methods, including the timing and location thereof; anticipated timing of commencement of CO_2 injections in particular fields or areas, or initial production responses in tertiary flooding projects; other development activities, finding costs, interpretation or prediction of formation details, 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 changes or proposed changes in Federal or state tax or environmental laws or regulations or in any future regulation of CO_2 pipelines; the outcomes of any pending litigation or regulatory proceedings; and overall worldwide or U.S. 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 that could significantly and adversely be affected by various factors discussed below, along with currently unknowable events beyond our control. 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 from current projections are fluctuations in worldwide or U.S. oil prices, especially in light of existing economic or geopolitical events such as the war in Ukraine; widespread inflation in economies across the world; future decisions as to production levels and/or pricing by OPEC; as to our CCUS activities, the successful completion of technical and feasibility evaluations, the raising of funds sufficient to build and operate add-on or new facilities, the pace of finalization of CCUS arrangements; and the receipt of required regulatory approval or classifications; success of our risk management techniques; the uncertainty of drilling results and reserve estimates; operating hazards and remediation costs; disruption of operations and damages from cybersecurity breaches, or from well incidents, climate events such as hurricanes, tropical storms, floods, or other natural occurrences; conditions in the worldwide financial, trade currency and credit markets; the risks and uncertainties inherent in oil and gas drilling and production activities; and the risks and uncertainties set forth from time to time in this or our other periodic public reports, other 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

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 sheets of Denbury Inc. and its subsidiaries (Successor) (the "Company") as of December 31, 2022 and 2021, and the related consolidated statements of operations, of changes in stockholders' equity and of cash flows for the years then ended, and for the period from September 19, 2020 to 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for the years then ended, and 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, 2022, 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 audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits 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 audits 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 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. 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 audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide 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 $1,931.7 million as of December 31, 2022, and depletion, depreciation and amortization (DD&A) expense was $151.4 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. 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 depletion, depreciation and amortization calculation 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 the depletion, depreciation and amortization 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 depletion, depreciation and amortization calculation. 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.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
February 23, 2023

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 statements of operations, of changes in stockholders' equity and of cash flows of Denbury Resources Inc. and its subsidiaries (Predecessor) (the "Company") for the period from January 1, 2020 to September 18, 2020, 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 results of operations and cash flows of the Company for the period from January 1, 2020 to September 18, 2020 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.

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.

/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)

	December 31, 2022	December 31, 2021
Assets		
Current assets		
Cash and cash equivalents	$ 521	$ 3,671
Accrued production receivable	144,277	143,365
Trade and other receivables, net	27,343	19,270
Derivative assets	15,517	—
Prepaids	18,572	9,099
Total current assets	206,230	175,405
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	1,414,779	1,109,011
Unevaluated properties	240,435	112,169
CO_2 properties	190,985	183,369
Pipelines	220,125	224,394
CCUS storage sites and related assets	64,971	—
Other property and equipment	107,133	93,950
Less accumulated depletion, depreciation, amortization and impairment	(306,743)	(181,393)
Net property and equipment	1,931,685	1,541,500
Operating lease right-of-use assets	18,017	19,502
Intangible assets, net	79,128	88,248
Restricted cash for future asset retirement obligations	47,359	46,673
Other assets	45,080	31,625
Total assets	$ 2,327,499	$ 1,902,953
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 248,800	$ 191,598
Oil and gas production payable	80,368	75,899
Derivative liabilities	13,018	134,509
Operating lease liabilities	4,676	4,677
Total current liabilities	346,862	406,683
Long-term liabilities		
Long-term debt, net of current portion	29,000	35,000
Asset retirement obligations	315,942	284,238
Deferred tax liabilities, net	71,120	1,638
Operating lease liabilities	15,431	17,094
Other liabilities	16,527	22,910
Total long-term liabilities	448,020	360,880
Commitments and contingencies (Note 14)		
Stockholders' equity		
Preferred stock, $0.001 par value, 50,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $0.001 par value, 250,000,000 shares authorized; 49,814,874 and 50,193,656 shares issued, respectively	50	50
Paid-in capital in excess of par	1,047,063	1,129,996
Retained earnings	485,504	5,344
Total stockholders' equity	1,532,617	1,135,390
Total liabilities and stockholders' equity	$ 2,327,499	$ 1,902,953

See accompanying Notes to Consolidated Financial Statements.

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

	Successor			Predecessor
	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Revenues and other income				
Oil, natural gas, and related product sales	$ 1,578,682	$ 1,159,955	$ 201,108	$ 492,101
CO_2 sales and transportation fees	60,570	44,175	9,419	21,049
Oil marketing revenues	65,093	38,742	5,376	8,543
Other income	10,314	15,288	4,697	8,419
Total revenues and other income	1,714,659	1,258,160	220,600	530,112
Expenses				
Lease operating expenses	502,409	424,550	101,234	250,271
Transportation and marketing expenses	20,112	28,817	10,595	27,164
CO_2 operating and discovery expenses	8,474	6,678	1,976	2,592
Taxes other than income	131,502	91,390	16,584	43,531
Oil marketing purchases	64,497	37,734	5,318	8,399
General and administrative expenses	82,180	79,258	19,470	48,522
Interest, net of amounts capitalized of $4,237, $4,585, $1,261, and $22,885, respectively	4,025	4,147	1,815	48,267
Depletion, depreciation, and amortization	151,428	150,640	45,812	188,593
Commodity derivatives expense (income)	178,744	352,984	61,902	(102,032)
Gain on debt extinguishment	—	—	—	(18,994)
Write-down of oil and natural gas properties	—	14,377	1,006	996,658
Reorganization items, net	—	—	—	849,980
Other expenses	16,284	10,816	8,072	35,868
Total expenses	1,159,655	1,201,391	273,784	2,378,819
Income (loss) before income taxes	555,004	56,769	(53,184)	(1,848,707)
Income tax provision (benefit)	74,844	767	(2,526)	(416,129)
Net income (loss)	$ 480,160	$ 56,002	$ (50,658)	$ (1,432,578)
Net income (loss) per common share				
Basic	$ 9.34	$ 1.10	$ (1.01)	$ (2.89)
Diluted	$ 8.83	$ 1.04	$ (1.01)	$ (2.89)
Weighted average common shares outstanding				
Basic	51,427	50,918	50,000	495,560
Diluted	54,355	53,818	50,000	495,560

See accompanying Notes to Consolidated Financial Statements.

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

	Successor			Predecessor
	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Cash flows from operating activities				
Net income (loss)	$ 480,160	$ 56,002	$ (50,658)	$ (1,432,578)
Adjustments to reconcile net income (loss) to cash flows from operating activities				
Noncash reorganization items, net	—	—	—	810,909
Depletion, depreciation, and amortization	151,428	150,640	45,812	188,593
Write-down of oil and natural gas properties	—	14,377	1,006	996,658
Deferred income taxes	69,481	364	(2,556)	(408,869)
Stock-based compensation	16,055	25,322	8,212	4,111
Commodity derivatives expense (income)	178,744	352,984	61,902	(102,032)
Receipt (payment) on settlements of commodity derivatives	(315,752)	(277,240)	21,089	81,396
Gain on debt extinguishment	—	—	—	(18,994)
Debt issuance costs and discounts	2,996	2,740	799	11,571
Gain from asset sales and other	(1,232)	(10,609)	(3,546)	(6,723)
Other, net	(13,198)	(2,465)	1,197	7,162
Changes in assets and liabilities, net of effects from acquisitions				
Accrued production receivable	(911)	(51,944)	21,411	26,575
Trade and other receivables	(8,241)	(284)	15,567	(22,343)
Other current and long-term assets	(9,659)	10,390	(1,795)	743
Accounts payable and accrued liabilities	964	28,500	(67,167)	(16,102)
Oil and natural gas production payable	4,469	29,351	(6,912)	(6,792)
Asset retirement obligation settlements	(34,260)	(10,185)	(3,439)	(2,465)
Other liabilities	(299)	(785)	(596)	2,588
Net cash provided by operating activities	520,745	317,158	40,326	113,408
Cash flows from investing activities				
Oil and natural gas capital expenditures	(317,094)	(150,911)	(17,964)	(99,582)
CCUS storage sites and related capital expenditures	(59,880)	—	—	—
Acquisitions of oil and natural gas properties	(976)	(10,979)	(82)	—
Pipeline capital expenditures	(23,478)	(69,223)	(618)	(11,601)
Net proceeds from sales of oil and natural gas properties and equipment	237	19,053	938	41,322
Equity investment	(10,218)	—	—	—
Other	(16,521)	9,128	15,842	12,747
Net cash used in investing activities	(427,930)	(202,932)	(1,884)	(57,114)
Cash flows from financing activities				
Bank repayments	(1,015,000)	(933,000)	(190,000)	(551,000)
Bank borrowings	1,009,000	898,000	120,000	691,000
Common stock repurchase program	(100,028)	—	—	—
Pipeline financing and capital lease debt repayments	—	(68,008)	(22,938)	(51,792)
Interest payments treated as a reduction of debt	—	—	—	(46,417)
Cash paid in conjunction with debt repurchases	—	—	—	(14,171)
Other	10,749	(3,122)	1,630	(21,845)
Net cash provided by (used in) financing activities	(95,279)	(106,130)	(91,308)	5,775
Net increase (decrease) in cash, cash equivalents, and restricted cash	(2,464)	8,096	(52,866)	62,069
Cash, cash equivalents, and restricted cash at beginning of period	50,344	42,248	95,114	33,045
Cash, cash equivalents, and restricted cash at end of period	$ 47,880	$ 50,344	$ 42,248	$ 95,114

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)		
	Shares	Amount			Shares	Amount	Total Equity
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
Stock-based compensation	—	—	27,205	—	—	—	27,205
Tax withholding for stock compensation plans	—	—	(2,244)	—	—	—	(2,244)
Issued pursuant to exercise of warrants	193,657	—	759	—	—	—	759
Net income	—	—	—	56,002	—	—	56,002
Balance – December 31, 2021 (Successor)	50,193,656	50	1,129,996	5,344	—	—	1,135,390
Stock repurchase program	(1,615,356)	—	—	—	1,615,356	(100,028)	(100,028)
Net issued pursuant to stock compensation plans	152,955	—	—	—	—	—	—
Stock-based compensation	—	—	17,067	—	—	—	17,067
Retired Treasury Shares	—	(1)	(100,029)	—	(1,615,391)	100,030	—
Tax withholding for stock compensation plans	(35)	—	(937)	—	35	(2)	(939)
Employee stock purchase plan	7,604	—	561	—	—	—	561
Issued pursuant to exercise of warrants	1,076,050	1	405	—	—	—	406
Net income	—	—	—	480,160	—	—	480,160
Balance – December 31, 2022 (Successor)	49,814,874	$ 50	$ 1,047,063	$ 485,504	—	$ —	$ 1,532,617

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 in the Gulf Coast and Rocky Mountain regions of the United States. 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 extensive CO_2 pipeline infrastructure.

We adopted fresh start accounting upon emergence from voluntary reorganization under Chapter 11 of the Bankruptcy Code in September 2020 at which point we became a new entity for financial reporting purposes.

As a result of the application of fresh start accounting and the effects of the implementation of our Plan of Reorganization, the financial statements after September 18, 2020 may not be comparable to the financial statements prior to that date. Accordingly, "black-line" financial statements are presented to distinguish between the Predecessor and Successor companies. References to "Predecessor" refer to the Company for periods ended on or prior to September 18, 2020 and references to "Successor" refer to the Company for periods subsequent to September 18, 2020. See Note 2, *Fresh Start Accounting* for additional information on our bankruptcy proceedings and the impact of fresh start accounting on our consolidated financial statements.

2020 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"). 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. We have no remaining obligations related to this reorganization.

On the Emergence Date and pursuant to the terms of the Plan and the Confirmation Order, all outstanding obligations under Denbury's previously issued notes were fully extinguished, relieving approximately $2.1 billion in aggregate principal 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 "Bank Credit Agreement") with total aggregate commitments of $575 million;

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. Such charges 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 segregation of "Reorganization items, net" as a separate line in the 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.

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; (9) estimates made in determining the fair values for purchase price allocations; and (10) other estimates recorded as a result of the adoption of fresh start accounting (see Note 2, *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.

Business Segment Information

We have evaluated our organization and management of our business, as well as the information we use to make resource allocations, and have determined that we have one operating segment. Management measures financial performance for the Company as a whole and, at this time, does not assess performance of oil and gas operations separately from our emerging CCUS business. While we have been actively engaged in pursuing emerging CCUS business activities as a natural extension of our historic CO_2 EOR operations and CO_2 pipeline infrastructure, to date we do not have revenues associated with capturing, transporting and sequestering CO_2 emissions for dedicated storage and the expenses associated with these activities are immaterial to our consolidated financial statements.

We have recorded $65.0 million of CCUS assets on our Consolidated Balance Sheet as of December 31, 2022 and incurred $59.9 million of CCUS capital expenditures on our Consolidated Statement of Cash Flows for the year ended December 31, 2022, most of which is attributable to the development of CO_2 storage sites for future sequestration of captured industrial emissions.

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 and other income, total expenses, net income (loss), 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:

In thousands	December 31, 2022	December 31, 2021
Cash and cash equivalents	$ 521	$ 3,671
Restricted cash for future asset retirement obligations	47,359	46,673
Total cash, cash equivalents, and restricted cash shown in the Consolidated Statements of Cash Flows	$ 47,880	$ 50,344

Restricted cash for future asset retirement obligations in the table above consists of escrow accounts that are legally restricted for certain of our asset retirement obligation.

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. The costs capitalized, including production equipment and future development costs, are depleted 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.

Impairment of Unevaluated Oil and Natural Gas Properties. 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 coronavirus 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*).

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 CO_2 capital 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 $93.02 at December 31, 2022, $63.86 at December 31, 2021, $35.84 at December 31, 2020, and $40.08 at September 18, 2020. We did not recognize a full cost pool ceiling test write-down during the year ended December 31, 2022. During the year ended December 31, 2021, we recognized a $14.4 million full cost pool ceiling test write-down primarily as a result of the March 2021 acquisition of Wyoming property interests (see Note 3, *Acquisition and Divestitures*) which was recorded based on a valuation that utilized NYMEX strip oil prices at the acquisition date, which were significantly higher than the average first-day-of-the-month NYMEX oil prices used to value the cost ceiling. Primarily as a result of the commodity price declines during 2020, 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.

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 50 years.

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 are generally depreciated over a useful life of five years, furniture and fixtures over a life of ten years, and computer equipment and software are generally depreciated over a useful life of three 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 represent amounts assigned 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 $9.1 million during the year ended December 31, 2022, $9.1 million during the year ended December 31, 2021, $2.7 million during the Successor period September 19, 2020 through December 31, 2020 and $1.7 million for the Predecessor period January 1, 2020 through September 18, 2020. The following table summarizes the carrying value of our intangible assets as of December 31, 2022 and 2021:

In thousands	December 31, 2022	December 31, 2021
Long-term contracts to sell CO_2 to industrial customers	$ 97,943	$ 97,943
Other intangibles	2,179	2,179
Accumulated amortization	(20,994)	(11,874)
Net book value	$ 79,128	$ 88,248

As of December 31, 2022, our estimated amortization expense for our intangible assets subject to amortization over the next five years is as follows:

In thousands	
2023	$ 9,117
2024	9,117
2025	9,117
2026	9,117
2027	8,832

CCUS Storage Sites and Other Assets

Capitalized Costs. We capitalize costs that we incur to lease, acquire and develop storage sites for the injection of CO_2. These costs generally include, or are expected to include, expenditures for acquiring surface and subsurface rights; third-party acquisition costs; the acquisition of seismic data, permitting; drilling; facilities; environmental monitoring equipment for groundwater and storage site gas; engineering; capitalized interest; on-site road construction and other capital infrastructure costs. If it is determined that a storage site is no longer probable of being pursued, developed or utilized, all previously capitalized costs associated with that site are expensed.

Amortization. Our CCUS storage sites are currently in the development stage and not yet operational. Accordingly, we currently have no amortization of capitalized costs. Amortization of these costs will begin when CO_2 storage operations commence.

Investment in Project Development Company ("Clean Hydrogen Works") of Planned Louisiana Blue Hydrogen Ammonia Project. During 2022, we made a $10 million investment in the project development company of a planned blue hydrogen/ammonia multi-block facility, while also signing a definitive agreement for the transportation and storage of CO_2 for the first two blocks of the proposed plant. We have committed to invest another $10 million when certain milestones are achieved, currently expected to occur in 2023. The investment is included in "Other assets" in the Consolidated Balance Sheet as of December 31, 2022.

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, pipelines and CCUS assets, and also include long-term contracts to sell CO_2 to industrial customers.

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. 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. We did not record an impairment of long-lived assets during the year ended December 31, 2022 and 2021, the Successor Period from September 19, 2020 through December 31, 2020 or the Predecessor period from January 1, 2020 through September 18, 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 year ended December 31, 2022, two purchasers each accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (27%) and Hunt Crude Oil Supply Company (11%). For the year ended December 31, 2021, four purchasers each accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (28%), Hunt Crude Oil Supply Company (12%), Marathon Petroleum (11%) and Sunoco Inc. (11%), and for the Successor period September 19, 2020 through December 30, 2020, three purchasers each 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%). For the Predecessor period January 1, 2020 through September 18, 2020, three purchasers each 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%).

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. Basic weighted average common shares exclude shares of nonvested restricted stock (although nonvested restricted stock is issued and outstanding upon grant). As these restricted shares vest, they will be included in the shares outstanding used to calculated basic net income (loss) per common share. Restricted stock units and performance stock units are also excluded from basic weighted average common shares outstanding until the vesting date. Basic weighted average common shares during the year ended December 31, 2022 includes 1,784,474 performance-based and restricted stock units which were fully vested as of December 31, 2022; however, the shares underlying these awards are not included in shares currently issued or outstanding as actual delivery of the shares is not scheduled to occur until December 4, 2023.

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 periods include restricted stock, restricted stock units, performance stock units, shares to be issued under the employee stock purchase plan (“ESPP”) and series A and series B warrants, and during the Predecessor periods consisted of restricted stock, performance-based equity awards, and convertible senior notes.

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

	Successor			Predecessor
In thousands	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Weighted average common shares outstanding – basic	51,427	50,918	50,000	495,560
Effect of potentially dilutive securities				
Restricted stock, restricted stock units and performance stock units	622	762	—	—
Warrants	2,306	2,138	—	—
Weighted average common shares outstanding – diluted	54,355	53,818	50,000	495,560

For each of the periods from September 19, 2020 through December 31, 2020 (Successor) and from January 1, 2020 through September 18, 2020 (Predecessor), the weighted average common shares outstanding used to calculate basic earnings per share and diluted earnings per share were the same, since the Company generated a net loss during those periods. The weighted average diluted shares outstanding would have been 50.0 million for the period September 19, 2020 through December 31, 2020 and 584.4 million for the period January 1, 2020 through September 18, 2020, if the Company had recognized net income during those periods.

For purposes of calculating diluted weighted average common shares for the years ended December 31, 2022 and 2021, unvested restricted stock units, unvested restricted stock, unvested performance stock units, ESPP shares and unexercised warrants are included in the diluted shares computation using the treasury stock method.

The following outstanding securities were excluded from the computation of diluted net income (loss) per share for the year ended December 31, 2022, year ended December 31, 2021, and the period September 19, 2020 through December 31, 2020, as their effect would have been antidilutive, as of the respective dates:

In thousands	December 31, 2022	December 31, 2021	December 31, 2020
Restricted stock, restricted stock units and performance stock units	11	—	1,220
Warrants	—	—	5,526
Employee Stock Purchase Plan	—	—	—

For the period September 19, 2020 through December 31, 2020, the Company's restricted stock units and series A and series B warrants were antidilutive based on the Company's net loss position for the periods. At December 31, 2022, the Company had approximately 3.2 million warrants outstanding that can be exercised for shares of our common stock, at an exercise price of $32.59 per share for the 1.8 million series A warrants outstanding and at an exercise price of $35.41 per share for the 1.4 million series B warrants outstanding. The warrants may be exercised for cash or on a cashless basis. The series A warrants are exercisable until September 18, 2025, and the series B warrants are exercisable until September 18, 2023, at which time the warrants expire. Through December 31, 2022, 0.8 million series A warrants and 1.4 million series B warrants have been exercised for a total of 1.3 million shares, most of which were 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

Income Taxes. In December 2019, the Financial Accounting Standards Board issued Accounting Standards Update ("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. Effective January 1, 2021, we adopted ASU 2019-02. The implementation of this standard did not have a material impact on our consolidated financial statements and related footnote disclosures.

Note 2. Fresh Start Accounting

Fresh Start Accounting

Upon emergence from bankruptcy in 2020, we adopted 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, 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.

Reorganization Value Upon Emergence

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, net" in our Consolidated Statements of Operations includes (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. Professional service provider charges associated with our restructuring that were incurred outside of this period (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	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
Debtor-in-possession credit agreement fees	3,107
Acceleration of Predecessor stock compensation expense	4,601
Total reorganization items, net	$ 849,980

Valuation Process Upon Emergence

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 estimated 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 estimated 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.

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.

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 model. The Black-Scholes 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.

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

	As of September 18, 2020			
In thousands	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. Acquisition and Divestitures

Acquisition of Wyoming CO_2 EOR Fields

On March 3, 2021, we acquired a nearly 100% working interest (approximately 83% net revenue interest) in the Big Sand Draw and Beaver Creek EOR fields located in Wyoming from a subsidiary of Devon Energy Corporation, including surface facilities and a 46-mile CO_2 transportation pipeline to the acquired fields. The acquisition purchase price was $10.9 million (after final closing adjustments) plus two contingent $4 million cash payments if NYMEX WTI oil prices average at least $50 per Bbl during each of 2021 and 2022. We made the first contingent payment in January 2022 and the second $4 million payment in January 2023. The fair value of the contingent consideration on the acquisition date was $5.3 million, and as of December 31, 2022, the fair value of the contingent consideration recorded on our Consolidated Balance Sheets was $4 million. Fair value changes of $0.3 million and $2.4 million resulting from higher NYMEX WTI oil prices were recorded to “Other expenses” in our Consolidated Statements of Operations for the years ended December 31, 2022 and 2021, respectively.

The fair values allocated to our assets acquired and liabilities assumed for the acquisition were based on significant inputs not observable in the market and considered level 3 inputs. The fair value of the assets acquired and liabilities assumed was finalized during the third quarter of 2021, after consideration of final closing adjustments and evaluation of reserves and liabilities assumed.

The following table presents a summary of the fair value of assets acquired and liabilities assumed in the acquisition:

In thousands	
Consideration:	
Cash consideration	$ 10,906
Fair value of assets acquired and liabilities assumed:	
Proved oil and natural gas properties	60,101
Other property and equipment	1,685
Asset retirement obligations	(39,794)
Contingent consideration	(5,320)
Other liabilities	(5,766)
Fair value of net assets acquired	$ 10,906

Divestitures

Hartzog Draw Deep Mineral Rights

On June 30, 2021, we closed the sale of undeveloped, unconventional deep mineral rights in Hartzog Draw Field in Wyoming. The cash proceeds of $18 million were recorded to “Proved properties” in our Consolidated Balance Sheets. The proceeds reduced our full cost pool; therefore, no gain or loss was recorded on the transaction, and the sale had no impact on our production or proved reserves.

Houston Area Land Sales

During 2022 and 2021, we completed sales of a portion of certain non-producing surface acreage in the Houston area. We received cash proceeds of $1.4 million and $15.2 million from the sales and recognized $0.8 million and $10.3 million in gains to “Other income” in our Consolidated Statements of Operations for the years ended December 31, 2022 and 2021, respectively.

Gulf Coast Working Interests Sale

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 control (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 received within a month following product delivery, and for natural gas and NGL contracts, payment is generally received 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, in certain situations, the Company enters into marketing arrangements for the purchase and subsequent sale of crude oil from third parties. We recognize the revenue received and the associated expenses incurred on these sales on a gross basis, as “Oil marketing revenues” and “Oil marketing purchases” in our Consolidated Statements of Operations, since 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
In thousands	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Oil sales	$ 1,559,111	$ 1,148,022	$ 199,769	$ 489,251
Natural gas sales	19,571	11,933	1,339	2,850
CO_2 sales and transportation fees	60,570	44,175	9,419	21,049
Oil marketing revenues	65,093	38,742	5,376	8,543
Total revenues	$ 1,704,345	$ 1,242,872	$ 215,903	$ 521,693

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 13 years, with certain land leases having remaining terms up to 47 years. Leases with a term of 12 months or less are not recorded on our balance sheet. The table below reflects our operating lease right-of-use assets and operating lease liabilities, which primarily consist of our office leases:

In thousands	December 31, 2022	December 31, 2021
Operating leases		
Operating lease right-of-use assets	$ 18,017	$ 19,502
Operating lease liabilities – current	$ 4,676	$ 4,677
Operating lease liabilities – long-term	15,431	17,094
Total operating lease liabilities	$ 20,107	$ 21,771

The majority of our leases contain renewal options, typically exercisable at our sole discretion. The following table presents weighted average remaining lease terms and discount rates for our outstanding operating leases:

	December 31, 2022	December 31, 2021
Weighted average remaining lease term	4.5 years	5.2 years
Weighted average discount rate	5.7 %	5.4 %

We account for lease and nonlease components in a contract as a single lease component for all asset classes. 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. Variable lease costs represent additional payments in excess of our minimum base rental payments under our office space leases. 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	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Operating lease cost	General and administrative expenses	$ 5,532	$ 4,102	$ 872	$ 5,683
	Lease operating expenses	178	655	158	214
	CO_2 operating and discovery expenses	50	50	14	37
		$ 5,760	$ 4,807	$ 1,044	$ 5,934
Finance lease cost					
Amortization of right-of-use assets	Depletion, depreciation, and amortization	$ —	$ —	$ 3	$ 9
Interest on lease liabilities	Interest expense	—	—	1	3
Total finance lease cost		$ —	$ —	$ 4	$ 12
Variable lease cost		$ 758	$ 670	$ 258	$ 3,688
Sublease income	General and administrative expenses	$ —	$ —	$ 100	$ 2,584

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

	Successor			Predecessor
In thousands	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Cash paid for amounts included in the measurement of lease liabilities				
Operating cash flows from operating leases	$ 5,903	$ 2,830	$ 341	$ 7,341
Operating cash flows from interest on finance leases	—	—	1	3
Financing cash flows from finance leases	—	—	78	10
Right-of-use assets obtained in exchange for lease obligations				
Operating leases	2,270	2,683	19,902	1,049
Finance leases	—	—	—	162

The following table summarizes by year the maturities of our lease liabilities as of December 31, 2022:

In thousands	Operating Leases
2023	$ 5,702
2024	4,963
2025	4,974
2026	4,640
2027	1,786
Thereafter	1,023
Total minimum lease payments	23,088
Less: Amount representing interest	(2,981)
Present value of minimum lease liabilities	$ 20,107

Note 6. Asset Retirement Obligations

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

In thousands	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021
Beginning asset retirement obligations	$ 302,611	$ 186,281
Liabilities incurred and assumed during period	547	43,701
Revisions in estimated retirement obligations	64,667	69,059
Liabilities settled and sold during period	(34,260)	(10,783)
Accretion expense	18,477	14,353
Ending asset retirement obligations	352,042	302,611
Less: current asset retirement obligations(1)	(36,100)	(18,373)
Long-term asset retirement obligations	$ 315,942	$ 284,238

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

Liabilities assumed relate to our March 2021 acquisition of Wyoming property interests (see Note 3, *Acquisition and Divestitures*), and liabilities incurred generally relate to wells and facilities. Revisions during 2022 are primarily due to increased cost estimates associated with both environmental remediation of the surface areas surrounding our well sites as well as increased subsurface abandonment costs due to rising costs. Revisions during 2021 primarily related to increased well abandonment cost estimates at certain of these fields and an acceleration in the estimated timing of certain future abandonment activities.

We have escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $55.9 million and $55.6 million as of December 31, 2022 and 2021, respectively. These balances are primarily invested in U.S. Treasury bonds, recorded at amortized cost, and money market accounts, which investments are included in "Restricted cash for future Asset Retirement obligations" 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, 2022 and 2021.

Note 7. Unevaluated Property

A summary of the unevaluated property costs excluded from oil and natural gas properties being amortized at December 31, 2022, and the year in which the costs were incurred follows:

	December 31, 2022				
	Costs Incurred During:				
In thousands	2022	2021	Successor 2020	Fresh Start Adjustments (Sept. 18, 2020)[1]	Total
Property acquisition costs	$ —	$ —	$ —	$ 64,077	$ 64,077
Exploration and development	132,494	35,881	—	—	168,375
Capitalized interest	3,824	3,575	584	—	7,983
Total	$ 136,318	$ 39,456	$ 584	$ 64,077	$ 240,435

(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, 2022.

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 and Salt Creek fields. Exploration and development costs shown as unevaluated properties are primarily associated with our tertiary oil field projects at Cedar Creek Anticline that are under development but did not have associated proved reserves at December 31, 2022.

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 ultimate parent company in our corporate structure, Denbury Inc., is the sole issuer of all our outstanding obligations under our 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.

Senior Secured Bank Credit Facility

On September 18, 2020, we entered into a $575 million credit agreement for a senior secured revolving credit facility with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (as amended, the "Bank Credit Agreement"). Under the 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 Bank Credit Agreement. 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. The borrowing base is adjusted at the lenders' discretion and is based, in part, upon external factors over which we have no control. If our outstanding debt under the 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 undrawn portion of the aggregate lender commitments under the Bank Credit Agreement is subject to a commitment fee of 0.5% per annum. Our outstanding borrowings under the Bank Credit Agreement, totaled $29.0 million and $35.0 million as of December 31, 2022 and December 31, 2021, respectively, and as of December 31, 2022, we had $10.1 million of outstanding letters of credit.

On May 4, 2022, we entered into a Second Amendment to the Bank Credit Agreement, which among other things:

- Increased the borrowing base and lender commitments from $575 million to $750 million;
- Extended the maturity date from January 30, 2024 to May 4, 2027;
- Modified the interest provisions on loans under the Bank Credit Agreement to (1) reduce the applicable margin for alternate base rate loans from 2% to 3% per annum to 1.5% to 2.5% per annum and (2) replace provisions referencing LIBOR loans with Secured Overnight Financing Rate "(SOFR)" loans, with an applicable margin of 2.5% to 3.5% per annum; and
- Permitted us to pay dividends on and repurchase our common stock and make other unlimited restricted payments and investments so long as (1) no event of default or borrowing base deficiency exists; (2) our total leverage ratio is 1.5 to 1 or lower; and (3) availability under the Bank Credit Agreement is at least 20% of the borrowing base.

As part of our Fall 2022 semiannual borrowing base redetermination, the borrowing base and lender commitments for our Bank Credit Agreement were reaffirmed at $750 million, with our next scheduled redetermination around May 1, 2023.

On January 20, 2023, we entered into a Third Amendment to the Bank Credit Agreement, which among other things, provides us the ability to make and repay certain SOFR loan borrowings on a weekly basis.

The Bank Credit Agreement 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 certain exceptions to such limitations, as specified in the Bank Credit Agreement. Our Bank Credit Agreement required certain minimum commodity hedge levels in connection with our emergence from bankruptcy; however, these conditions were met as of December 31, 2020, and we currently have no ongoing hedging requirements under the Bank Credit Agreement.

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

- A Consolidated Total Debt to Consolidated EBITDAX covenant (as defined in the Bank Credit Agreement), 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 1.0.

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.

The weighted average interest rate on borrowings outstanding as of December 31, 2022 under the Bank Credit Agreement was 9%. As of December 31, 2022, we were in compliance with all debt covenants under the Bank Credit Agreement.

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

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 $9.2 million and $5.7 million at December 31, 2022 and 2021, respectively. Issuance costs associated with our Bank Credit Agreement are included in "Other assets" in the Consolidated Balance Sheets.

Indebtedness Repayment Schedule

The $29.0 million total indebtedness as of December 31, 2022 is due in 2027.

Note 9. Income Taxes

Our income tax provision (benefit) is as follows:

	Successor			Predecessor
In thousands	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Current income tax expense (benefit)				
Federal	$ 3,055	$ —	$ —	$ (6,407)
State	2,308	403	30	(853)
Total current income tax expense (benefit)	5,363	403	30	(7,260)
Deferred income tax expense (benefit)				
Federal	63,814	—	—	(319,011)
State	5,667	364	(2,556)	(89,858)
Total deferred income tax expense (benefit)	69,481	364	(2,556)	(408,869)
Total income tax expense (benefit)	$ 74,844	$ 767	$ (2,526)	$ (416,129)

At December 31, 2022, we had general business credit carryforwards totaling $10.5 million that begin to expire in 2041. In connection with our restructuring in 2020, net operating loss carryforwards ("NOLs"), and tax credit carryforwards for enhanced oil recovery and research and development generated prior to January 1, 2021 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, 2022, we had $0.6 million of alternative minimum tax credits, which under the Tax Cut and Jobs Act passed in 2017 are fully refundable and are recorded as a receivable on the balance sheet, and state NOLs and tax credits totaling $48.2 million (before provision for valuation allowance) related to our state operations. 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, 2022 and 2021 balance sheet dates. Based on all available evidence, both positive and negative, we reached a determination as of March 31, 2022, that there was sufficient positive evidence, primarily related to a substantial increase in worldwide oil prices and taxable income generated from future reversals of existing taxable temporary differences, to conclude that our federal and certain state deferred tax assets are more likely than not to be realized. Based on this determination, in 2022 we reversed the valuation allowance on our federal and certain state deferred tax assets by $51.4 million and $14.8 million, respectively. The reversal of state valuation allowance relates to certain state deferred tax assets for Mississippi, Montana and North Dakota. As of December 31, 2022, we had $59.2 million of net state deferred tax assets associated with operations in Louisiana, Alabama, as well as certain Mississippi tax credits, 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
In thousands	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Beginning balance	$ 125,462	$ 129,408	$ 129,840	$ 77,215
Charges	790	29,345	2,269	77,138
Deductions	(67,019)	(33,291)	(2,701)	(24,513)
Ending balance	$ 59,233	$ 125,462	$ 129,408	$ 129,840

Significant components of our deferred tax assets and liabilities as of December 31, 2022 and 2021 are as follows:

In thousands	December 31, 2022	December 31, 2021
Deferred tax assets		
Loss and tax credit carryforwards – state	$ 48,172	$ 54,943
Derivative contracts	—	30,892
Accrued liabilities and other reserves	19,155	19,567
Business credit carryforwards	10,487	18,066
Loss carryforwards – federal	—	10,310
Lease liabilities	1,998	4,523
Property and equipment	—	2,613
Other	5,974	4,206
Valuation allowances	(59,233)	(125,462)
Total deferred tax assets	26,553	19,658
Deferred tax liabilities		
Property and equipment	(78,055)	—
CO_2 and other contracts	(15,304)	(17,208)
Operating lease right-of-use assets	(2,770)	(4,088)
Derivative contracts	(1,544)	—
Total deferred tax liabilities	(97,673)	(21,296)
Total net deferred tax liability	$ (71,120)	$ (1,638)

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
In thousands	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Income tax provision calculated using the federal statutory income tax rate	$ 116,551	$ 11,921	$ (11,169)	$ (388,228)
State income taxes	20,642	1,468	8,509	(120,340)
Tax windfall on stock-based compensation deduction	(158)	(267)	—	(1,380)
Nondeductible compensation	2,303	5,057	—	—
Change in valuation allowance	(66,229)	(3,946)	(432)	52,625
EOR and other	(1,530)	(14,272)	—	—
Tax attributes reduction – net of cancellation of indebtedness income exclusion	—	—	—	31,667
Other	3,265	806	566	9,527
Total income tax expense (benefit)	$ 74,844	$ 767	$ (2,526)	$ (416,129)

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 2019 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 September 18, 2020, in connection with the Company's emergence from Chapter 11 proceedings, the Company entered into a registration rights agreement (the "Registration Rights Agreement") with certain former beneficial holders of second lien notes of the Predecessor that entered into the restructuring support agreement leading to the restructuring of the Company pursuant to a prepackaged plan of reorganization and pursuant to which the Company included these holders' shares of common stock of the Successor in an automatically effective resale registration statement filed with the SEC in April 2021 for their use in connection with resale of these shares. Under the Registration Rights Agreement, these security holders have customary demand and piggyback registration rights, subject to the limitations set forth in the Registration Rights Agreement. 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.

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 $5.8 million during 2022, $5.1 million during 2021, $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).

Share Repurchase Program

In early May 2022, our Board of Directors authorized a common share repurchase program for up to $250 million of outstanding Denbury common stock. During June and July 2022, the Company repurchased 1,615,356 shares of Denbury common stock under this program for approximately $100 million, at an average price of $61.92 per share. In August 2022, the Board increased Denbury's stock repurchase authorization by $100 million, thus a total of $250 million of common stock currently remains authorized for future repurchases under this program. The program has no pre-established ending date and may be suspended or discontinued at any time. The Company is not obligated to repurchase any dollar amount or specific number of shares of its common stock under the program.

Retirement of Treasury Stock

During the year ended December 31, 2022, we retired 1.6 million shares of existing treasury stock, with a carrying value of $100.0 million, acquired primarily through our stock repurchase program. Upon the retirement of treasury stock, we reduce common stock by the par value of common stock retired, and we reduce additional paid-in capital by the value of those shares in excess of par value.

Employee Stock Purchase Plan – Successor

On June 1, 2022, the Company's stockholders approved the Denbury Inc. Employee Stock Purchase Plan authorizing the sale of up to 2,000,000 shares of common stock thereunder. In accordance with the ESPP, full-time employees may contribute up to 10% of their base salary, subject to certain limitations, to purchase previously unissued Denbury common stock. Participants in the ESPP may purchase common stock at a 15% discount to the fair market value of a share of common stock determined as the lower of the closing sales price on the first or last trading day of each offering period. The first offering period under the ESPP commenced on September 1, 2022 and ended on December 31, 2022 for which the Company issued 7,604 shares. The plan is administered by the Compensation Committee of our Board of Directors.

Note 11. Stock Compensation

Below is a description of stock compensation relating to both the Predecessor period (January 1, 2020 through September 18, 2020), and the Successor periods (September 19, 2020 through December 31, 2020, and each of the years ending December 31, 2021 and 2022). 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, 2022. 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:

In thousands	Successor			Predecessor
	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Stock-based compensation expense included in G&A	$ 16,055	$ 25,322	$ 8,212	$ 4,111
Stock-based compensation capitalized	1,012	1,883	695	1,660
Total cost of stock-based compensation arrangements	$ 17,067	$ 27,205	$ 8,907	$ 5,771
Income tax benefit recognized for stock-based compensation arrangements	$ 1,663	$ 1,846	$ 2,053	$ 1,028

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, 2022, 3.6 million shares were available for future grants under the LTIP, all of which could be issued in the form of restricted stock, 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 and Awards – Successor

Non-performance-based restricted stock unit ("RSU") awards were granted to a limited number of employees and Directors in December of 2020 and to Directors in March 2022 under the Successor's LTIP. Additionally, in March 2022, we granted non-performance-based restricted stock awards to 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 ratably over a three-year period with delivery of the shares occurring at the end of the three-year period. Vested non-performance-based RSU awards provide the holders with dividend equivalent rights payable upon settlement of the underlying RSU awards. 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.

Holders of non-performance-based restricted stock awards have the rights of owning non-restricted stock (including voting rights) except that the holders are not entitled to delivery of a portion thereof until certain requirements are met. Non-performance-based restricted stock awards vest ratably over a three-year period, with the specific terms of vesting determined at the time of grant and delivery of the shares occurring upon vesting. Non-performance-based restricted stock awards provide the holders with forfeitable dividend equivalent rights which vests with the underlying shares. The grant-date fair value of the restricted stock awards is based on the fair market value of our common stock on the date of grant.

As of December 31, 2022, there was $9.3 million and $8.7 million of unrecognized compensation expense related to the Successor's non-performance-based restricted stock unit grants and restricted stock awards, respectively. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 0.9 years and 1.6 years, respectively. The following is a summary of the total vesting date fair value of non-performance-based restricted stock and the weighted average grant-date fair value of restricted stock granted of units and awards:

In thousands, except weighted-average grant-date fair value	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020
Fair value of restricted stock units vested	$ 36,047	$ 31,073	$ —
Weighted-average grant-date fair value of restricted stock units granted during year	76.08	31.87	24.67
Fair value of restricted stock awards vested	$ 6	$ —	$ —
Weighted-average grant-date fair value of restricted stock awards granted during year	76.87	—	—

A summary of the status of our non-performance-based RSUs and restricted stock awards issued and the changes during the year ended December 31, 2022 (Successor) period is presented below:

Restricted Stock Units	Number of Awards	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2021	849,907	$ 25.08
Granted	15,893	76.08
Vested	(412,065)	25.05
Forfeited	(23,842)	24.67
Nonvested at December 31, 2022	429,893	27.02

Restricted Stock Awards	Number of Awards	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2021	—	$ —
Granted	158,692	76.87
Vested	(98)	76.08
Forfeited	(5,737)	76.08
Nonvested at December 31, 2022	152,857	76.90

Performance-Based Stock Units – Successor

In December 2020 and March 2022, the Successor Board of Directors granted performance stock unit ("PSU") awards to a limited number of employees. The PSU awards granted in December 2020 had vesting parameters tied to the Company's common stock trading prices and became fully vested on March 3, 2021. Although the performance measures for vesting of these awards have been achieved, delivery of the shares will not occur until the conclusion of the three-year performance period, December 4, 2023. The PSU awards granted in March 2022 vest over approximately 3 years and the number of performance-based awards earned (and eligible to vest) during the performance period will depend upon the performance of our stock relative to that of a designated peer group. Generally, one-half of the maximum number of shares that could be earned under the performance-based awards will be earned for performance at the designated target levels (100% target vesting levels) or upon any earlier change of control, and twice the target number of shares will be earned if the maximum target levels are met (200% of target vesting levels). The shares earned will be issued upon vesting of the award on March 1, 2025. Vested performance-based PSU awards provide the holders with dividend equivalent rights payable upon settlement of the underlying PSU awards. Shares to be delivered to participants are expected to be made available from authorized but unissued shares reserved under the LTIP.

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, 2022, there was $6.9 million of remaining unrecognized compensation expense related to the Successor's PSU awards. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 2.2 years. The range of assumptions used in the Monte Carlo simulation valuation approach is as follows:

	Successor	
	Year Ended Dec. 31, 2022	Period from Sept. 19, 2020 through Dec. 31, 2020
Weighted average fair value of PSU awards granted	$ 89.43	$ 24.19
Weighted average risk-free interest rate	1.76 %	0.21 %
Expected life	2.96 years	0.23 years
Weighted average expected volatility	61.6 %	110.0 %
Dividend yield	— %	— %

A summary of the PSU awards activity during the year ended December 31, 2022 (Successor) is as follows:

	Number of Awards	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2021	—	$ —
Granted	110,385	89.43
Vested	—	—
Forfeited	(4,273)	90.86
Nonvested at December 31, 2022	106,112	89.37

The following is a summary of the total vesting date fair value and weighted average grant-date fair value of PSU awards:

In thousands, except weighted average grant date fair value	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020
Fair value of performance stock units vested	$ —	45,077	—
Weighted-average grant-date fair value of performance stock units granted during year	89.43	—	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 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.

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:

In thousands	Period from Jan. 1, 2020 through Sept. 18, 2020
Fair value of restricted stock vested	$ 707

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 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 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").

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:

	Period from Jan. 1, 2020 through Sept. 18, 2020
Weighted average fair value of Performance-Based TSR Awards granted	$ 0.15
Risk-free interest rate	0.27 %
Expected life	3.0 years
Expected volatility	89.6 %
Dividend yield	— %

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

In thousands	Period from Jan. 1, 2020 through Sept. 18, 2020
Fair value of Performance-Based TSR awards vested	79

In June 2020, all outstanding performance-based equity awards were cancelled and replaced with a cash retention incentive (see *June 2020 Compensation Adjustments – Predecessor*); there was no remaining compensation cost as of September 18, 2020 to be recognized in future periods related to performance-based equity awards.

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, expectation of future commodity prices, and occasionally requirements under our bank credit facility.

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 Bank Credit Agreement (or affiliates of such lenders). As of December 31, 2022, 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, 2022, none of which are classified as hedging instruments in accordance with the FASC *Derivatives and Hedging* topic:

Months	Index Price	Volume (Barrels per day)	Contract Prices ($/Bbl) Weighted Average Price Swap	Floor	Ceiling
Oil Contracts:					
2023 Fixed-Price Swaps					
Jan – Jun	NYMEX	9,500	$ 76.65	$ —	$ —
July – Dec	NYMEX	11,000	78.48	—	—
2023 Collars					
Jan – Jun	NYMEX	17,500	$ —	$ 69.71	$ 100.42
July – Dec	NYMEX	9,000	—	68.33	100.69

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. Our costless 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.

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, 2022 and 2021:

	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, 2022				
Assets				
Oil derivative contracts – current	$ —	$ 15,517	$ —	$ 15,517
Oil derivative contracts – long-term	—	—	—	—
Total Assets	$ —	$ 15,517	$ —	$ 15,517
Liabilities				
Oil derivative contracts – current	$ —	$ (13,018)	$ —	$ (13,018)
Oil derivative contracts – long-term	—	—	—	—
Total Liabilities	$ —	$ (13,018)	$ —	$ (13,018)
December 31, 2021				
Liabilities				
Oil derivative contracts – current	$ —	$ (134,509)	$ —	$ (134,509)
Oil derivative contracts – long-term	—	—	—	—
Total Liabilities	$ —	$ (134,509)	$ —	$ (134,509)

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.

Other Fair Value Measurements

The carrying value of our loans under our 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. The estimated fair value of the principal amount of our debt as of December 31, 2022 and 2021 was $29.0 million and $35.0 million, respectively. 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 cancellable only upon the occurrence of specified future events. The commitments continue for up to 6 years. The price we will pay for CO_2 generally varies depending on the amount of CO_2 delivered and the price of oil. In addition, we have a processing fee contract related to our overriding royalty interest in the CO_2 at LaBarge Field. Our annual commitment under these contracts could range from $40.6 million to $52.0 million in 2023, assuming a $75 per Bbl NYMEX oil price and declines in future years as the CO_2 purchase contract commitments expire.

During the first quarter of 2022, we entered into a CO_2 storage agreement that included two non-cancellable payments of $2 million, totaling $4 million, due in 2023 and 2024.

We are party to long-term contracts that require us to deliver CO_2 to our customers who are industrial end-users of CO_2 or EOR customers at various contracted prices. Based upon the maximum daily contract quantities as stated in the industrial contracts, total amounts deliverable to these customers could be up to 478 Bcf of CO_2 over the next 12 years.

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.

On May 26, 2022, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the U.S. Department of Transportation issued a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order ("NOPV") relating to the February 2020 pipeline failure near Satartia, Mississippi in our CO_2 pipeline running between the Tinsley and Delhi fields. The NOPV proposed a preliminarily assessed civil penalty of $3.9 million in connection with the incident, which we recorded in our second quarter of 2022 financial statements. We have responded to the NOPV and are pursuing discussions with PHMSA regarding the probable violations alleged in the NOPV, the proposed civil penalty, and the nature of the compliance order contained in the NOPV.

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

Trade and Other Receivables, Net

In thousands	December 31, 2022	December 31, 2021
Trade accounts receivable, net	$ 19,619	$ 10,832
Federal income tax receivable, net	597	597
Other receivables	7,127	7,841
Total	$ 27,343	$ 19,270

Rollforward of Allowance for Doubtful Accounts

	Successor			Predecessor
In thousands	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Beginning balance	$ 18,947	$ 23,206	$ 22,146	$ 17,137
Provision for doubtful accounts	1,270	826	1,060	5,297
Write-offs	—	(5,085)	—	(288)
Ending balance	$ 20,217	$ 18,947	$ 23,206	$ 22,146

Accounts Payable and Accrued Liabilities

In thousands	December 31, 2022	December 31, 2021
Accounts payable	$ 58,905	$ 25,700
Accrued asset retirement obligations – current	36,100	18,373
Accrued lease operating expenses	29,454	27,901
Accrued exploration and development costs	28,963	18,936
Accrued compensation	27,025	23,735
Taxes payable	19,487	14,453
Accrued derivative settlements	9,452	27,336
Other	39,414	35,164
Total	$ 248,800	$ 191,598

Note 16. Supplemental Cash Flow Information

Supplemental Cash Flow Information

	Successor			Predecessor
In thousands	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Supplemental cash flow information				
Cash paid for interest, expensed	$ 1,961	$ 4,227	$ 813	$ 29,357
Cash paid for interest, capitalized	4,237	4,585	1,261	22,885
Cash paid for interest, treated as a reduction of debt	—	—	—	46,417
Cash paid for income taxes	7,543	184	—	453
Cash received from income tax refunds	3	3	10,457	1,932
Noncash investing and financing activities				
Increase in asset retirement obligations	65,214	112,760	23,398	4,328
Increase (decrease) in liabilities for capital expenditures	27,271	35,679	1,867	(12,809)
Conversion of convertible senior notes into common stock	—	—	—	11,501

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 $3.8 million for the year ended December 31, 2022, $4.3 million for year ended December 31, 2021, $1.2 million for the period September 19, 2020 through December 31, 2020, and $22.0 million for the period January 1, 2020 through September 18, 2020. Costs incurred include asset retirement obligations incurred and acquired. Asset retirement obligations included in the table below were $0.4 million for the year ended December 31, 2022, $43.7 million for the year ended December 31, 2021, $3.4 million for the period September 19, 2020 through December 31, 2020, and $2.5 million for the period January 1, 2020 through September 18, 2020. See Note 6, *Asset Retirement Obligations*, for additional information.

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

	Successor			Predecessor
In thousands	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Property acquisitions				
Proved[1]	$ 1,115	$ 50,935	$ 130	$ 278
Unevaluated	—	—	—	—
Exploration	4,402	79	60	260
Development	353,446	172,214	23,741	92,212
Total costs incurred[2]	$ 358,963	$ 223,228	$ 23,931	$ 92,750

(1) Proved property acquisitions in 2021 include $39.8 million of asset retirement obligations associated with our acquisition of interests in the Big Sand Draw and Beaver Creek fields. See Note 3, *Acquisitions and Divestitures,* for additional information.

(2) Capitalized general and administrative costs that directly relate to exploration and development activities were $25.3 million for the year ended December 31, 2022, $24.9 million for the year ended December 31, 2021, $5.6 million for the period September 19, 2020 through December 31, 2020, and $19.5 million for the period January 1, 2020 through September 18, 2020.

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
In thousands, except per-BOE data	Year Ended Dec. 31, 2022	Year Ended Dec. 31, 2021	Period from Sept. 19, 2020 through Dec. 31, 2020	Period from Jan. 1, 2020 through Sept. 18, 2020
Oil, natural gas, and related product sales	$ 1,578,682	$ 1,159,955	$ 201,108	$ 492,101
Lease operating expenses	502,409	424,550	101,234	250,271
Transportation and marketing expenses	20,112	28,817	10,595	27,164
Production and ad valorem taxes	128,302	88,468	15,061	38,647
Depletion, depreciation, and amortization	121,918	119,997	37,549	104,504
CO_2 properties and pipelines depletion and depreciation[1]	6,796	7,180	1,744	33,839
Write-down of oil and natural gas properties	—	14,377	1,006	996,658
Commodity derivatives expense (income)	178,744	352,984	61,902	(102,032)
Net operating income (loss)	620,401	123,582	(27,983)	(856,950)
Income tax provision (benefit)	83,754	—	—	(214,238)
Results of operations from oil and natural gas producing activities	$ 536,647	$ 123,582	$ (27,983)	$ (642,712)
Depletion, depreciation, and amortization per BOE	$ 7.53	$ 7.14	$ 7.72	$ 10.15

(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, 2022.

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 reserves 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 2022, 2021 and 2020 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the applicable fiscal 12-month period. All of our reserves are located in the United States.

Estimated Quantities of Proved Reserves

	Year Ended December 31,								
	2022			2021			2020		
	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)
Balance at beginning of year	188,938	16,506	191,689	140,499	15,604	143,100	226,133	24,334	230,189
Revisions of previous estimates	24,863	16,378	27,593	55,998	(615)	55,895	(63,359)	(5,822)	(64,329)
Production	(16,535)	(3,299)	(17,085)	(17,258)	(3,261)	(17,801)	(18,237)	(2,905)	(18,721)
Acquisition of minerals in place	—	—	—	9,765	5,764	10,725	—	—	—
Sales of minerals in place	—	—	—	(66)	(986)	(230)	(4,038)	(3)	(4,039)
Balance at end of year	197,266	29,585	202,197	188,938	16,506	191,689	140,499	15,604	143,100
Proved Developed Reserves – end of year	193,343	29,585	198,274	179,147	16,506	181,898	136,402	15,604	139,003
Proved Undeveloped Reserves – end of year	3,923	—	3,923	9,791	—	9,791	4,097	—	4,097

Revisions of previous estimates reflect changes in commodity prices resulting in upward revisions of 23.1 MMBOE and 50.1 MMBOE during 2022 and 2021, respectively and downward revisions of 75.7 MMBOE during 2020.

There were no significant additions, excluding acquisitions of minerals in place in 2021, 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 2021 or 2020. During 2022, we initiated a new tertiary flood at CCA but have not yet recognized proved reserves associated with this project. Acquisition of minerals in place during 2021 were related to our Wind River Basin acquisition.

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 reserves 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 (as shown in the table below) 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. These prices were further adjusted by field to arrive at the appropriate corporate net price.

	December 31,		
	2022	2021	2020
Oil (NYMEX price per Bbl)	$ 93.67	$ 66.56	$ 39.57
Natural Gas (Henry Hub price per MMBtu)	6.36	3.60	1.99

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 2020 and 2022. The weighted average oil prices we receive relative to NYMEX oil prices (our NYMEX oil price differential) utilized were $0.65 per Bbl below representative NYMEX oil prices as of December 31, 2022, compared to $2.70 per Bbl below representative NYMEX oil prices as of December 31, 2021, and $3.73 per Bbl below representative NYMEX oil prices as of December 31, 2020.

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	2022	2021	2020
Future cash inflows	$ 18,385,963	$ 12,020,943	$ 5,010,288
Future production costs	(9,450,935)	(6,652,315)	(3,300,890)
Future development costs	(1,233,166)	(1,116,998)	(962,224)
Future income taxes	(1,644,542)	(776,337)	(59,600)
Future net cash flows	6,057,320	3,475,293	687,574
10% annual discount for estimated timing of cash flows	(2,566,397)	(1,288,242)	(32,840)
Standardized measure of discounted future net cash flows	$ 3,490,923	$ 2,187,051	$ 654,734

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	2022	2021	2020
Beginning of year	$ 2,187,051	$ 654,734	$ 2,261,039
Sales of oil and natural gas produced, net of production costs	(927,858)	(618,119)	(250,237)
Net changes in prices and production costs	2,417,990	2,360,251	(1,753,248)
Previously estimated development costs incurred	68,515	36,074	28,182
Change in future development costs	(13,755)	(15,623)	11,200
Revisions due to timing and other	(4,418)	35,887	(127,046)
Accretion of discount	242,760	68,119	233,663
Acquisition of minerals in place	—	105,610	—
Sales of minerals in place	—	(1,454)	(55,102)
Net change in income taxes	(479,362)	(438,428)	306,283
End of year	$ 3,490,923	$ 2,187,051	$ 654,734

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	2022	2021	2020
CO_2 reserves			
Gulf Coast region[1]	3,808,436	4,474,313	4,641,812
Rocky Mountain region[2]	996,330	1,046,139	1,089,101

(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 3.0 Tcf, 3.6 Tcf and 3.7 Tcf at December 31, 2022, 2021 and 2020, respectively.

(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 1.0 Tcf, 1.0 Tcf and 1.1 Tcf at December 31, 2022, 2021 and 2020, 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, 2022, 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 2022, 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, 2022, 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.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

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 2023 Annual Meeting of Shareholders to be held June 1, 2023 ("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

Our independent registered public accounting firm is PricewaterhouseCoopers LLP, Dallas, TX, PCAOB Auditor ID: 238.

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 65. 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).
4(d)*	Description of Denbury Inc. equity securities registered under Section 12 of the Securities Exchange Act of 1934, as amended.
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)	First Amendment to Credit Agreement, dated as of November 3, 2021, by and among Denbury Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on November 4, 2021, File No. 001-12935).
10(c)	Second Amendment to Credit Agreement, dated as of May 4, 2022, by and among Denbury Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto. (incorporated by reference to Exhibit 10(d) of Form 10-Q filed by the Company on May 6, 2022, File No. 001-12935).
10(d)*	Third Amendment to Credit Agreement, dated as of January 20, 2023, by and among Denbury Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto.

Exhibit No.	Exhibit
10(e)**	Denbury Inc. Employee Stock Purchase Plan (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on June 6, 2022, File No. 001-12935).
10(f)**	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(g)	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(h)**	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(i)**	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(j)**	2020 Form of Restricted Stock Unit Award under the 2020 Omnibus Stock and Incentive Plan for Denbury Inc. (incorporated by reference to Exhibit 10(f) of Form 10-K filed by the Company on March 5, 2021, File No. 001-12935).
10(k)**	2020 Form of Director Deferred Stock Unit Award under the 2020 Omnibus Stock and Incentive Plan for Denbury Inc. (incorporated by reference to Exhibit 10(g) of Form 10-K filed by the Company on March 5, 2021, File No. 001-12935).
10(l)**	2020 Form of Performance Stock Unit Award under the 2020 Omnibus Stock and Incentive Plan for Denbury Inc. (incorporated by reference to Exhibit 10(h) of Form 10-K filed by the Company on March 5, 2021, File No. 001-12935).
10(m)**	2022 Form of Restricted Stock Award under the 2020 Omnibus Stock and Incentive Plan for Denbury Inc. (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on May 6, 2022, File No. 001-12935).
10(n)**	2022 Form of Deferred Stock Unit Award under the 2020 Omnibus Stock and Incentive Plan for Denbury Inc. (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on May 6, 2022, File No. 001-12935).
10(o)**	2022 Form of TSR Performance Award under the 2020 Omnibus Stock and Incentive Plan for Denbury Inc. (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on May 6, 2022, File No. 001-12935).
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.

Exhibit No.	Exhibit
99*	The summary of DeGolyer and MacNaughton's Report as of December 31, 2022, on oil and gas reserves dated February 1, 2023.
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.
February 23, 2023	/s/ Mark C. Allen
	Mark C. Allen Executive Vice President and Chief Financial Officer
February 23, 2023	/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.

Denbury Inc.

February 23, 2023	/s/ Christian S. Kendall Christian S. Kendall Director, President and Chief Executive Officer (Principal Executive Officer)
February 23, 2023	/s/ Mark C. Allen Mark C. Allen Executive Vice President and Chief Financial Officer (Principal Financial Officer)
February 23, 2023	/s/ Nicole Jennings Nicole Jennings Vice President and Chief Accounting Officer (Principal Accounting Officer)
February 23, 2023	/s/ Kevin O. Meyers Kevin O. Meyers Director
February 23, 2023	/s/ Anthony Abate Anthony Abate Director
February 23, 2023	/s/ Caroline Angoorly Caroline Angoorly Director
February 23, 2023	/s/ James Chapman James Chapman Director
February 23, 2023	/s/ Lynn A. Peterson Lynn A. Peterson Director
February 23, 2023	/s/ Brett Wiggs Brett Wiggs Director
February 23, 2023	/s/ Cindy A. Yeilding Cindy A. Yeilding 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 Statements on Form S-8 (Nos. 333-251121 and 333-266528) and Form S-3 (No. 333-255218) of Denbury Inc. of our report dated February 23, 2023 relating to the financial statements and the effectiveness of internal control over financial reporting of Denbury Inc. (Successor), which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Dallas, Texas
February 23, 2023

Exhibit 23(b)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (No. 333-251121) and Form S-3 (No. 333-255218) of Denbury Inc. of our report dated March 5, 2021 relating to the financial statements of Denbury Resources Inc. (Predecessor), which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Dallas, Texas
February 23, 2023

Exhibit 23(c)

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

February 23, 2023

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 1, 2023, regarding the proved reserves of Denbury Inc., and to the inclusion of information taken from our reports entitled “Report as of December 31, 2022 on Reserves and Revenue of Certain Properties with interests attributable to Denbury Inc.,” “Report as of December 31, 2021 on Reserves and Revenue of Certain Properties with interests attributable to Denbury Inc.,” and “Report as of December 31, 2020 on Reserves and Revenue of Certain Properties with interests attributable to Denbury Resources Inc.” in the Annual Report on Form 10-K of Denbury Inc. for the year ended December 31, 2022.

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.

February 23, 2023

/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.

February 23, 2023

/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, 2022 (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: February 23, 2023

/s/ Christian S. Kendall

Christian S. Kendall

Director, President and Chief Executive Officer

Dated: February 23, 2023

/s/ Mark C. Allen

Mark C. Allen

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

Corporate Information

BOARD OF DIRECTORS

Kevin Meyers
Chairman of the Board
Independent Consultant

Anthony Abate
Independent Consultant

Caroline Angoorly
Managing Partner
GreenTao LLC

James Chapman
Independent Consultant

Chris Kendall
President and Chief Executive Officer
Denbury Inc.

Lynn Peterson
Executive Chairman
Chord Energy

Brett Wiggs
Chief Executive Officer
Oryx Midstream Services

Cindy 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

CORPORATE HEADQUARTERS

Denbury Inc.
5851 Legacy Circle, Suite 1200
Plano, Texas 75024
972.673.2000
www.denbury.com

EXECUTIVE OFFICERS

Chris 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

David Sheppard
Executive Vice President,
Chief Operating Officer

Jenny Cochran
Senior Vice President, Business Services

Matt Dahan
Senior Vice President, Business Development and Technology

Nik Wood
Senior Vice President, CCUS

STOCK EXCHANGE LISTING

New York Stock Exchange (“NYSE”)
Ticker Symbol: DEN

STOCK TRANSFER AGENT AND REGISTRAR

For questions concerning 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

FINANCIAL INFORMATION REQUESTS

For information and to receive 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 our 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 willbe held virtually at:

www.virtualshareholdermeeting.com/DEN2023 at 8:00 A.M. CDT on Thursday, June 1, 2023.

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

PricewaterhouseCoopers LLP

RESERVES ENGINEERS

DeGolyer and MacNaughton

Denbury

Denbury Inc.

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