ANNUAL REPORT 2022

A DIFFERENT KIND OF ENERGY COMPANY

CALIFORNIA RESOURCES CORPORATION

CARBON TERRAVAULT

FINANCIAL & OPERATIONAL HIGHLIGHTS

FINANCIAL HIGHLIGHTS		2022		2021		2020 Combined*
Dollar amounts in millions, except share and per-share amounts, as of and for the years ended December 31,						
Total Operating Revenue	$	2,707	$	1,889	$	1,559
Net Income	$	524	$	625	$	1,871
Net Income Attributable to Noncontrolling Interests	$	0	$	13	$	105
Net Income (Loss) Attributable to Common Stock	$	524	$	612	$	1,766
Adjusted Net Income (Loss) Attributable to Common Stock[(a)]	$	384	$	506	$	(257)
Net Income (Loss) Attributable to Common Stock per Share – Diluted	$	6.75	$	7.37		–
Adjusted Net Income (Loss) Attributable to Comman Stock[(a)] per Share – Diluted	$	4.95	$	6.10		–
Net Cash Provided by Operating Activities	$	690	$	660	$	106
Capital Investments	$	379	$	194	$	47
Free Cash Flow[(a)]	$	311	$	466	$	59
Net Cash Used in Financing Activities	$	(371)	$	(222)	$	(58)
Total Assets	$	3,967	$	3,846	$	3,074
Long-Term Debt, Net	$	592	$	589	$	597
Equity	$	1,864	$	1,688	$	1,182
Weighted-Average Shares Outstanding - Diluted		77.6		83.0		–
Year-End Shares		71.9		79.3		83.3

OPERATIONAL HIGHLIGHTS		2022		2021		2020 Combined*
Production:						
Oil (MBbl/d)		55		60		69
NGLs (MBbl/d)		11		13		13
Natural Gas (MMcf/d)		147		159		172
Total (MBoe/d)[(b)]		91		100		111
Average Realized Prices:						
Oil with hedge ($/Bbl)	$	61.80	$	56.05	$	43.53
Oil without hedge ($/Bbl)	$	98.26	$	70.43	$	41.89
NGLs ($/Bbl)	$	64.33	$	53.62	$	27.63
Natural Gas ($/Mcf)	$	7.68	$	4.22	$	2.28
Reserves:						
Oil (MMBbl)		294		343		313
NGLs (MMBbl)		38		41		41
Natural Gas (Bcf)		511		576		527
Total (MMBoe)[(b)]		417		480		442
Standardized Measure of Discounted Future Net Cash Flows (in billions)	$	6.7	$	4.5	$	1.9
PV-10 of Cash Flows (in billions)[(a)]	$	9.2	$	6.2	$	2.4
Net Mineral Acreage (in thousands):						
Developed		689		699		717
Undeveloped		1,178		1,192		1,388
Total		1,867		1,891		2,105
Closing Share Price	$	43.51	$	42.71	$	23.59

*Note: 2020 represents the combined successor and predecessor periods as defined in Note 1 - Nature of Business, Summary of Significant Accounting Policies and Other.

(a) Please see crc.com, Investor Relations for copies of CRC's earnings releases and Annual Reports filed on Form 10-K that include a discussion of these performance and non-GAAP measures, including a reconcililation to the most closely related GAAP measure or information on the related calculations.

(b) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas and one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

This report contains forward-looking statements that involve risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects. For a discussion of these risks and uncertainties, please refer to the "Risk Factors" and "Forward-Looking Statements" described in our Annual Report on Form 10-K. Words such as "anticipate," "believe," "continue," "could," "estimate," "expect," "goal," "intend," "likely," "may," "might," "plan," "potential," "project," "seek," "should," "target," "will" or "would" and similar words that reflect the prospective nature of events or outcomes typically identify forward-looking statements. Any forward-looking statement speaks only as of the date on which such statement is made and we undertake no obligation to correct or update any forward-looking statement, except as required by applicable law.

A MESSAGE TO OUR SHAREHOLDERS

Dear Shareholders,

During 2022 we demonstrated the adaptability of our teams, resilience of our assets and optionality of our portfolio. Despite inflationary pressures and an evolving regulatory environment, we remained focused on developing our core low-decline assets in the San Joaquin and Los Angeles basins to deliver some of the lowest carbon intensity barrels in the United States. We generated 91,000 barrels of oil equivalent per day and delivered record operating cash flow and operating margin.

We generated $690 million of operating cash flow, $311 million of free cash flow and returned over 100% of that free cash flow to shareholders through dividends and share repurchases. Since the inception of our share repurchase program in 2021 through year-end 2022, CRC has acquired nearly 14% of our common stock, demonstrating our commitment to shareholder returns.

We also continued to advance our carbon management business. Building off momentum created in 2021, we filed two additional Class VI permits and now have storage applications representing a cumulative total of approximately 140 million metric tons of carbon storage. We also created a joint venture (JV) with Brookfield Renewable targeting sequestration of 5 million metric tons of carbon dioxide. The unique structure of the JV, in which Brookfield may contribute $10 per ton for its 49% share of storage assets under development, provides a marker for the value of our storage reservoirs and is expected to de-risk capital requirements for CRC. Additionally, at the end of 2022 and beginning of 2023, we announced our first two carbon dioxide management agreements – with Lone Cypress Energy Services, LLC, and Grannus, LLC – a significant milestone for our Carbon TerraVault business signifying both the demand for our storage tanks and a pathway to our first carbon capture and storage (CCS) projects.

In addition to advancing CCS, we updated and expanded our ESG goals that build upon CRC's commitment to sustainability and its 2045 Full-Scope Net Zero Goal for Scope 1, 2 and 3 emissions. The ESG goals tie 30% of executive annual incentive pay to ESG metrics; establish ethnic, racial and gender diversity in leadership goals; and enhance our methane and freshwater reduction goals and community giving goal. Our dedication to energy transition and our ongoing sustainability strategy aligns with California's climate goals under the Paris Climate Accord and further positions CRC as one of the leading energy transition companies in the state.

Looking ahead, CRC will maintain its shareholder return mindset with a focus on delivering strong and sustainable cash flows through disciplined capital allocation. CRC continues to adapt and evolve, and I am excited to have Francisco at the helm going forward. I would like to thank the talented women and men of CRC for their dedication and support as we continue to create a different kind of energy company.

Sincerely,

Mark A. (Mac) McFarland
President and Chief Executive Officer
California Resources Corporation

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

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2022

☐ **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 001-36478

California Resources Corporation

(Exact name of registrant as specified in its charter)

Delaware	**46-5670947**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1 World Trade Center, Suite 1500
Long Beach, California 90831
(Address of principal executive offices) (Zip Code)

(888) 848-4754
(Registrant's telephone number, including area code)

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

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock	CRC	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 Date File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or such shorter period as the registrant was required to submit such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	☑	Accelerated Filer	☐	Non-Accelerated Filer	☐
Smaller Reporting Company	☐	Emerging Growth Company	☐		

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

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

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 ☑

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter. Common Stock aggregate market value held by non-affiliates as of June 30, 2022: $2,901,083,185.

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 ☐

At January 31, 2023, there were 71,491,602 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement to be filed within 120 days after December 31, 2022 with the Securities and Exchange Commission in connection with the registrant's 2023 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

GLOSSARY AND SELECTED ABBREVIATIONS

The following are abbreviations and definitions of certain terms used within this Form 10-K:

- ***ABR*** - Alternate base rate.
- ***ASC*** - Accounting Standards Codification.
- ***ARO*** - Asset retirement obligation.
- ***Bbl*** - Barrel.
- ***Bbl/d*** - Barrels per day.
- ***Bcf*** - Billion cubic feet.
- ***Bcfe*** - Billion cubic feet of natural gas equivalent using the ratio of one barrel of oil, condensate, or NGLs converted to six thousand cubic feet of natural gas.
- ***Boe*** - We convert natural gas volumes to crude oil equivalents using a ratio of six thousand cubic feet (Mcf) to one barrel of crude oil equivalent based on energy content. This is a widely used conversion method in the oil and natural gas industry.
- ***Boe/d*** - Barrel of oil equivalent per day.
- ***Btu*** - British thermal unit.
- ***CalGEM*** - California Geologic Energy Management Division.
- ***CCS*** - Carbon capture and storage.
- ***CDMA*** - Carbon Dioxide Management Agreement.
- ***CO_2*** - Carbon dioxide.
- ***DD&A*** - Depletion, depreciation, and amortization.
- ***EOR*** - Enhanced oil recovery.
- ***EPA*** - United States Environmental Protection Agency.
- ***ESG*** - Environmental, social and governance.
- ***E&P*** - Exploration and production.
- ***Full-Scope Net Zero*** - Achieving permanent storage of captured or removed carbon emissions in a volume equal to all of our scope 1, 2 and 3 emissions by 2045.
- ***GAAP*** - United States Generally Accepted Accounting Principles.
- **G&A** - General and administrative expenses.
- ***GHG*** - Greenhouse gases.
- ***JV*** - Joint venture.
- ***LCFS*** - Low Carbon Fuel Standard.
- ***LIBOR*** - London Interbank Offered Rate.
- ***MBbl*** - One thousand barrels of crude oil, condensate or NGLs.
- **MBbl/d** - One thousand barrels per day.
- ***MBoe/d*** - One thousand barrels of oil equivalent per day.
- **MBw/d** - One thousand barrels of water per day
- ***Mcf*** - One thousand cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six thousand cubic feet of natural gas.
- **MHp** - One thousand horsepower.
- ***MMBbl*** - One million barrels of crude oil, condensate or NGLs.
- ***MMBoe*** - One million barrels of oil equivalent.
- ***MMBtu*** - One million British thermal units.
- ***MMcf/d*** - One million cubic feet of natural gas per day.
- ***MMT*** - Million metric tons.
- ***MMTPA*** - Million metric tons per annum.
- ***MW*** - Megawatts of power.
- ***NGLs*** - Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as purity products such as ethane, propane, isobutane and normal butane, and natural gasoline.
- ***NYMEX*** - The New York Mercantile Exchange.
- ***OCTG*** - Oil country tubular goods.

- ***Oil spill prevention rate*** - Calculated as total Boe less net barrels lost divided by total Boe.
- ***OPEC*** - Organization of the Petroleum Exporting Countries.
- ***OPEC+*** - OPEC together with Russia and certain other producing countries.
- ***PHMSA*** - Pipeline and Hazardous Materials Safety Administration.
- ***Proved developed reserves*** - Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
- ***Proved reserves*** - The estimated quantities of natural gas, NGLs, and oil that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic conditions, operating methods and government regulations.
- ***Proved undeveloped reserves*** - Proved reserves that are expected to be recovered from new wells on undrilled acreage that are reasonably certain of production when drilled or from existing wells where a relatively major expenditure is required for recompletion.
- ***PSCs*** - Production-sharing contracts.
- ***PV-10*** - Non-GAAP financial measure and represents the year-end present value of estimated future cash flows from proved oil and natural gas reserves, less future development and operating costs, discounted at 10% per annum and using SEC Prices. PV-10 facilitates the comparisons to other companies as it is not dependent on the tax-paying status of the entity.
- ***Scope 1 emissions*** - Our direct emissions.
- ***Scope 2 emissions*** - Indirect emissions from energy that we use (*e.g.*, electricity, heat, steam, cooling) that is produced by others.
- ***Scope 3 emissions*** - Indirect emissions from upstream and downstream processing and use of our products.
- ***SDWA*** - Safe Drinking Water Act.
- ***SEC*** - United States Securities and Exchange Commission.
- ***SEC Prices*** - The unweighted arithmetic average of the first day-of-the-month price for each month within the year used to determine estimated volumes and cash flows for our proved reserves.
- ***SOFR*** - Secured overnight financing rate as administered by the Federal Reserve Bank of New York.
- ***Standardized measure*** - The year-end present value of after-tax estimated future cash flows from proved oil and natural gas reserves, less future development and operating costs, discounted at 10% per annum and using SEC Prices. Standardized measure is prescribed by the SEC as an industry standard asset value measure to compare reserves with consistent pricing, costs and discount assumptions.
- ***TRIR*** - Total Recordable Incident Rate calculated as recordable incidents per 200,000 hours for all workers (employees and contractors).
- ***Working interest*** - The right granted to a lessee of a property to explore for and to produce and own oil, natural gas or other minerals in-place. A working interest owner bears the cost of development and operations of the property.
- ***WTI*** - West Texas Intermediate.

PART I

ITEMS 1 & 2 BUSINESS AND PROPERTIES

Business Overview and History

We are an independent oil and natural gas exploration and production company operating properties exclusively within California. We provide affordable and reliable energy in a safe and responsible manner, to support and enhance the quality of life of Californians and the local communities in which we operate. We do this through the development of our broad portfolio of assets while adhering to our commitment to create shareholder value. We also have some of the lowest carbon intensity production in the United States. We are committed to energy transition and decarbonization through our carbon management business that we refer to as Carbon TerraVault. We are in the early stages of developing several carbon capture and storage projects in California. In August 2022, Carbon TerraVault entered into a joint venture with BGTF Sierra Aggregator (Brookfield) to pursue certain of these opportunities (Carbon TerraVault JV). Over time, we intend to conduct our carbon management business on a stand-alone basis. We expect that this will provide greater flexibility to consider strategic options, including the potential separation from our E&P business. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Investment in Unconsolidated Subsidiary and Related Party Transactions* for more information on the Carbon TerraVault JV.

We qualified for and adopted fresh start accounting in connection with our emergence from bankruptcy on October 27, 2020, at which point we became a new entity for financial reporting purposes. We adopted an accounting convenience date of October 31, 2020 for the application of fresh start accounting. As a result of the application of fresh start accounting and the effects of the implementation of our joint plan of reorganization (the Plan), the financial statements after October 31, 2020 may not be comparable to the financial statements prior to that date. Accordingly, “black-line” financial statements are presented to distinguish between Predecessor and Successor companies. References to “Predecessor” refer to the Company for periods ending on or prior to October 31, 2020 and references to “Successor” refer to the Company for periods subsequent to October 31, 2020.

See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 15 Chapter 11 Proceedings* and *Note 16 Fresh Start Accounting* for additional information on the terms of the Plan, our emergence from bankruptcy and application of fresh start accounting.

Except when the context otherwise requires or where otherwise indicated, all references to ‘‘CRC,’’ the ‘‘Company,’’ ‘‘we,’’ ‘‘us’’ and ‘‘our’’ refer to California Resources Corporation and its consolidated subsidiaries.

Business Strategy

Our strategy is to continue to develop our oil and natural gas assets while pursuing opportunities in the emerging industries of decarbonization and energy transition. To accomplish our strategy, we have developed the following key priorities:

- **Adjust our corporate structure**. We intend to manage our carbon management business on a stand-alone basis over time. We expect that this will provide greater flexibility to consider strategic options, including the potential separation from our E&P business. We also recently installed a board of directors at Carbon TerraVault Holdings, LLC that will focus on growing and developing our carbon management business on a stand-alone basis.

- **Advance our carbon management business**. We intend to continue to build our carbon management business through Carbon TerraVault. Our efforts will build on the progress made in 2022, including the formation of the Carbon TerraVault JV with Brookfield. We also executed two carbon management service agreements with Lone Cypress Energy Services, LLC and Grannus, LLC to provide permanent carbon storage. We are focused on signing up additional emitter projects and submitting additional Class VI permit applications with the EPA for permanent carbon capture and sequestration. We are also evaluating our Elk Hills power plant as a potential emissions source for carbon capture and sequestration, and are working with a consortium of industry participants to advance the development of a direct air capture hub to be located in Kern County.

- **Execute on a core E&P development plan**. In light of recent regulatory changes in California, we will reduce our average rig count to 1.5 rigs in 2023 (down from approximately 4 rigs in 2022) with a drilling program focused on executing projects where we have permits in hand. We also intend to increase our workover activity in 2023 to help minimize production decline. We further plan to develop field level EIRs for the CEQA review process which we expect will reduce uncertainty in obtaining permits for the majority of our proved undeveloped resources in future years.

- **Focus on cost reductions and portfolio optimization**. In light of the changing regulatory environment in California, we will adjust our capital program in 2023 to optimize near term cash flow. We intend to focus on cost reduction initiatives and expect to reduce our non-energy operating costs and general and administrative costs by the end of the year. We also plan to continue to pursue the sale of our Huntington Beach surface acreage as well as other non-core real estate assets.

- **Improve our financial flexibility and maintain a strong balance sheet.** We are pursuing options to amend and extend or replace our Revolving Credit Facility, as well as refinancing options for our $600 million of Senior Notes. We expect that these steps will allow us to extend our debt maturities and provide us with greater financial flexibility to increase shareholder returns. We also intend to pursue financing options for our carbon management business that are separate from the rest of our business. We remain committed to maintaining our strong liquidity position.

- **Focus on increasing shareholder returns**. CRC intends to optimize capital allocation and focus on cost reduction opportunities in 2023 to drive cash flow generation. We expect that the combination of these efforts will allow us to continue to increase shareholder returns. To that end, our Board has authorized a 30% increase to its shareholder repurchase program for a total of $1.1 billion, with approximately $640 million remaining on its authorization as of December 31, 2022 after taking into account this increase.

- **Maintain our commitment to safety and sustainability and demonstrate leadership on ESG practices in the E&P space.** We are committed to exceptional environmental and safety performance and achieved a 99.9999% oil spill prevention rate in 2022 and registered a workforce TRIR of 0.62. We have some of the lowest carbon intensity production among oil and natural gas producers in the United States and established a Full-Scope Net Zero goal to permanently store captured or removed carbon emissions equal to our Scope 1, 2 and 3 emissions by 2045, which aligns us with the State of California’s 2045 net zero ambitions and puts us ahead of the net zero goals in the Paris Agreement. We intend to achieve this goal through our existing and future decarbonization projects, including those projects that will be developed by the Carbon TerraVault JV. Our ESG goals focus not only on lowering greenhouse gas emissions, but also decreasing methane emissions, reducing freshwater consumption, expanding leadership diversity, enhancing community engagement. We have increased accountability by linking executive compensation to ESG performance. For 2023, 30% of our management team’s annual incentive related to company performance is tied to safety and ESG related metrics, including the advancement of our carbon management business.

Oil and Natural Gas Operations

As of December 31, 2022, our proved reserves totaled an estimated 417 MMBoe, of which 294 MMBbl were crude oil and condensate reserves, 38 MMBbl were NGL reserves and 511 BcF, or 85 MMBoe, were natural gas reserves.

As of December 31, 2022, we held approximately 1.9 million net mineral acres, the largest non-governmental mineral acreage position in California. Our operated asset base spans 97 distinct fields with approximately 10,000 operated wells. We had average net production of approximately 91 MBoe/d (60% oil) for the year ended December 31, 2022.

The following table highlights key information about our operations as of and for the year ended December 31, 2022:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin(a)	Sacramento Basin	Other	Total Operations
Mineral Acreage						
Net mineral acreage (thousands)	1,248	29	6	466	118	1,867
Average net mineral acreage held in fee (%)	81 %	47 %	— %	41 %	97 %	71 %
Number of producing fields we operate	42	5	—	50	—	97
Average drilling rigs	2	2	—	—	—	4
Net wells drilled and completed	114.3	35.0	—	—	—	149.3
Proved reserves						
Oil (MMBbl)	182	112	—	—	—	294
NGLs (MMBbl)	38	—	—	—	—	38
Natural gas (Bcf)	451	7	—	53	—	511
Total (MMBoe)	295	113	—	9	—	417
Oil percentage of proved reserves	62 %	99 %	— %	— %	— %	71 %
Production						
Total net production (MMBoe)	25	7	—	1	—	33
Average daily net production (MBoe/d)	70	18	—	3	—	91

(a) Reflects one non-operated field in the Ventura basin included in assets held for sale. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Divestitures and Acquisitions* for more information on our Ventura Basin divestiture.

For a discussion of the regulatory issues affecting the development of our oil and natural gas properties, see *Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities.*

San Joaquin Basin

Commercial petroleum development in the San Joaquin basin began in the 1800s. The basin contains multiple stacked formations throughout its areal extent, and we believe that this basin provides appealing opportunities for re-development of existing wells, as well as new discoveries and unconventional play potential. The geology of the San Joaquin basin continues to yield stratigraphic and structural trap discoveries.

We hold substantially all the working, surface and mineral interests in the Elk Hills field, which is our largest producing asset in the San Joaquin Basin and have a large ownership interest in several other oil fields located in the San Joaquin basin including Buena Vista and Coles Levee. We have also been successfully developing steamfloods in our Kern Front operations.

At Elk Hills we operate efficient natural gas processing facilities, including a cryogenic gas plant, with a combined gas processing capacity of over 520 MMcf/d. Additionally, our Elk Hills power plant generates sufficient electricity to operate the field, and sells excess power to the wholesale market and a utility. Our operations at Elk Hills also include an advanced central control facility and remote automation control on over 95% of the producing wells.

We believe our extensive 3D seismic library, which covers over 700,000 acres in the San Joaquin basin, or approximately 50% of our gross mineral acreage in this basin, gives us a competitive advantage in field development.

Los Angeles Basin

This basin is a northwest-trending plain about 50 miles long and 20 miles wide. Most of the significant discoveries in the Los Angeles basin date back to the 1920s. The Los Angeles basin has one of the highest concentrations per acre of crude oil in the world. Large active oil fields in this basin include the Wilmington and Huntington Beach fields, where we have significant operations. Most of our Wilmington production is subject to a set of contracts similar to production-sharing contracts (PSCs) under which we first recover the capital and operating costs we incur on behalf of the state and the city of Long Beach and then receive our share of profits. See *Production, Price and Cost History* below for more information on our PSCs.

We are pursuing the potential divestiture of certain real estate properties, including two properties in Huntington Beach. One of these properties is a one-acre parcel at Fort Apache and the other is an approximately 90 acre surface property at our Huntington Beach field. At the Huntington Beach field, we have begun the plugging and abandonment of approximately 30 existing wells and are working towards the longer-term remediation of the larger property to provide flexibility for real estate sales in the future.

Sacramento Basin

The Sacramento basin is a deep, thick sequence of sedimentary deposits of natural gas within an elongated northwest-trending structural feature covering about 7.7 million acres. Exploration and development in the basin began in 1918. Our significant mineral acreage position in the Sacramento basin gives us the option for future development and rapid production growth in an attractive natural gas price environment.

Ventura Basin

We divested a vast majority of our assets in the Ventura basin other than a de minimis non-operated asset, during the fourth quarter of 2021 and the first quarter of 2022. Our remaining Ventura basin asset is expected to be sold in the first half of 2023.

Other

Other than the basins described above, we also have mineral interests in undeveloped acreage throughout California including in the Salinas basin and the Santa Maria basin.

Mineral Acreage

The following table summarizes our gross and net developed and undeveloped mineral acreage as of December 31, 2022.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Other[(a)]	Total
			(in thousands)			
Developed[(b)]						
Gross[(c)]	460	20	6	259	2	747
Net[(d)]	421	15	6	246	1	689
Undeveloped[(e)]						
Gross[(c)]	1,008	17	—	265	142	1,432
Net[(d)]	827	14	—	220	117	1,178
Total						
Gross[(c)]	1,468	37	6	524	144	2,179
Net[(d)]	1,248	29	6	466	118	1,867

(a) Reflects remaining mineral acreage to be retained in the Ventura Basin and nearby areas. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Divestitures and Acquisitions* for more information on our Ventura Basin divestiture.
(b) Mineral acres spaced or assigned to productive wells.
(c) Total number of mineral acres in which interests are owned.
(d) Net mineral acreage includes acreage reduced to our fractional ownership interest and interests under our PSCs.
(e) Mineral acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether the mineral acreage contains proved reserves.

At December 31, 2022, 71% of our total net mineral interest position was held in fee and the remainder was leased. Of our leased acreage, approximately 63% is held by production and the remainder is subject to lease expiration if initial wells are not drilled within a specified period of time. The primary terms of our leases range from one to twenty years. The terms of these leases are typically extended upon achieving commercial production for so long as such production is maintained. Work programs are designed to ensure that the economic potential of any leased property is evaluated before expiration. In some instances, we may relinquish leased acreage in advance of the contractual expiration date if the evaluation process is complete and there is no longer a commercial reason for leasing that acreage. In cases where we determine we want to take the additional time required to fully evaluate undeveloped acreage, we have generally been successful in obtaining extensions.

If we are not able to establish production or otherwise extend lease terms, approximately 41,000 net mineral acres will expire in 2023, 35,000 net mineral acres will expire in 2024 and 14,000 net mineral acres will expire in 2025. These leases represent 8% of our total net undeveloped acreage and 5% of our total net acreage as of December 31, 2022 and these expirations, should they occur, would not have a material adverse impact on us. Historically, we have not dedicated any significant portion of our capital program to prevent lease expirations and do not expect to do so in the future.

Production, Price and Cost History

The following table sets forth information regarding our production volumes, average realized and benchmark prices and operating costs per Boe for the periods presented. See *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations* for more information on our production activity as well as the impact of commodity price increases and inflation on our operating costs per Boe, among other factors.

	Successor			Predecessor
	Year Ended December 31, 2022	Year Ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
Average daily net production				
Oil (MBbl/d)	55	60	63	70
NGLs (MBbl/d)	11	13	12	13
Natural gas (MMcf/d)	147	159	165	174
Total daily net production (MBoe/d)	91	100	103	112
Total production (MMBoe)	33	36	6	34
Average realized prices				
Oil with hedge ($/Bbl)	$ 61.80	$ 56.05	$ 45.37	$ 43.19
Oil without hedge ($/Bbl)	$ 98.26	$ 70.43	$ 45.65	$ 41.21
NGLs ($/Bbl)	$ 64.33	$ 53.62	$ 38.00	$ 25.70
Natural gas without hedge ($/Mcf)	$ 7.68	$ 4.22	$ 3.21	$ 2.11
Average benchmark prices				
Brent oil ($/Bbl)	$ 98.89	$ 70.79	$ 47.10	$ 42.43
WTI oil ($/Bbl)	$ 94.23	$ 67.91	$ 44.21	$ 38.44
NYMEX gas ($/MMBtu) - Contract Month Average	$ 6.36	$ 3.61	$ 2.86	$ 1.95
NYMEX gas ($/MMBtu) - Average Monthly Settled Price	$ 6.64	$ 3.84	$ 2.95	$ 1.90
Operating costs per Boe				
Operating costs	$ 23.75	$ 19.39	$ 18.19	$ 14.95

Oil, natural gas and NGL production for our two largest fields are presented in the table below:

	Elk Hills			Wilmington		
	2022	2021	2020	2022	2021	2020
Average daily net production						
Oil (MBbl/d)	17	17	18	15	16	21
NGLs (MBbl/d)	8	10	10	—	—	—
Natural gas (MMcf/d)	75	81	90	—	—	1
Total daily net production (MBoe/d)	38	40	43	15	16	21

Our operating costs include (1) variable costs that fluctuate with production levels and (2) fixed costs that typically do not vary with changes in production levels or well counts, especially in the short term. The substantial majority of our near-term fixed costs become variable over the longer term because we manage them based on the field's stage of life and operating characteristics. For example, portions of labor and material costs, energy, workovers and maintenance expenditures correlate to well count, production and activity levels. Portions of these same costs can be relatively fixed over the near term; however, they are managed down as fields mature in a manner that correlates to production and commodity price levels. A certain amount of costs for facilities, surface support, surveillance and related maintenance can be regarded as fixed in the early phases of a program. However, as the production from a certain area matures, well count increases and daily per well production drops, such support costs can be reduced and consolidated over a larger number of wells, reducing costs per operating well. Further, many of our other costs, such as property taxes and oilfield services, are variable and will respond to activity levels and tend to correlate with commodity prices. We can quickly scale our operating costs in response to prevailing market conditions. We believe that a significant portion of our operating costs are variable over the lifecycle of our fields.

Our share of production and reserves from operations in the Wilmington field in the Los Angeles basin is subject to contractual arrangements similar to PSCs that are in effect through the economic life of the assets. Under such contracts we are obligated to fund all capital and operating costs. We record a share of production and reserves to recover a portion of such capital and operating costs and an additional share for profit. Our portion of the production represents volumes: (i) to recover our partners' share of capital and operating costs that we incur on their behalf, (ii) for our share of contractually defined base production, and (iii) for our share of remaining production thereafter. We generate returns through our defined share of production from (ii) and (iii) above. These contracts do not transfer any right of ownership to us and reserves reported from these arrangements are based on our economic interest as defined in the contracts. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline, assuming comparable capital investment and operating costs. However, our net economic benefit is greater when product prices are higher. These PSCs represented 16% of our total production for the year ended December 31, 2022.

In line with industry practice for reporting PSCs, we report 100% of operating costs under such contracts in operating costs on our consolidated statements of operations as opposed to reporting only our share of those costs. We report the proceeds from production designed to recover our partners' share of such costs (cost recovery) in our revenues. Our reported production volumes reflect only our share of the total volumes produced, including cost recovery, which is less than the total volumes produced under the PSCs. This difference in reporting full operating costs but only our net share of production equally inflates our revenue and operating costs per barrel and has no effect on our net results.

The following table presents our operating costs after adjustment for excess costs attributable to PSCs for the periods presented:

	Successor						Predecessor	
	Year ended December 31,		Year ended December 31,		November 1, 2020 - December 31, 2020		January 1, 2020 - October 31, 2020	
	2022		2021					
	(in millions)	($ per Boe)	(in millions)	($ per Boe)	(in millions)	($ per Boe)	(in millions)	($ per Boe)
Operating costs	$ 785	$ 23.75	$ 705	$ 19.39	$ 114	$ 18.19	$ 511	$ 14.95
Excess costs attributable to PSCs	(74)	(2.23)	(66)	$ (1.83)	(8)	$ (1.33)	(28)	$ (0.81)
Operating costs, excluding effects of PSCs[(a)]	$ 711	$ 21.52	$ 639	$ 17.56	$ 106	$ 16.86	$ 483	$ 14.14

(a) Operating costs, excluding effects of PSCs is a non-GAAP measure. As described above, the reporting of our PSCs creates a difference between reported operating costs, which are for the full field, and reported volumes, which are only our net share, inflating the per barrel operating costs. These amounts represent our operating costs after adjusting for this difference.

The following table reconciles our average net production to our average gross production (which includes production from the fields we operate and our share of production for fields operated by others) for the periods presented:

	Successor			Predecessor
	Year ended December 31,	Year ended December 31,	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
	2022	2021		
(MBoe/d)				
Average Daily Net Production	91	100	103	112
Partners' share under PSC-type contracts	8	8	6	5
Working interest and royalty holders' share	6	8	9	11
Other	1	1	1	1
Average Daily Gross Production	106	117	119	129

Estimated Proved Reserves and Future Net Cash Flows

The information with respect to our estimated reserves presented below has been prepared in accordance with the rules and regulations of the United States Securities and Exchange Commission (SEC).

The following tables summarize our estimated proved oil (including condensate), NGLs and natural gas reserves and PV-10 as of December 31, 2022. Our estimated volumes and cash flows were calculated using the unweighted arithmetic average of the first-day-of-the-month price for each month within the year (SEC Prices), unless prices were defined by contractual arrangements. For oil volumes, the average Brent spot price of $100.25 per barrel was adjusted for gravity, quality and transportation costs. For natural gas volumes, the average NYMEX gas price of $6.36 per MMBtu was adjusted for energy content, transportation fees and market differentials. All prices are held constant throughout the lives of the properties. The average realized prices for estimating our proved reserves as of December 31, 2022 were $97.50 per barrel for oil, $67.83 per barrel for NGLs and $7.84 per Mcf for natural gas.

Estimated reserves include our economic interests under PSCs in our Long Beach operations in the Wilmington field. Refer to *Part II, Item 8 – Financial Statements, Supplemental Oil and Gas Information* for additional information on our proved reserves.

	As of December 31, 2022				
	San Joaquin Basin	**Los Angeles Basin**	**Ventura Basin**	**Sacramento Basin**	**Total**
Proved developed reserves					
Oil (MMBbl)	155	96	—	—	251
NGLs (MMBbl)	36	—	—	—	36
Natural Gas (Bcf)	399	6	—	53	458
Total (MMBoe)[a]	257	97	—	9	363
Proved undeveloped reserves					
Oil (MMBbl)	27	16	—	—	43
NGLs (MMBbl)	2	—	—	—	2
Natural Gas (Bcf)	52	1	—	—	53
Total (MMBoe)	38	16	—	—	54
Total proved reserves					
Oil (MMBbl)	182	112	—	—	294
NGLs (MMBbl)	38	—	—	—	38
Natural Gas (Bcf)	451	7	—	53	511
Total (MMBoe)	295	113	—	9	417
Reserves to production ratio (years)[b]	12	16	0	9	13

(a) As of December 31, 2022, approximately 19% of proved developed oil reserves, 7% of proved developed NGLs reserves, 10% of proved developed natural gas reserves and, overall, 16% of total proved developed reserves are non-producing. A majority of our non-producing reserves relate to steamfloods and waterfloods where full production response has not yet occurred due to the nature of such projects.

(b) Calculated as total proved reserves as of December 31, 2022 divided by total production for the year ended December 31, 2022.

Changes to Proved Reserves

The components of the changes to our proved reserves during the year ended December 31, 2022 were as follows:

	San Joaquin Basin	Los Angeles Basin[(a)]	Ventura Basin	Sacramento Basin	Total
			(in MMBoe)		
Balance at December 31, 2021	324	140	2	14	480
Revisions related to price	3	2	—	1	6
Revisions related to performance	(5)	(7)	—	(4)	(16)
Revisions due to California regulatory changes and court challenges	(16)	(17)		(1)	(34)
Extensions and discoveries	14	2	—	—	16
Improved recovery	6	—	—	—	6
Acquisitions and divestitures	(6)	—	(2)	—	(8)
Production	(25)	(7)	—	(1)	(33)
Balance at December 31, 2022	295	113	—	9	417

(a) Includes proved reserves related to PSCs of 92 MMBoe and 111 MMBoe at December 31, 2022 and 2021, respectively.

Revisions related to price – We had net positive price-related revisions of 6 MMBoe primarily resulting from a higher commodity price environment in 2022 compared to 2021. The price revision reflects the extended economic lives of our fields, estimated using 2022 SEC pricing. Additionally, we have experienced higher vendor-related pricing and compensation-related cost increases due to inflation.

Revisions related to performance – We had 16 MMBoe of net negative performance-related revisions which included negative performance-related revisions of 31 MMBoe and positive performance-related revisions of 15 MMBoe. Our negative performance-related revisions primarily were due to wells and incremental waterflood response that underperformed forecasts and removal of proved undeveloped locations due to unsuccessful drilling results in certain areas. Our positive performance-related revisions primarily related to better-than-expected well performance and addition of proved undeveloped locations due to positive drilling results in certain areas. The majority of these revisions were located in the San Joaquin and Los Angeles basins.

Revisions due to California regulatory changes and court challenges – We had 34 MMBoe of negative revisions to our proved reserves due to the impact of California regulatory changes and court challenges on our development plans. Of this amount, negative revisions of 20 MMBoe of proved reserves were due to the uncertainty of the outcome of the referendum and potential impact of Senate Bill No. 1137. The majority of these volumes are in the LA Basin. Negative revisions of 14 MMBoe to our proved reserves were due to challenges to Kern County's ability to issue well permits in reliance on an existing EIR for CEQA purposes. The volumes affected by these court challenges are in Kern County. See *Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

Extensions and discoveries – We added 16 MMBoe from extensions and discoveries resulting from successful drilling and workovers in the San Joaquin and Los Angeles basins.

Acquisitions and Divestitures – We had a reduction of 8 MMBoe which primarily related to our Lost Hills divestiture. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Divestitures and Acquisitions* for more information on these transactions.

Proved Undeveloped Reserves

The total changes to our proved undeveloped reserves during the year ended December 31, 2022 were as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in MMBoe)		
Balance at December 31, 2021	45	30	—	—	75
Revisions related to price	1	(2)	—	—	(1)
Revisions related to performance	(5)	2	—	—	(3)
Revisions due to California regulatory changes and court challenges	(12)	(11)	—	—	(23)
Extensions and discoveries	10	1	—	—	11
Improved recovery	6	—	—	—	6
Divestitures	(2)	—	—	—	(2)
Transfers to proved developed reserves	(5)	(4)	—	—	(9)
Balance at December 31, 2022	38	16	—	—	54

Revisions related to price – We had 1 MMBoe of net negative price-related revisions. Positive price-related revisions of 2 MMBoe were offset by 3 MMBoe of negative cost recovery barrels in our PSCs.

Revisions related to performance – We had 3 MMBoe of net negative performance-related revision which included 4 MMBoe positive performance-related revisions and negative performance-related revisions of 7 MMBoe. Our positive performance-related revisions of 4 MMBoe primarily related to better-than-expected well performance and the addition of proved undeveloped locations due to positive drilling results in certain areas. The positive revision also included proved undeveloped reserves which were added to our five-year development plan in 2022. Our negative performance-related revisions primarily related to unsuccessful drilling results in certain areas. The majority of these revisions were located in the San Joaquin and Los Angeles basins.

Revisions due to California regulatory changes and court challenges – We removed 23 MMBoe from proved undeveloped reserves due to the impact of the regulatory changes and court challenges on our development plans as discussed above. 11 MMBoe of proved undeveloped reserves were affected by Senate Bill No. 1137. 12 MMBoe of proved undeveloped reserves were affected by the Kern County court challenges. These revisions are largely due to the uncertainty of near term permitting of drilling projects and the deferral of development of certain projects beyond 5 years. The volumes impacted are in Kern County. See *Regulation of the Industries in Which We Operate, Regulations of Exploration and Production Activities*.

Extensions and discoveries – We added 11 MMBoe of proved undeveloped reserves through extensions and discoveries, as a result of successful drilling and workover programs in the San Joaquin and Los Angeles basins.

Transfers to proved developed reserves – We converted 9 MMBoe of proved undeveloped reserves to proved developed reserves in the San Joaquin and Los Angeles basins. This resulted in a conversion rate of approximately 12% of our beginning-of-year proved undeveloped reserves, with an investment of approximately $127 million of drilling and completion capital. We believe we will have sufficient capital to develop all year end 2022 proved undeveloped reserves within five years of their original booking date.

PV-10 and Standardized Measure

PV-10 of cash flows is a non-GAAP financial measure and represents the year-end present value of estimated future cash inflows from proved oil and natural gas reserves, less future development and operating costs, discounted at 10% per annum to reflect the timing of future cash flows and using SEC Prices. Calculation of PV-10 does not give effect to derivative transactions. Our PV-10 is computed on the same basis as our standardized measures of future net cash flows, the most comparable measure under GAAP, but does not include the effects of future income taxes on future net cash flows. Neither PV-10 nor Standardized Measure should be construed as the fair value of our oil and natural gas reserves. Standardized Measure is prescribed by the SEC as an industry standard asset value measure to compare reserves with consistent pricing, costs and discount assumptions. PV-10 facilitates the comparisons to other companies as it is not dependent on the tax-paying status of the entity.

	As of December 31, 2022 (in millions)
Standardized measure of discounted future net cash flows	$ 6,726
Present value of future income taxes discounted at 10%	2,493
PV-10 of cash flows[(a)]	$ 9,219

(a) The average realized prices for estimating our PV-10 of cash flow as of December 31, 2022 were $97.50 per barrel for oil, $67.83 per barrel for NGLs and $7.84 per Mcf for natural gas.

Reserves Evaluation and Review Process

Our estimates of proved reserves and related discounted future net cash flows as of December 31, 2022 were made by our technical personnel, comprised of reservoir engineers and geoscientists, with the assistance of operational and financial personnel and are the responsibility of management. The estimation of proved reserves is based on the requirement of reasonable certainty of economic producibility and management's funding commitments to develop the reserves. Reserves volumes are estimated by forecasts of production rates, operating costs and capital investments. Price differentials between specified benchmark prices and realized prices and specifics of each operating agreement are then applied against the SEC Price to estimate the net reserves. Operating and capital costs are forecast using the current cost environment applied to expectations of future operating and development activities related to the proved reserves. See *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Estimates* for further discussion of uncertainties inherent in the reserve estimates.

Proved developed reserves are those volumes that are expected to be recovered through existing wells with existing equipment and operating methods, for which the incremental cost of any additional required investment is relatively minor. Proved undeveloped reserves are those volumes that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required.

Our Vice President of Reserves has primary responsibility for overseeing the preparation of our reserves estimates. With over 25 years of technical and leadership experience in the oil and gas industry, she has been involved with all stages of petroleum exploration and development from appraisal of new discoveries to enhanced recovery methods in mature fields. She holds a Master of Business Administration from Pepperdine University, as well as bachelor's and master's degrees in Geology from the University of California, Santa Barbara.

We have an Oil and Gas Reserves Review Committee (Reserves Committee), consisting of senior corporate officers, which reviewed and approved our oil and natural gas reserves for 2022. The Reserves Committee annually reports its findings to the Audit Committee.

Audits of Reserves Estimates

Ryder Scott and Netherland, Sewell & Associates, Inc. (NSAI) were engaged to provide independent audits of our reserves estimates for our fields. For the year ended December 31, 2022, Ryder Scott audited 49% of our total proved reserves. NSAI audited 36% of our total proved reserves. Collectively, 85% of our proved reserves were audited in 2022.

Our independent reserve engineers examined the assumptions underlying our reserves estimates, adequacy and quality of our work product and estimates of future production rates. They also examined the appropriateness of the methodologies employed to estimate our reserves as well as their categorization, using the definitions set forth by the SEC, and found them to be appropriate. As part of their process, they developed their own independent estimates of reserves for those fields that they audited. When compared on a field-by-field basis, some of our estimates were greater and some were less than the estimates of our independent reserve engineers. Given the inherent uncertainties and judgments in estimating proved reserves, differences between our estimates and those of our independent reserve engineers are to be expected. The aggregate difference between our estimates and those of the independent reserve engineers was less than 10%, which was within the Society of Petroleum Engineers (SPE) acceptable tolerance.

In the conduct of the reserves audits, our independent reserve engineers did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, crude oil and natural gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the fields and sales of production. However, if anything came to the attention of our independent auditors that brought into question the validity or sufficiency of any such information or data, they would not rely on such information or data until it had resolved its questions relating thereto or had independently verified such information or data. Our independent reserve engineers determined that our estimates of reserves have been prepared in accordance with the definitions and regulations of the SEC as well as the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE, including the criteria of “reasonable certainty,” as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions. Both of our independent reserve engineers issued an unqualified audit opinion on the applicable portions of our proved reserves as of December 31, 2022, which are attached as Exhibit 99.1 and 99.2, respectively, to this Form 10-K and incorporated herein by reference.

Ryder Scott qualifications – The primary technical engineer responsible for our audit has more than 45 years of petroleum engineering experience, the majority of which has been in the estimation and evaluation of reserves. He serves on the Ryder Scott Executive Committee and the Board of Directors and is a registered Professional Engineer in the state of Texas.

NSAI qualifications – The primary technical engineer responsible for our audit has more than 21 years of petroleum engineering experience, with the majority spent evaluating California properties, and is a registered Professional Engineer in the state of Texas. The primary geoscientist for the audit has more than 25 years of experience practicing petroleum geoscience and is a Licensed Professional Geoscientist in the state of Texas.

Drilling Statistics

The following table sets forth information on our net exploration and development wells drilled and completed during the periods indicated, regardless of when drilling was initiated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value. We refer to gross wells as the total number of wells in which interests are owned, including outside operated wells. Net wells represent wells reduced to our fractional interest.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total Net Wells
2022					
Productive					
Exploratory	—	—	—	—	—
Development	114.3	35.0	—	—	149.3
Dry					
Exploratory	—	—	—	—	—
Development	—	—	—	—	—
2021					
Productive					
Exploratory	—	—	—	—	—
Development	109.4	6.5	—	—	115.9
Dry					
Exploratory	—	—	—	—	—
Development	—	—	—	—	—
2020					
Productive					
Exploratory	—	—	—	—	—
Development	4.0	4.5	—	0.4	8.9
Dry					
Exploratory	—	—	—	—	—
Development	—	—	—	—	—

The following table sets forth information on our development wells where drilling was either in progress or pending completion as of December 31, 2022.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total Net Wells
Gross	3.0	3.0	—	—	6.0
Net	3.0	2.8	—	—	5.8

Productive Wells

Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce at a reasonable rate of return. Our average working interest in our producing wells was 92% as of December 31, 2022. Wells are categorized based on the primary product they produce.

The following table sets forth our productive oil and natural gas wells (both producing and capable of production) as of December 31, 2022, excluding wells that have been idle for more than five years:

	As of December 31, 2022			
	Productive Oil Wells		Productive Natural Gas Wells	
	Gross[(a)]	Net[(b)]	Gross[(a)]	Net[(b)]
San Joaquin Basin	7,312	6,802	158	156
Los Angeles Basin	1,730	1,640	—	—
Ventura Basin	20	20	—	—
Sacramento Basin	—	—	920	849
Total	9,062	8,462	1,078	1,005
Multiple completion wells included in the total above	126	123	17	15

(a) The total number of wells in which interests are owned.
(b) Net wells include wells reduced to our fractional interest.

Exploration Inventory

We have had minimal investment in exploration activity in recent years, and our 2023 capital plan does not allocate any capital towards exploration drilling.

Marketing Arrangements

Crude Oil – We sell nearly all of our crude oil to California refiners. Substantially all of our crude oil production is connected to third-party pipelines and California refining markets via our gathering systems. We do not refine or process the crude oil we produce and do not have any significant long-term transportation arrangements.

The prices paid by California refiners are typically based on local third-party postings that are closely tied to Brent prices. International waterborne-based Brent prices are relevant because there is limited crude pipeline infrastructure available to transport crude overland from other parts of the United States into California. We believe that these limitations will continue to contribute to higher realizations in California than most other U.S. oil markets for comparable grades.

Natural Gas – We sell all of our natural gas not used in our operations into the California market. A majority of these sales are done on a daily basis using index based prices. Natural gas prices and differentials are strongly affected by local market fundamentals, such as storage capacity and the availability of transportation capacity in the market and producing areas. Transportation capacity influences prices because California imports more than 90% of its natural gas from other states and Canada. As a result, we typically obtain higher realizations relative to out-of-state producers due to lower transportation costs on the delivery of our natural gas.

In addition to selling natural gas, we also use natural gas in steam generation for our steamfloods and power generation. As a result, the positive impact of higher natural gas prices is partially offset by higher operating costs of our steamflood projects and power generation, but higher prices still have a net positive effect on our operating results due to net higher revenue. Conversely, lower natural gas prices lower these operating costs but have a net negative effect on our financial results.

We currently hold transportation capacity contracts to transport all of our natural gas volumes for multiple years.

NGLs – NGL prices vary by liquid type and realizations are closely correlated to the different commodity prices to which they relate. Prices can also fluctuate due to the demand for certain chemical products (for which NGLs are used as feedstock) and due to infrastructure constraints and seasonality. Finally, our results are also affected by the performance of our natural gas-processing plants. We process our wet gas to extract NGLs and other natural gas byproducts. We then deliver dry gas to pipelines and separately sell the remaining products as NGLs. The efficiency with which we extract liquids from the wet gas stream affects our operating results. Our natural gas-processing plants also facilitate access to third-party delivery points near the Elk Hills field.

We currently have a ship-or-pay pipeline transportation contract for 6,500 barrels per day of NGLs through March 2023. Our contract to transport NGLs requires us to cash settle any shortfall between the committed quantities and volumes actually shipped. We have met all our shipping commitments under this contract.

Electricity – A portion of the electrical output of the Elk Hills power plant is used by Elk Hills and other nearby production fields. This provides a reliable source of power. We sell remaining electrical output to the wholesale power market and a local utility. We also sell the remaining capacity to community choice aggregates and other local utilities.

Delivery Commitments

We have commitments to certain refineries and other buyers to deliver oil, natural gas and NGLs. As of December 31, 2022, we had oil delivery commitments of 10 MMBbl in 2023, 3 MMBbl in 2024 and 1 MMBbl in 2025, NGL delivery commitments of 1 MMBbl through March 2023 and natural gas delivery commitments of 13 Bcf through December 2023. We generally have significantly more production than the amounts committed for delivery and have the ability to secure additional volumes of products as needed. These commitments are typically index-based contracts with prices set at the time of delivery.

Derivatives

We protect our operating cash flow from volatility in the commodities market through our hedging strategy. Prior to May 2022, our Revolving Credit Facility required us to maintain certain levels of hedges regardless of our leverage. We also entered into incremental hedges above and beyond these requirements for certain time periods. In certain circumstances, these hedges (including hedges entered into by us in 2020 to comply with covenants in our Revolving Credit Facility) prevent us from realizing the full benefits of price increases. Following an amendment to our Revolving Credit Facility in April 2022, we are only required to maintain hedges in the event the ratio of our consolidated total debt to consolidated EBITDAX as defined in our Credit Agreement exceeds 1:1. We continuously evaluate our hedging strategy to take into account changes in prevailing market prices and conditions.

Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives* for more information on our commodity contracts.

Our Principal Customers

We sell crude oil, natural gas and NGLs to marketers, California refineries and other purchasers that have access to transportation and storage facilities. Our ability to sell our products can be affected by factors that are beyond our control and cannot be accurately predicted. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 1 Nature of Business, Summary of Significant Accounting Policies and Other* for more information on our customers.

Title to Properties

As is customary in the oil and natural gas industry for acquired properties, we initially conduct a high-level review of the title to our properties at the time of acquisition. Individual properties may be subject to ordinary course burdens that we believe do not materially interfere with the use or affect the value of such properties. Burdens on properties may include customary royalty or net profits interests, liens incident to operating agreements and tax obligations or duties under applicable laws, or development and abandonment obligations, among other items. Prior to the commencement of drilling operations on those properties, we typically conduct a more thorough title examination and may perform curative work with respect to significant defects. We generally will not commence drilling operations on a property until we have cured known title defects that are material to the project. For additional information on properties which secure our debt, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Debt.*

Competition

Our competitors are primarily other exploration and production companies that produce oil, natural gas and NGLs. We compete locally against small independent producers and major international oil companies who operate in California. We also compete with foreign oil and gas companies because California imports approximately 75% of the oil it consumes. We believe that our proximity to the California refineries gives us a competitive advantage over importers due to lower transportation costs. Further, California refineries are generally designed to process crude with similar characteristics to the low-carbon intensity oil produced from our fields. The California natural gas market is serviced from a network of pipelines, including interstate and intrastate pipelines. We deliver our natural gas to customers using our firm capacity contracts.

We compete for third-party services to profitably develop our assets, to find or acquire additional reserves, to sell our production and to find and retain qualified personnel. Higher commodity prices could intensify competition for drilling and workover rigs, pipe, other oil field equipment and personnel. In 2022, we experienced increased costs due to inflation. However, in the current environment, we anticipate modest price increases for materials and services as contracts are renewed in the future. We believe our relative size and activity levels, compared to other in-state producers, favorably influences the pricing we receive from third-party providers in the markets in which we operate.

We also face competition in our oil and natural gas operations from other sources of energy, including wind and solar power. These products compete directly with the electricity we generate from our power plants and indirectly as substitutes for oil, natural gas and NGLs. We expect competition from these sources to intensify in the future due to technological advances and as California continues to develop renewable energy and implements climate-related policies.

In our carbon management business, we compete with other potential storage providers to acquire and develop storage reservoirs and enter into agreements with existing and future emission sources.

Infrastructure

The infrastructure used in our operations, including plants and facilities located in the Wilmington field, is presented below:

Description	Quantity	Unit	Capacity		
			San Joaquin Basin	Other Basins	Total
Gas Processing Plants[(a)]	6	MMcf/d	525	18	543
Power Plants[(b)]	3	MW	595	48	643
Steam Generators/Plants[(c)]	>30	MBbl/d	150	—	150
Compressors	>300	MHp	320	21	341
Water Management Systems[(c)]		MBw/d	1,900	1,980	3,880
Water Softeners[(c)]	16	MBw/d	125	—	125
Oil and NGL Storage[(d)]		MBbls	408	195	603
Pipelines[(e)]		Miles			>8,000

(a) Includes the Elk Hills cryogenic gas plant with a capacity of 200 MMcf/d of inlet gas and two low temperature separation plants used as backup facilities. Our natural gas processing facilities are interconnected via pipelines to nearby third-party rail and trucking facilities, with access to various North American NGL markets. In addition, we have truck rack facilities coupled with a battery of pressurized storage tanks at our natural gas processing facilities for NGL sales to third parties.

(b) Includes our 550-megawatt combined-cycle Elk Hills power plant, located adjacent to the Elk Hills natural gas processing facility and typically generates all the electricity needed by our Elk Hills field and certain contiguous operations in the San Joaquin basin. We utilize approximately a third of its capacity for operations and our subsidiary sells the excess to the grid and to a local utility. Also included is a 45-megawatt cogeneration facility at Elk Hills that provides additional flexibility and reliability to support field operations and a 48-megawatt power generating facility that is part of the Long Beach Unit located in the Los Angeles basin.

(c) We own, control and operate water management and steam-generation infrastructure. We soften and self-supply water to generate steam, reducing our operating costs. This is integral to our operations in the San Joaquin basin and supports our high-margin oil fields.

(d) Our tank storage capacity throughout California gives us flexibility for a period of time to store crude oil and NGLs, allowing us to continue production and avoid or delay any field shutdowns in the event of temporary power, pipeline or other shutdowns.

(e) Our pipelines are dedicated almost entirely to collecting our oil and natural gas production and are in close proximity to field-specific facilities such as tank settings or central processing sites. Our oil pipelines connect to multiple third-party transportation pipelines. In addition, virtually all of our natural gas facilities connect with major third-party natural gas pipeline systems.

Carbon Management Business

In 2021, we adopted a 2045 Full-Scope Net Zero goal to achieve permanent storage of captured or removed carbon emissions in a volume equal to all of our Scope 1, 2 and 3 emissions by 2045. Our climate-related goal could be modified as standards and rules develop related to greenhouse gas emissions, and the potential separation of our carbon management business would also affect our ability to reach this goal.

We have formed a carbon management business to pursue CCS projects that are directly-sited or within close proximity to significant sources of CO_2 emissions in California. We intend to manage our carbon management business on a stand-alone basis over time. We expect that this will provide greater flexibility to consider strategic options, including the potential separation from our E&P business. To facilitate that goal, we have created a new board of directors at Carbon TerraVault, initially comprised of three of our directors: Mark A. (Mac) McFarland, Andrew Bremner and James Chapman.

EPA Class VI Permits and CCS Projects

We are in the early stages of developing several CCS projects in California. To date, we have submitted Class VI permit applications to the EPA for two permanent sequestration projects at our Elk Hills field. We have also submitted permit applications for two permanent sequestration projects in the Sacramento Basin.

We continue to evaluate potential storage projects in California. One of our storage projects is being jointly developed through the Carbon TerraVault JV. Several other projects are being considered by the Carbon TerraVault JV for future development. If Brookfield elects to participate in a project, our upfront costs to evaluate and permit that project will be subsequently recovered through Brookfield's investment in the Carbon TerraVault JV. We may also pursue the development of CCS projects independently of the Carbon TerraVault JV if Brookfield elects not to participate.

In 2022, we executed two carbon dioxide management agreements (CDMAs) with emitters to provide permanent carbon storage. The CDMAs frame the material economics and terms of the project and include conditions precedent to close. The CDMAs are also subject to negotiation of definitive documents and a final investment decision. One of the CDMAs relates to a project that will be developed through the Carbon TerraVault JV. We are separately in discussions with other potential emitters to enter into joint venture or other commercial arrangements with respect to CCS projects.

Once completed, we expect that our Carbon TerraVault CCS projects will inject CO_2 captured from industrial sources into subsurface reservoirs and permanently store CO_2 deep underground. As part of our commitment to carbon management, we are also evaluating the feasibility of developing a carbon capture system for our 550-megawatt Elk Hills power plant (CalCapture) and pursuing a U.S. Department of Energy grant for the development of a direct air capture hub in California.

We expect that the size and scope of our projects providing these and similar services and capital spent on such projects will continue to grow given our strategy of expansion into these services and the development of our carbon management business as a stand-alone business. For more information about the risks involved in our carbon management business, see *Part I, Item 1A – Risk Factors.*

Carbon TerraVault JV

In August 2022, we entered into the Carbon TerraVault JV with Brookfield for the further development of our carbon management business. We hold a 51% interest in the Carbon TerraVault JV and Brookfield holds a 49% interest. Brookfield has committed an initial $500 million to invest in CCS projects that are jointly approved through the Carbon TerraVault JV. At the formation of the Carbon TerraVault JV, we contributed rights to inject CO_2 into the 26R reservoir in our Elk Hills field for permanent CO_2 storage (26R reservoir) and Brookfield committed to make an initial investment of $137 million, payable in three equal installments with the last two installments subject to the achievement of certain milestones. Brookfield contributed the first $46 million installment of their initial investment to the Carbon TerraVault JV during the year ended December 31, 2022. This amount may, at our sole discretion, be distributed to us or used to satisfy future capital contributions, among other items. The parties have certain put and call rights with respect to the 26R reservoir if certain milestones are not met. Future storage projects for Brookfield's initial commitment are subject to approval of the joint venture, including Brookfield.

The Carbon TerraVault JV has an option to participate in certain projects that involve the capture, transportation and storage of CO_2 in California. This option expires upon the earlier of (1) August 2027, (2) when a final investment decision has been approved by the Carbon TerraVault JV for storage projects representing in excess of 5 MMTPA in the aggregate, or (3) when Brookfield has made contributions to the joint venture in excess of $500 million (unless Brookfield elects to increase its commitment). Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Investment in Unconsolidated Subsidiary and Related Party Transactions* for more information on our Carbon TerraVault JV.

Human Capital Management

Our employees are our most valuable asset and we strive to provide a safe and healthy workplace, development opportunities and financial rewards, ensuring focus on fair and equitable treatment. We believe our core values of Character, Responsibility and Commitment and our comprehensive business and ethical conduct policies sustain shareholder value.

Our comprehensive business and ethical conduct policies apply to all directors, officers and employees, each of whom personally commits to following our code of conduct and our corporate policies, as well as to suppliers and vendors working in our operations. Our position is that no business goal is worth our employees compromising their integrity or our shared values.

As of December 31, 2022, we had approximately 1,060 employees, all in the United States. Of the total 1,060 employees, 45 full-time equivalents are focused on our carbon management business. Approximately 50 of our employees are covered by a collective bargaining agreement. We also utilize the services of many third-party contractors throughout our operations.

Continued Employee Development

Employee development opportunities are provided to enhance leadership development and expand career opportunities. Our employees undergo mandatory annual training on our policies including health and safety, business ethics, harassment, IT security and others. Our mandatory training reinforces our company-wide commitment to operate in accordance with all applicable laws, rules and regulations and to sustain a diverse and empowered workforce comprising of our employees and those of our suppliers, vendors and joint ventures. In addition to training, our employees receive regular performance and career development discussions from their direct managers. All employees receive annual performance reviews.

Our largest development initiatives include the Future Leaders Development Program with the University of California, Los Angeles (UCLA) Anderson School; our Intrepid Women's Program, a program of coaching and development circles for women; and ELEVATE, a manager workshop on communication styles and culture changing behaviors to develop our future leaders.

We have taken steps to promote the development of a pipeline of candidates as we develop our carbon management business. In 2022, we pledged $2.5 million to fund several Kern County initiatives with Kern Community College District (Kern CCD) and California State University, Bakersfield (CSUB) to help advance the energy transition and further benefit local communities. We will collaborate with Kern CCD to establish the CRC Carbon Management Institute, a first-of-its-kind initiative that will empower local private and public partnerships to lead the way in defining how collaboration between education and industry can positively impact communities. Funding will also be used for research and development, community outreach and education, workforce training and education, and carbon management academics that will focus on advancing CCS and emerging technologies. Additionally, CSUB will launch the CRC Energy Transition Lecture Series on relevant topics and emerging issues related to CCS and technologies that will lead the way to achieving a net zero future. Finally, the CRC Carbon TerraVault Scholarship will be established to help provide students with academic opportunities.

Diversity, Equity and Inclusion

Our goal is to foster an open and diverse culture and we are committed to advancing women and minorities in our workplace. We believe increasing diversity, equity and inclusion (DE&I) will help us achieve success through better retention rates, higher innovation, and increased productivity. We have implemented a 2030 ethnic, racial and gender diversity leadership goal that prioritizes ethnic, racial and gender diversity in company leadership positions and on the Board of Directors. Our goal is three pronged, to maintain greater than 20% ethnically and racially diverse professionals in leadership positions, increase gender diverse professionals in leadership positions to 30% and maintain current Board composition with at least 30% ethnically, racially and gender diverse Board members. We also established an Advisory Council focused on career development, promotion, recruitment and retention to help ensure that we meet our DE&I goals. In 2022, we had all employees attend DE&I training to reinforce an open and diverse culture.

The table below approximates our self-reported gender diverse and ethnically and racially diverse employees and members of our Board of Directors as of December 31, 2022.

	Gender Diverse	Ethnically and Racially Diverse
All Employees	20%	40%
Managers	21%	23%
Executives	22%	26%
Board of Directors	33%	33%

Employee Safety

Our unwavering commitment to health, safety and the environment defines how we operate our business. We prepare our workforce to work safely through comprehensive training, safe work practices, technology and rigorous maintenance and asset integrity programs. Each year, we set a threshold TRIR as a quantitative metric that directly impacts incentive compensation for all of our employees. We have achieved exemplary, steadily improved safety performance over the last several years by promoting a culture of safety where all employees, contractors and vendors are empowered with Stop Work Authority to cease any activity – without repercussions – to prevent a safety or environmental accident.

Engagement and Retention

We survey our employees annually to ensure employee sentiment is collected and heard throughout the year allowing us to assess engagement levels and drivers to determine areas of improvement to enhance engagement and retention. The results of the engagement surveys are reviewed by senior management and our Board of Directors. Senior leadership also host regular townhalls so employees can engage with them through question and answer sessions.

We provide our employees industry competitive base wages and annual and long-term incentive compensation opportunities, as well as matching and profit-sharing retirement contributions to employees' 401(k) accounts; comprehensive health benefits; life, disability and accident insurance coverages; sick pay, paid holidays, paid parental leave and vacation; employee assistance for confidential counseling services, a wellness program to promote the well-being of our employees and their families; and various group discount programs. Our employee stock purchase program allows our employees to purchase shares of our common stock at a discounted price. We also provide options for alternate work schedules, flexible work hours, part-time work options and telecommuting.

Regulation of the Industries in Which We Operate

Our operations are subject to a wide range of federal, state and local laws and regulations. Those that specifically relate to oil and natural gas exploration and production are described in this section.

Regulation of Exploration and Production Activities

Well Permitting

CalGEM is California's primary regulator of the oil and natural gas production industry on private and state lands, with additional oversight from the State Lands Commission's administration of state surface and mineral interests. From time to time we have experienced significant delays with respect to obtaining drilling permits from CalGEM for our operations. A variety of factors outside of our control can lead to such delays. CalGEM has not issued any permits for new production wells to any operators since December 2022.

CalGEM currently requires an operator to identify the manner in which the California Environmental Quality Act (CEQA) has been satisfied prior to issuing various state permits, typically through either an environmental review or an exemption by a state or local agency. In Kern County, this requirement has typically been satisfied by complying with the local oil and natural gas ordinance which was supported by an Environmental Impact Report (EIR) certified by the Kern County Board of Supervisors in 2015.

Our operations in Kern County have been subject to significant uncertainty over the past several years as a result of ongoing challenges to the County's ability to rely on an existing EIR to meet the County's obligations under CEQA. In December 2015 several groups challenged the sufficiency of the EIR for satisfying CEQA requirements in Kern County for oil and natural gas permit approvals (Kern County EIR Litigation). In March 2018 a trial court (Trial Court) found that the EIR inadequately analyzed the environmental impacts to rangeland and road paving mitigation for purposes of well work and rejected the plaintiffs' other CEQA claims. The plaintiffs appealed. In February 2020, the California Fifth District Appellate Court (Appellate Court) ruled that the plaintiffs' other CEQA claims had merit and ordered Kern County to rescind the Zoning Ordinance and cease issuing permits. In March 2021, Kern County's Board of Supervisors approved a revised Zoning Ordinance (the Revised Ordinance) and certified a Supplemental Recirculated Environmental Impact Report (SREIR) for purposes of satisfying CEQA requirements with respect to the issuance of oil and natural gas permits. A suit was subsequently filed that same month challenging the sufficiency of the SREIR. In October 2021, the Trial Court ordered Kern County to cease using the existing EIR to meet CEQA requirements until it determined that the Revised Ordinance complied with CEQA requirements. The Trial Court subsequently identified four deficiencies in the SREIR that needed correction to conform to CEQA. In November 2022, upon the correction of those deficiencies to the Trial Court's satisfaction, the Trial Court lifted the suspension on Kern County's ability to rely on the existing SREIR to meet CEQA requirements in Kern County (the Discharge Order). In December 2022, the Trial Court denied a motion to stay the Discharge Order. The plaintiffs appealed the judgment and Discharge Order and filed a petition requesting a stay of the ordinance pending resolution of the merits of the appeal.

On January 26, 2023, the Appellate Court issued a preliminary order on the petition reinstating a suspension of Kern County's ability to rely on the existing SREIR to meet CEQA requirements pending the outcome of a final order determining whether oil and natural gas permitting shall remain suspended for the duration of the appeals process. That order is still pending.

We intend to address CEQA compliance for our oil and natural gas permits in Kern County through alternative pathways. However, this will be a lengthy process and we cannot predict whether this approach will ultimately be successful. As a result of these issues and current lack of permits with respect to our Kern County properties, we do not currently plan to drill and complete any additional wells within Kern County until permitting is resumed in Kern County, which may be later in the 2024 calendar year. However, there is no certainty that we will obtain permits on that timeline or at all, which may further adversely affect our future development plans, proved undeveloped reserves, business, operations, cash flows, financial position and results of operations. Approximately 71% of our proved undeveloped reserves or 9% of our total proved reserves relate to wells to be drilled in Kern County beginning in 2024 for which we would need to obtain permits.

The California Legislature and Governor have significantly increased the jurisdiction, duties and enforcement authority of CalGEM, the State Lands Commission and other state agencies with respect to oil and natural gas activities in recent years through legislation and policy pronouncements. For example, 2019 state legislation expanded CalGEM's duties effective on January 1, 2020 to include public health and safety and reducing or mitigating greenhouse gas emissions while meeting the state's energy needs, and will require CalGEM to study and prioritize idle wells with emissions, evaluate costs of abandonment, decommissioning and restoration, and review and update associated indemnity bond amounts from operators if warranted, up to a specified cap which may be shared among operators. Other 2019 legislation specifically addressed oil and natural gas leasing by the State Lands Commission, including imposing conditions on assignment of state leases, requiring lessees to complete abandonment and decommissioning upon the termination of state leases, and prohibiting leasing or conveyance of state lands for new oil and natural gas infrastructure that would advance production on certain federal lands such as national monuments, parks, wilderness areas and wildlife refuges.

CalGEM and other state agencies have also significantly revised their regulations, regulatory interpretations and data collection and reporting requirements. CalGEM issued updated regulations in April 2019 governing management of idle wells and underground fluid injection, which include specific implementation periods. The updated idle well management regulations require operators to either submit annual idle well management plans describing how they will plug and abandon or reactivate a specified percentage of long-term idle wells or pay additional annual fees and perform additional testing to retain greater flexibility to return long-term idle wells to service in the future. The updated underground injection regulations address injection approvals, project data requirements, testing of injection wells, monitoring and reporting requirements with respect to injection parameters, containment and incident response, among other topics.

In addition, certain local governments have proposed or adopted ordinances that would restrict certain drilling activities in general and well stimulation, completion or injection activities in particular, impose setback distances from certain other land uses, or ban such activities outright. For example, both the City and the County of Los Angeles have voted to prohibit new oil and natural gas wells and phase out existing wells over a number of years. Our operations in unincorporated areas of Los Angeles are not affected by these bans, and we do not anticipate a material impact from these bans to our future drilling operations as we have no drilling plans or proved undeveloped reserves within the area that would be covered by these bans. However, from time to time, other local governments in California have sought to enact similar bans and others may seek to do so in the future. For example, a similar ban was previously proposed in Monterey County, where we own mineral rights but have no production, before being declared to be preempted by state and federal regulation. Other local governments have sought to ban natural gas or the transportation of natural gas through their cities. The City of Antioch declined to extend our franchise agreement for a natural gas pipeline through its city. Several companies, including CRC, have challenged the city's inconsistent and arbitrary approach to natural gas approvals.

Setbacks

On September 16, 2022, the Governor of California signed Senate Bill No. 1137 into law, which established 3,200 feet as the minimum distance between new oil and natural gas production wells and certain sensitive receptors such as homes, schools and businesses open to the public effective January 1, 2023. On January 6, 2023, CalGEM's emergency regulations to support implementation of Senate Bill No. 1137 were approved by the Office of Administrative Law and final regulations were published. The regulations included applicable requirements of notice to property owners and tenants regarding the work performed and offering the sampling of test water wells or surface water before and after drilling; the contents of required notices for new production facilities; the annual submission of a sensitive receptor inventory and sensitive receptor map and the contents and format of the same; and the requirements of statements where operators have determined a location not to be within a health protection zone. Additional provisions of Senate Bill No. 1137 include, among others, the imposition of health, safety and environmental controls applicable to both current and new wells located within this distance of sensitive receptors related to noise, light, and dust pollution controls and air emission monitoring, and the immediate suspension of operations at production facilities determined to not be in compliance with certain air emission requirements. In December 2022, proponents of a voter referendum (the Referendum) collected more than the requisite number of signatures required to put Senate Bill No. 1137 on the 2024 ballot. On February 3, 2023, the Secretary of State of California certified the signatures and confirmed that the Referendum qualifies for the November 2024 ballot. Accordingly, Senate Bill No. 1137 is stayed until it is put to a vote, although any stay could be delayed if there are legal challenges to the Secretary of State's certification. In addition, even during the stay, CalGEM could attempt to initiate rulemaking with regard to setbacks.

The majority of our production is in rural areas in the San Joaquin basin and is unlikely to be affected by Senate Bill No. 1137 should the outcome of the Referendum result in the bill being implemented. We would not expect the implementation of this law to result in any change in our existing proved developed producing reserves or current production rates or any material change to the timing of plugging and abandonment liabilities. However, there is significant uncertainty with respect to our ability to develop proved undeveloped reserves within the setback zones established by Senate Bill No. 1137. As a result, we have removed from our reserves any proved undeveloped reserves that are located within setback zones, except for those reserves for which we have existing drilling permits and intend to develop prior to the November 2024 ballot. This resulted in a reduction to the net present value of our proved undeveloped reserves by 24% and our overall proved reserves by 4% as of December 31, 2022.

Pipeline Transportation

Federal and state pipeline regulations have also been recently revised. CalGEM imposed more stringent inspection and integrity management requirements in 2019 and 2020 with respect to certain natural gas pipelines in specified locations, with additional regulations anticipated in 2022 regarding digital mapping of such lines. The Office of the State Fire Marshal adopted regulations in 2020 to require risk assessment of various oil lines in the coastal zone, followed by retrofitting of certain of those lines with the best available control technology to mitigate oil spills over a specified implementation period. Finally, the federal PHMSA has, from time to time, issued new regulations expanding or otherwise revising pipeline integrity requirements. For example, in November 2021, PHMSA issued a final rule imposing safety regulations on an aggregate of approximately 400,000 miles of previously unregulated onshore gas gathering lines across the United States that, among other things, will impose criteria for inspection and repair of fugitive emissions, extend reporting requirements to all gas gathering operators and apply a set of minimum safety requirements to certain gas gathering pipelines with large diameters and high operating pressures. And, in August 2022, PHMSA finalized additional pipeline safety rules, which adjusted the repair criteria for pipelines in high consequence areas, created new criteria for pipelines in non-high consequence areas, and strengthened integrity management assessment requirements, among other items.

Water Injection

Our operations in the Wilmington Oil Field utilize injection wells to reinject produced water pursuant to waterflooding plans. These operations are subject to regulation by the City of Long Beach and CalGEM. We are currently in discussions with the City of Long Beach and CalGEM with respect to what injection well pressure gradient complies with CalGEM's requirements for the protection of underground sources of drinking water, while at the same time mitigating subsidence risks. CalGEM's local office has preliminarily indicated that the injection well pressure gradient should be reduced from the gradient that has been used for several decades. As part of our ongoing discussions, we and the City of Long Beach have provided CalGEM with technical information regarding how the historical injection well pressure gradient complies with CalGEM's requirements and to inform them of the absence of risk of leakage. If CalGEM were to ultimately disagree and determine to reduce the injection well pressure gradient, and we were unable to reverse that decision on appeal or other legal challenge, we expect any material reduction in injection well pressure gradient for our operations in the Wilmington Oil Field would result in a decrease in production and reserves from the field.

Collectively, the effect of these regulations is to potentially limit the number and location of our wells and the amount of oil and natural gas that we can produce from our wells compared to what we otherwise would be able to do.

Regulation of Health, Safety and Environmental Matters

Numerous federal, state, local and other laws and regulations that govern health and safety, the release or discharge of materials, land use or environmental protection may restrict the use of our properties and operations, increase our costs or lower demand for or restrict the use of our products and services. Applicable federal health, safety and environmental laws include the Occupational Safety and Health Act, Clean Air Act, Clean Water Act, Safe Drinking Water Act, Oil Pollution Act, Natural Gas Pipeline Safety Act, Pipeline Safety Improvement Act, Pipeline Safety, Regulatory Certainty, and Job Creation Act, Endangered Species Act, Migratory Bird Treaty Act, Comprehensive Environmental Response, Compensation, and Liability Act, Resource Conservation and Recovery Act and NEPA, among others. California imposes additional laws that are analogous to, and often more stringent than, such federal laws. These laws and regulations:

- establish air, soil and water quality standards for a given region, such as the San Joaquin Valley, conduct regional, community or field monitoring of air, soil or water quality, and require attainment plans to meet those regional standards, which may include significant mitigation measures or restrictions on development, economic activity and transportation in such region;
- require various permits, approvals and mitigation measures before drilling, workover, production, underground fluid injection or waste disposal commences, or before facilities are constructed or put into operation;
- require the installation of sophisticated safety and pollution control equipment, such as leak detection, monitoring and shutdown systems, and implementation of inspection, monitoring and repair programs to prevent or reduce releases or discharges of regulated materials to air, land, surface water or ground water;
- restrict the use, types or sources of water, energy, land surface, habitat or other natural resources, require conservation and reclamation measures, impose energy efficiency or renewable energy standards on us or users of our products and services, and restrict the use of oil, natural gas or certain petroleum–based products such as fuels and plastics;
- restrict the types, quantities and concentrations of regulated materials, including oil, natural gas, produced water or wastes, that can be released or discharged into the environment, or any other uses of those materials resulting from drilling, production, processing, power generation, transportation or storage activities;

- limit or prohibit operations on lands lying within coastal, wilderness, wetlands, groundwater recharge, endangered species habitat and other protected areas, and require the dedication of surface acreage for habitat conservation;
- establish standards for the management of solid and hazardous wastes or the closure, abandonment, cleanup or restoration of former operations, such as plugging and abandonment of wells and decommissioning of facilities;
- impose substantial liabilities for unauthorized releases or discharges of regulated materials into the environment with respect to our current or former properties and operations and other locations where such materials generated by us or our predecessors were released or discharged;
- require comprehensive environmental analyses, recordkeeping and reports with respect to operations affecting federal, state and private lands or leases;
- impose taxes or fees with respect to the foregoing matters;
- may expose us to litigation with government authorities, counterparties, special interest groups or others; and
- may restrict our rate of oil, NGLs, natural gas and electricity production.

Due to the risk of future drought conditions in California, water districts and the state government have implemented regulations and policies that may restrict groundwater extraction and water usage and increase the cost of water. Water management, including our ability to recycle, reuse and dispose of produced water and our access to water supplies from third-party sources, in each case at a reasonable cost, in a timely manner and in compliance with applicable laws, regulations and permits, is an essential component of our operations to produce crude oil, natural gas and NGLs economically and in commercial quantities. As such, any limitations or restrictions on wastewater disposal or water availability could have an adverse impact on our operations. We treat and reuse water that is co-produced with oil and natural gas for a substantial portion of our needs in activities such as pressure management, waterflooding, steamflooding and well drilling, completion and stimulation. We also provide reclaimed produced water to certain agricultural water districts. We also use supplied water from various local and regional sources, particularly for power plants and steam generation. We are a net fresh water supplier to the State. While our production to date has not been impacted by restrictions on access to third-party water sources, we cannot guarantee that there may not be restrictions in the future.

In 2014, at the request of the EPA, CalGEM commenced a detailed review of the multi-decade practice of permitting underground injection wells and associated aquifer exemptions under the SDWA. In 2015, the state set deadlines to obtain the EPA's confirmation of aquifer exemptions under the SDWA in certain formations in certain fields. Since the state and the EPA did not complete their review before the state's deadlines, the state announced that it will not rescind permits or enforce the deadlines with respect to many of the formations pending completion of the review but has applied the deadlines to others. Several industry groups and operators challenged CalGEM's implementation of its aquifer exemption regulations. In March 2017, the Kern County Superior Court issued an injunction barring the blanket enforcement of CalGEM's aquifer exemption regulations. The court found that CalGEM must find actual harm results from an injection well's operations and go through a hearing process before the agency can issue fines or shut down operations. During the review, the state has restricted injection in certain formations or wells in several fields, including some operated by us, requested that we change injection zones in certain fields, and held certain pending injection permits in abeyance. We are coordinating with the state to change injection zones in certain fields to facilitate disposal of produced water in deeper formations where feasible or to increase recycling of produced water in pressure maintenance or waterfloods in lieu of disposal. In September 2021, the EPA issued a letter to the California Natural Resources Agency and the State Water Resources Control Board regarding the state's compliance with the 2015 compliance plan relating to the state's process for approving aquifer exemptions under the SDWA. The letter requested that California take appropriate action by September 2022, or the EPA would consider taking additional action to impose limits on California's administration of the UIC program, withhold federal funds for the administration of the UIC program, and direct orders to oil and natural gas operators injecting into formations not authorized by the EPA, among other measures. The state responded in October 2021 with a proposed compliance plan and a follow-up letter in August 2022 providing a mid-year update, but, to date, the EPA has not yet responded.

With respect to major federal actions pursuant to NEPA, recent modifications may impose additional restrictions on oil and natural gas activities on federal lands. In October 2021, the Biden Administration announced three significant changes to a 2020 rule finalized under the Trump Administration. These changes included (i) authorizing agencies to consider the direct, indirect and cumulative effects of major federal actions including upstream and downstream impacts of fossil fuel projects; (ii) allowing agencies to determine the purpose and need of a project (thereby allowing consideration of less-harmful alternatives); and (iii) affording agencies greater flexibility in crafting their own NEPA procedures, consistent with Council of Environmental Quality (CEQ) regulations, so as to meet the agencies' and public's need. To that end, in April 2022, the CEQ issued a final rule in line with the proposed changes – "Phase I" of the Biden Administration's two-phased approach to modifying NEPA. "Phase 2" of the process includes the release of a new rule proposing broader changes to NEPA regulations.

Federal, state and local agencies may assert overlapping authority to regulate in these areas. In addition, certain of these laws and regulations may apply retroactively and may impose strict or joint and several liability on us for events or conditions over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

Regulation of Carbon Capture, Sequestration and Storage

On September 16, 2022, the Governor of California signed Senate Bill No. 905 into law, which contemplates the development of unitization, permitting and pipeline safety regulations over a multi-year period to facilitate the development of CCS projects in California, though the legislation does not provide for compulsory unitization. Protocols to support CCS are to be adopted by January 1, 2024 and a unified permit application is to be adopted by January 1, 2025. We believe our Carbon TerraVault projects, for which permits with the EPA have been filed, will continue to be developed on a timeline consistent with our initial expectations. These initial projects are not reliant on the unitization or permitting regulations being developed. In addition, our Carbon TerraVault projects are expected to either use emitters that are directly sited above these storage facilities or rely on pipelines for transporting CO_2 that will need to comply with yet to be developed CO_2 pipeline safety regulations from the federal PHMSA, which could take a number of years to effect. However, the terms of the final pipeline safety regulations may impair or prohibit those projects that rely on the transportation of CO_2. In addition, delays in developing the required pipeline safety regulations would delay projects requiring pipeline transportation of CO_2. The lack of compulsory unitization could also delay project timelines.

The unified permitting process contemplated by Senate Bill No. 905 will be optional for project applicants and is intended to simplify the permitting process for CCS projects. In the meantime, pursuant to this legislation we are permitted to proceed with our existing and future permit applications with the EPA. This law also contemplates the implementation of a new regulatory program incorporating standards that are not yet defined and that could affect the timing of future CCS projects in California.

Senate Bill No. 905 also prohibits CCS projects that utilize and permanently sequester CO_2 in connection with Enhanced Oil Recovery (EOR) projects. In light of this prohibition and the enhancement of energy credits under the Inflation Reduction Act of 2022 (the Act), we transitioned our CalCapture project to target CCS.

We currently do not have any oil and natural gas production or proved reserves associated with EOR projects that rely on CO_2 floods. As a result, we do not expect the limitations on EOR activities included in Senate Bill No. 905 to impact our existing oil and natural gas production or proved reserves.

President Biden signed the Act into law on August 16, 2022. Beginning in 2024, the Act’s methane emissions charge imposes a fee on excess methane emissions from certain oil and natural gas facilities, including some of our facilities, starting at $900 per metric ton of leaked methane in 2024 and rising to $1,200 in 2025, and $1,500 in 2026 and thereafter.

The Act also enhanced existing credits for emissions reduction and sequestration (45Q credit) by increasing the size of the credit to $85 per metric ton when captured from industrial and power generation facilities, and to $180 per metric ton when utilizing direct air capture facilities. The Act also extended the date for when qualifying facilities must begin construction by seven years, among other modifications. Further, a direct pay option for the 45Q credit (for a limited five-year period) was added and the Act provides an option to monetize the 45Q credit through a sale to another taxpayer. These additional energy-related tax incentives are effective for new projects beginning on January 1, 2023 and enhance the development of CCS projects in California.

Regulation of Climate Change and Greenhouse Gas (GHG) Emissions

A number of international, federal, state, regional and local efforts seek to prevent or mitigate the effects of climate change or to track, mitigate and reduce GHG emissions associated with energy use and industrial activity, including operations of the oil and natural gas production sector and those who use our products as a source of energy or feedstocks. President Biden has made climate change a focus of his administration, and he has issued several executive orders on the subject, which, among other things, recommitted the United States to the Paris Agreement in 2021, called for the reinstatement or issuance of methane emissions standards for new, modified and existing oil and natural gas facilities (rules pertaining to which have been proposed by the EPA) and called for an increased emphasis on climate-related risk across governmental agencies and economic sectors. Additionally, the EPA has adopted federal regulations to:

- require reporting of annual GHG emissions from oil and natural gas exploration and production, power plants and natural gas processing plants; gathering and boosting compression and pipeline facilities; and certain completions and workovers;
- incorporate measures to reduce GHG emissions in permits for certain facilities; and
- restrict GHG emissions from certain mobile sources.

California has adopted stringent laws and regulations to reduce GHG emissions. These state laws and regulations:

- established a “cap-and-trade” program for GHG emissions that sets a statewide maximum limit on covered GHG emissions, and this cap declines annually to reach 40% below 1990 levels by 2030, the year that the cap-and-trade program currently expires;
- require allowances or qualifying offsets for GHGs emitted from California operations and for the volume of natural gas, propane and liquid transportation fuels sold for use in California;
- established a low carbon fuel standard (LCFS) and associated tradable credits that require a progressively lower carbon intensity of the state’s fuel supply than baseline gasoline and diesel fuels, and provide a mechanism to generate LCFS credits through innovative crude oil production methods such as those employing solar or wind energy or carbon capture and sequestration;
- mandated that California derive 60% of its electricity for retail customers from renewable resources by 2030;
- established a policy to derive all of California’s retail electricity from renewable or “zero-carbon” resources by 2045, subject to required evaluation of the feasibility by state agencies;
- imposed state goals to double the energy efficiency of buildings by 2030 and to reduce emissions of methane and fluorocarbon gases by 40% and black carbon by 50% below 2013 levels by 2030; and
- mandated that all new single family and low–rise multifamily housing construction in California include rooftop solar systems or direct connection to a state–approved community solar system.

In addition, the current and former Governors of California and certain municipalities in California have announced their commitment to adhere to GHG reductions called for in the Paris Agreement through executive orders, pledges, resolutions and memoranda of understanding or other agreements with various other countries, U.S. states, Canadian provinces and municipalities. In furtherance of this commitment, in September 2022, the Governor of California signed Assembly Bill No. 1279 into law, which codifies a previously issued executive order by the Governor's Office requiring the state to achieve carbon neutrality by 2025. In addition, the Governor of California previously issued an executive order directing several agencies to take further actions with respect to reducing emissions of GHGs. The Governor has also directed state agencies to implement other measures to mitigate climate change and strengthen biodiversity, such as via the conservation of 30% of state lands and waters by 2030. For more information, see *Part I, Item 1A – Risk Factors, Risks Related to Regulation and Government Action, Recent and future actions by the State of California could reduce both the demand for and supply of oil and natural gas within the state and consequently have a material and adverse effect on our business, results of operations and financial condition*.

The EPA and the California Air Resources Board (CARB) have also expanded direct regulation of methane as a contributor to GHG emissions. In 2016, the EPA adopted regulations to require additional emission controls for methane, volatile organic compounds and certain other substances for new or modified oil and natural gas facilities. Although the EPA rescinded the methane-specific requirements for production and processing facilities in September 2020, the U.S. Congress subsequently approved, and President Biden signed into a law, a resolution to repeal the September 2020 revisions to the methane standards, effectively reinstating the prior standards. Additionally, in November 2021, the EPA issued a proposed rule that, if finalized, would establish new source and first-time existing source standards of performance for methane and volatile organic compound emissions for oil and natural gas facilities. In November 2022, the EPA issued a supplemental proposal which sets forth specific revisions strengthening the first nationwide emissions guidelines for states to limit methane from existing oil and natural gas facilities and revises requirements for fugitive emissions monitoring and repair as well as equipment leaks and the frequency of monitoring surveys, among other items. The proposal is expected to be finalized in 2023, though it will likely be challenged. Moreover, CARB has implemented more stringent regulations that require monitoring, leak detection, repair and reporting of methane emissions from both existing and new oil and natural gas production, pipeline gathering and boosting facilities and natural gas processing plants, as well as additional controls such as tank vapor recovery to capture methane emissions.

Regulation of Transportation, Marketing and Sale of Our Products

Our sales prices of oil, NGLs and natural gas in the U.S. are set by the market and are not presently regulated. In 2015, the U.S. federal government lifted restrictions on the export of domestically produced oil that allows for the sale of U.S. oil production, including ours, in additional markets.

Federal and state laws regulate transportation rates for, and marketing and sale of, petroleum products and electricity with respect to certain of our operations and those of certain of our customers, suppliers and counterparties. Such regulations also govern:

- interstate and intrastate pipeline transportation rates for oil, natural gas and NGLs in regulated pipeline systems;
- prevention of market manipulation in the oil, natural gas, NGL and power markets;
- market transparency rules with respect to natural gas and power markets;
- the physical and futures energy commodities market, including financial derivative and hedging activity; and
- prevention of discrimination in natural gas gathering operations in favor of producers or sources of supply.

The federal and state agencies overseeing these regulations have substantial rate-setting and enforcement authority, and violation of the foregoing regulations could expose us to litigation with government authorities, counterparties, special interest groups and others.

International treaties and regulations also affect the marketing or sale of our products. For example, on January 1, 2020, the International Maritime Organization reduced the maximum sulfur content in marine fuels from 3.5% to 0.5% by weight under the International Convention for the Prevention of Pollution from Ships. Under this IMO 2020 rule, ships must either switch to low-sulfur fuels or install scrubbing facilities for emission controls, which may affect the price of and demand for varying grades of crude oil, both internationally and in California.

In addition, mandates or subsidies have been adopted or proposed by the state and certain local governments to require or promote renewable energy or electrification of transportation, appliances and equipment, or prohibit or restrict the use of petroleum products, by our customers or the public. For example, in January 2020, the California Public Utilities Commission (CPUC) commenced a rulemaking to develop a long-term natural gas planning strategy to ensure safe and reliable gas systems at just and reasonable rates during what it describes as a 25-year transition from natural gas-fueled technologies to meet the state's GHG goals. In addition, several municipalities in California enacted ordinances in 2019 that restrict the installation of natural gas appliances and infrastructure in new residential or commercial construction, which could affect the retail natural gas market of our utility customers and the demand and prices we receive for the natural gas we produce. Several of these ordinances face legal challenges.

Available Information

We make available, free of charge on our website www.crc.com, our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, Definitive Proxy Statements and amendments to those reports filed or furnished, if any, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Unless otherwise provided herein, information contained on our website is not part of this report. The SEC maintains an internet site, http://www.sec.gov, that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

ITEM 1A RISK FACTORS

Described below are certain risks and uncertainties that could adversely affect our business, financial condition, results of operations or cash flow. These risks are not the only risks we face. Our business could also be affected materially and adversely by other risks and uncertainties that are not currently known to us or that we currently deem to be insignificant.

Summary:

Risks Related to Our Business

- Prices for our products can fluctuate widely and an extended period of low prices could materially and adversely affect our financial condition, results of operations, cash flow and ability to invest in our assets.
- Our producing properties are located exclusively in California, making us vulnerable to risks associated with having operations concentrated in this geographic area.
- We may not be able to successfully separate our carbon management business from our E&P business, or we may decide not to effect such separation.
- Our ability to achieve our 2045 Full-Scope Net Zero target and other goals related to carbon management activities, is subject to risks and uncertainties.
- Our ability to grow our Carbon TerraVault business and develop large scale CCS projects is subject to numerous risks and uncertainties. If we are unable to successfully execute our CCS strategy, it could have an adverse effect on our business, results of operations and financial condition.
- The economics of CCS projects depend on financial and tax incentives that may not currently be sufficient for our CCS projects to be economical or could be changed or terminated.
- Our Carbon TerraVault JV with Brookfield is subject to inherent uncertainties, which could force us to delay or cancel CCS projects or seek alternative sources of capital to fund our CCS projects and thereby adversely affect our ability to implement our carbon management strategy.
- Drilling for and producing oil and natural gas carry significant operational and financial risks and uncertainty. We may not drill wells at the times we scheduled, or at all. Wells we do drill may not yield production in economic quantities or generate the expected payback.
- Our business involves substantial capital investments. We may be unable to fund our capital program, or reach satisfactory terms for other future capital requirements which could lead to a decline in our oil and natural gas reserves or production. Our capital investment program is also susceptible to risks that could materially affect its implementation.
- We have been negatively impacted by inflation.
- We are subject to economic downturns and the effects of public health events, such as the COVID-19 pandemic, which may materially and adversely affect the demand and the market price for our products.
- The conflict in Ukraine and related price volatility and geopolitical instability could negatively impact our business.
- From time to time we may engage in step-out drilling, or drilling in new or emerging plays. Our drilling results are uncertain, and the value of our undeveloped acreage may decline if drilling is unsuccessful.
- Many of our current and potential competitors have or may potentially have greater resources than we have and we may not be able to successfully compete in acquiring, exploring and developing new properties.
- Our hedging activities limit our ability to realize the full benefits of increases in commodity prices.
- Our level of hedging activities may be impacted by financial regulations that could increase our costs of hedging and/or limit the number of hedging counterparties available to us.
- Estimates of proved reserves and related future net cash flows are not precise. The actual quantities of our proved reserves and future net cash flows may prove to be lower than estimated.

Risks Related to Regulation and Government Action

- We may not be able to timely obtain drilling permits as a result of recent and future actions by the State of California.
- Recent and future actions by the State of California could reduce both the demand for and supply of oil and natural gas within the state and consequently have a material and adverse effect on our business, results of operations and financial condition.
- Our business is highly regulated and government authorities can delay or deny permits and approvals or change requirements governing our operations, which could increase costs, restrict operations and change or delay the implementation of our business plans.
- Our Carbon TerraVault business and our CCS projects are subject to extensive government regulation that, among other things, requires us to obtain and maintain permits for the injection and sequestration of CO_2. Many of these regulations are still being developed. Failure to comply with these requirements and obtain the necessary permits, or the development of government regulations that are unfavorable to our CCS projects, could have an adverse effect on our business, results of operations and financial condition.
- Recent changes in California law may result in delays to our carbon capture, sequestration and storage projects.
- Concerns about climate change and other air quality issues may prompt governmental action that could materially affect our operations or results.
- The Inflation Reduction Act could accelerate the transition to a low-carbon economy and could impose new costs on our operations.
- Adverse tax law changes may affect our operations.

Risks Related to our Indebtedness

- We may not be able to amend or refinance our existing debt to create more operating and financial flexibility and to enhance shareholder returns.
- Our existing and future indebtedness may adversely affect our business and limit our financial flexibility.
- We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy the obligations under our indebtedness, which may not be successful.
- The lenders under our Revolving Credit Facility could limit our ability to borrow and restrict our ability to use or access to capital.
- Restrictive covenants in our Revolving Credit Facility and the indenture governing our Senior Notes may limit our financial and operating flexibility.
- Variable rate indebtedness under our Revolving Credit Facility subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Risks Related to Our Common Stock

- Our ability to pay dividends and repurchase shares of our common stock is subject to certain risks.
- The trading price of our common stock may decline, and you may not be able to resell shares of our common stock at prices equal to or greater than the price you paid or at all.
- Future issuances of our common stock could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.
- There is an increased potential for short sales of our common stock due to the sales of shares issued upon exercise of warrants, which could materially affect the market price of the stock.
- The ownership position of certain of our stockholders limits other stockholders' ability to influence corporate matters and could affect the price of our common stock.
- Sales of shares of our common stock by our executive officers could negatively impact the market price for our common stock.

General Risk Factors

- Increasing attention to ESG matters may adversely impact our business.
- Acquisition and disposition activities involve substantial risks.
- We may incur substantial losses and be subject to substantial liability claims as a result of pollution, environmental conditions or catastrophic events. We may not be insured for, or our insurance may be inadequate to protect us against, these risks.
- Cybersecurity attacks, systems failures and other disruptions could adversely affect us.

Risks Related to Our Business

Prices for our products can fluctuate widely and an extended period of low prices could materially and adversely affect our financial condition, results of operations, cash flow and ability to invest in our assets.

Our financial condition, results of operations, cash flow and ability to invest in our assets are highly dependent on oil, natural gas and NGL prices. A sustained period of low prices for oil, natural gas and NGLs would reduce our cash flows from operations and could reduce our borrowing capacity or cause a default under our financing agreements.

Prices for oil, natural gas and NGL may fluctuate widely in response to relatively minor changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, such as:

- changes in domestic and global supply and demand;
- domestic and global inventory levels;
- political and economic conditions, including international disputes such as the conflict between Ukraine and Russia;
- pandemics, epidemics, outbreaks or other public health events, such as the COVID-19 pandemic;
- the actions of OPEC and other significant producers and governments;
- changes or disruptions in actual or anticipated production, refining and processing;
- worldwide drilling and exploration activities;
- government energy policies and regulation, including with respect to climate change;
- the effects of conservation;
- weather conditions and other seasonal impacts;
- speculative trading in derivative contracts;
- currency exchange rates;
- technological advances;
- transportation and storage capacity, bottlenecks and costs in producing areas;
- the price, availability and acceptance of alternative energy sources;
- regional market conditions; and
- other matters affecting the supply and demand dynamics for these products.

Lower prices could have adverse effects on our business, financial condition, results of operations and cash flow, including:

- reducing our proved oil and natural gas reserves over time;
- limiting our ability to grow or maintain future production;
- causing a reduction in our borrowing base under our Revolving Credit Facility, which could affect our liquidity;
- reducing our cash flow and ability to make interest payments or maintain compliance with financial covenants in the agreements governing our indebtedness, which could trigger mandatory loan repayments and default and foreclosure by our lenders and bondholders against our assets;

- affecting our ability to attract counterparties and enter into commercial transactions, including hedging, surety or insurance transactions; and
- limiting our access to funds through the capital markets and the price we could obtain for asset sales or other monetization transactions.

Our hedging program does not provide downside protection for all of our production. As a result, our hedges do not fully protect us from commodity price declines, and we may be unable to enter into acceptable additional hedges in the future.

Our producing properties are located exclusively in California, making us vulnerable to risks associated with having operations concentrated in this geographic area.

Our operations are concentrated in California. Because of this geographic concentration, the success and profitability of our operations may be disproportionately exposed to the effect of regional conditions. These changes in state or regional laws and regulations affecting our operations, local price fluctuations and other regional supply and demand factors, including gathering, pipeline, transportation and storage capacity constraints, limited potential customers, infrastructure capacity and availability of rigs, equipment, oil field services, supplies and labor. Our operations are also exposed to natural disasters and related events common to California, such as wildfires, mudslides, high winds, earthquakes and extreme weather events, and the potential increase to the frequency of drought and flooding. Further, our operations may be exposed to power outages, mechanical failures, industrial accidents or labor difficulties. Any one of these events has the potential to cause producing wells to be shut in, delay operations and growth plans, decrease cash flows, increase operating and capital costs, prevent development of lease inventory before expiration and limit access to markets for our products.

We may not be able to successfully separate or finance our carbon management business from our E&P business, or we may decide not to effect such separation.

On February 24, 2023, we announced that we had adjusted our corporate operating structure, including setting up a board of directors at Carbon TerraVault, to facilitate the separate operation of our E&P and carbon management businesses. We also intend to pursue financing options for our carbon management business that are separate from the rest of our business. Our carbon management business faces operational, technological and regulatory risks that could be considerable due to early stage nature of these projects and the sector generally, which may make it more difficult to independently finance and there are no assurances that it will be a viable standalone business in the near term or at all. Further, there can be no assurances that we will be able to successfully separate our E&P and carbon management businesses. We also may decide not to pursue such separation if we do not believe it would maximize shareholder value.

Our ability to achieve our 2045 Full-Scope Net Zero target and other goals related to our carbon management activities, is subject to risks and uncertainties.

We have adopted a number of targets and objectives related to sustainability matters, including our 2045 Full-Scope Net Zero target and our energy transition strategy. Our efforts to research, establish, accomplish, and accurately report on these targets and objectives expose us to numerous operational, reputational, financial, legal, and other risks. Our ability to achieve any stated target or objective is not guaranteed and is subject to numerous factors and conditions, some of which are outside of our control. In particular, our 2045 Full-Scope Net Zero goal includes Scope 1, 2 and 3 emissions and estimation and management of Scope 3 emissions is subject to some degree of uncertainty. We cannot guarantee that we have been able to completely quantify the full scope of our emissions and account for mitigating all such emissions in our Full-Scope Net Zero goal.

Our ability to achieve our 2045 Full-Scope Net Zero goal relies heavily on our ability to develop our Carbon TerraVault business and related CCS projects, which is subject to uncertainties and risks. See *Risks Related to our Business – The economics of CCS projects depend on financial and tax incentives that may not currently be sufficient for our CCS projects to be economical or could be changed or terminated, Risks Related to our Business – Our Carbon TerraVault JV with Brookfield is subject to inherent uncertainties, which could force us to delay or cancel CCS projects or seek alternative sources of capital to fund our CCS projects and thereby adversely affect our ability to implement our carbon management strategy*. In addition, the commercial and regulatory environment related to emissions reductions and reporting is evolving and uncertain, and changes in GHG emission accounting methodologies or new developments related to climate science could impact our ability to claim emissions reductions related to our sequestration activities and timely achieve our 2045 Full-Scope Net Zero goal or at all. If we are not able to successfully develop Carbon TerraVault and its CCS projects and claim related emissions reductions, or we are successful in separating our carbon management business, our ability to achieve our 2045 Full-Scope Net Zero goal would be materially and adversely affected.

Our business may face increased scrutiny from investors and other stakeholders related to our sustainability activities, including the goals, targets, and objectives that we announce, and our methodologies and timelines for pursuing them. If our sustainability practices do not meet investor or other stakeholder expectations and standards, which continue to evolve, our reputation, our ability to attract or retain employees, and our attractiveness as an investment or business partner could be negatively affected. Similarly, our failure or perceived failure to pursue or fulfill our sustainability-focused goals, targets, and objectives, to comply with ethical, environmental, or other standards, regulations, or expectations, or to satisfy various reporting standards with respect to these matters, within the timelines we announce, or at all, could adversely affect our business or reputation, as well as expose us to government enforcement actions and private litigation.

Our ability to grow our Carbon TerraVault business and develop large scale CCS projects is subject to numerous risks and uncertainties. If we are unable to successfully execute our CCS strategy, it could have an adverse effect on our business, results of operations and financial condition.

We have announced a strategy to pursue the development of a carbon management business in California. To our knowledge, there are no existing large scale CCS projects in California similar to those that we are seeking to have developed. These projects face operational, technological and regulatory risks that could be considerable due to early stage nature of these projects and the sector generally. Our ability to successfully develop these projects depends on a number of factors that we are not able to fully control, including the following:

- The development of large scale CCS projects is an emerging sector and there are no meaningful precedents to gauge the likely range of economic terms upon which these projects may be feasibly developed. In addition, any of the operational, regulatory or financial risks could cause actual results to differ materially from expected payback or cause a project to become uneconomic or less profitable than forecast.
- The development of CCS projects will require us, our joint venture partner, and third-party emitters to make significant capital investments in the relevant technology and infrastructure and we may not have sufficient capital resources to fund such investments. Such projects may also depend on third party financing and such financing may not be available on reasonable terms or at all. In some cases, these projects will involve the production and sale of hydrogen, ammonia or other products and markets for some of these products are still being developed.

- The development of a CCS project will require us to enter into long term binding agreements with large carbon emitters and other third parties and we may not be able to do so on agreeable terms or at all. Such agreements are complex and may involve allocation of not only fees but also various credits, incentives and environmental attributes associated with the storage of CO_2. Not all emission sources produce sufficiently large quantities of pure or relatively pure streams of CO_2, or have installed equipment to capture such CO_2, so as to be useable in one or more of our CCS projects. As a result, we cannot assure whether we will be able to procure sufficient quantities of CO_2 on terms that are acceptable to us, and the failure to do so may have a material impact on our ability to execute our CCS strategy.
- The development and operation of cost-effective, commercial-scale hydrogen and ammonia production facilities and associated sequestration facilities is highly complex. There can be no assurances that our partners will be able to successfully develop these production facilities, or that we will be able to develop the related sequestration facilities, in a timely manner or at all. In addition, there can be no assurances that these facilities can be maintained and operated over the longer term.
- Certain of our anticipated CCS project sites rely on pore space that we do not own and we may need to enter into agreements with landowners to allow us to inject CO_2.
- Complex recordkeeping and GHG emissions/sequestration accounting may be required in connection with one or more of our projects, which may increase the costs of such operations. Different methodologies may be required for various regulatory and non-regulatory accounts regarding GHG emissions/sequestration at one or more of our projects, including but not limited to compliance with the EPA’s Mandatory Greenhouse Gas Reporting Program.
- Carbon capture may be viewed as a pathway to the continued use of fossil fuels and there may be organized opposition to CCS projects from environmental groups, local residents and legislators.
- We may need to transport CO_2 in pipelines if a CCS project relies on storage space that is not co-located with the production facilities. Our ability to transport CO_2 is subject to regulatory uncertainty, see *Risks Related to Regulation and Government Action – Senate Bill 905 may result in delays to our CCS projects* described below.
- Other regulatory uncertainties, see *Risks Related to Regulation and Government Action – Our Carbon TerraVault business and our CCS projects are subject to extensive government regulation that, among other things, requires us to obtain permits for the injection of CO_2. Many of these regulations are still being developed. Failure to comply with these requirements and obtain the necessary permits, or the development of government regulation that is unfavorable to our CCS projects, could have a material adverse effect on our business, results of operations and financial condition* described below.

There can be no assurances that we will successfully develop our CCS projects, including Carbon TerraVault and CalCapture, and such failure could have an adverse effect on our business. Our carbon management business is currently in an early stage of development, and we do not expect the failure of a single CCS project to create an impact on our overall financial condition or operations. However, as the scale of our CCS projects grows, so will their impact on our overall financial condition and operations. Moreover, our failure to successfully develop our CCS projects would adversely affect our ability to claim emissions reductions related to our sequestration activities and our ability to meet our carbon management goals, which in turn could have an adverse effect on our business and reputation.

The economics of CCS projects depend on financial and tax incentives that may not currently be sufficient for our CCS projects to be economical or could be changed or terminated.

Congress has incentivized the development of carbon capture projects through the establishment of tax credits for the capture and sequestration of CO_2, the production of clean hydrogen and the production of other clean fuels. The successful development of our CCS projects is dependent upon our ability to directly or indirectly benefit from these tax credits. The amount of tax credits from which we may directly or indirectly benefit on our CCS projects is dependent upon satisfaction of certain requirements, which we cannot assure you that we (or our partners) will satisfy. One of those requirements is that a minimum volume of CO_2 is captured by the applicable carbon capture equipment during each taxable year. If we or our counterparties are not able to capture the minimum volumes (which could be for a variety of reasons), then the tax credit will not be available. Additional financial incentives may also be required for our CCS projects to be economical. In particular, we anticipate that CCS projects associated with carbon emission reductions for transportation fuels will generate LCFS credits and that these additional credits will improve the economics of CCS projects. If the existing legal requirements for incentives such as the tax credits available for the capture and sequestration of CO_2 and the production of clean hydrogen or LCFS are subsequently amended in a manner that such incentives no longer apply or are restricted in application, directly or indirectly, to our projects, we may not be able to successfully achieve an economic return from our CCS business or, alternatively, the construction or operation of applicable projects may be substantially delayed such that one or more projects is unprofitable or otherwise infeasible.

The ability to monetize the tax credits for CO_2 capture and sequestration is not certain. Either the new owners of the carbon capture facilities or the sequester must either have the ability to use the tax credit for itself, utilize direct pay (which is limited to the first five years), procure tax equity financing or transfer the credits to another tax-payer. The ability to utilize direct pay and the tax equity financing and credit transfers markets for tax credits provided under the IRA are still being analyzed and subject to further guidance from the IRS, and therefore many uncertainties and complexities with respect to the ability to monetize these credits exist.

The tax credit for the capture and sequestration of CO_2 requires that the captured CO_2 be stored in secure geological storage for long periods of time. If we are not able to satisfy this requirement for the duration of time required, there is the risk of recapture of tax credits or LCFS credits from us (or our partners) by the government, as well as a risk of indemnification obligations to our partners, claims from landowners and potential for fines and penalties for violations of environmental requirements. Accidental releases of CO_2 could also adversely impact our ability to meet our 2045 Full-Scope Net Zero goal.

There can be no assurances that we (or our partners) will successfully comply with the requirements for the available tax credits or LCFS, and such failure could have an adverse effect on our liquidity, financial condition and results of operations.

Our Carbon TerraVault JV with Brookfield is subject to inherent uncertainties, which could force us to delay or cancel CCS projects or seek alternative sources of capital to fund our CCS projects and thereby adversely affect our ability to implement our carbon management strategy.

In August 2022, we entered into the Carbon TerraVault JV with Brookfield to pursue the development of a carbon management business in California. The management and financing of the joint venture are subject to inherent uncertainties. These uncertainties could potentially force us to delay or cancel CCS projects or to seek alternative sources of capital to fund our CCS projects, any of which could adversely affect our ability to achieve our 2045 Full-Scope Net Zero target and other goals related to our carbon management activities.

Brookfield has committed an initial $500 million to invest in CCS projects that are jointly approved through Carbon TerraVault JV. At the time the Carbon TerraVault JV was formed, Brookfield committed to make an initial investment of $137 million payable in three equal installments. The first $46 million installment was contributed to the joint venture in August 2022, and the next two installments are due upon completion of certain pre-agreed milestones related to the permitting process with the EPA and final investment decision. Future storage projects for Brookfield's initial commitment are subject to approval of the joint venture, including Brookfield. There can be no assurances that any of these funding milestones will be achieved so that Brookfield will fund the rest of its commitment.

Furthermore, even though we own a 51% interest in the Carbon TerraVault JV, we share decision making power with Brookfield on matters that most significantly impact the economic performance of the joint venture. Any failure to reach a decision with Brookfield could potentially prevent or delay our pursuit of CCS projects or cause such projects to be cancelled. Moreover, if Brookfield does not approve a proposed CCS project that we want to pursue, we will have to seek alternative sources of capital to fund the project and there can be no assurances that such sources of capital will be available.

Drilling for and producing oil and natural gas carry significant operational and financial risks and uncertainty. We may not drill wells at the times we scheduled, or at all. Wells we do drill may not yield production in economic quantities or generate the expected payback.

The exploration and development of oil and natural gas properties depend in part on our analysis of geophysical, geologic, engineering, production and other technical data and processes, including the interpretation of 3D seismic data. This analysis is often inconclusive or subject to varying interpretations. We also bear the risks of equipment failures, accidents, environmental hazards, unusual geological formations or unexpected pressure or irregularities within formations, adverse weather conditions, permitting or construction delays, title disputes, surface access disputes, disappointing drilling results or reservoir performance (including lack of production response to workovers or improved and enhanced recovery efforts) and other associated risks.

Our decisions and ultimate profitability are also affected by commodity prices, the availability of capital, regulatory approvals, available transportation and storage capacity, the political environment and other factors. Our cost of drilling, completing, stimulating, equipping, operating, inspecting, maintaining and abandoning wells is also often uncertain.

Any of the forgoing operational or financial risks could cause actual results to differ materially from the expected payback or cause a well or project to become uneconomic or less profitable than forecast.

We have specifically identified locations for drilling over the next several years, which represent a significant part of our long-term growth strategy. Our actual drilling activities may materially differ from those presently identified. If future drilling results in these projects do not establish sufficient production and reserves to achieve an economic return, we may curtail drilling or development of these projects. We make assumptions about the consistency and accuracy of data when we identify these locations that may prove inaccurate. We cannot guarantee that our identified drilling locations will ever be drilled or if we will be able to produce crude oil or natural gas from these drilling locations. In addition, some of our leases could expire if we do not establish production in the leased acreage. The combined net acreage covered by leases expiring in the next three years represented 8% of our total net undeveloped acreage at December 31, 2022.

Our business involves substantial capital investments, which may include acquisitions, partnerships or joint venture arrangements with other oil and natural gas exploration and production companies or financial investors. We may be unable to fund our capital program, or reach satisfactory terms for other future capital requirements, which could lead to a decline in our oil and natural gas reserves or production. Our capital investment program is also susceptible to risks that could materially affect its implementation.

Our exploration, development and acquisition activities can involve substantial capital investments. We intend to fund our 2023 capital program using cash flow from operations. Accordingly, a reduction in projected operating cash flow could cause us to reduce our future capital investments. In general, the ability to execute our capital plan depends on a number of factors, including:

- the amount of oil, natural gas and NGLs we are able to produce;
- commodity prices;
- regulatory and third-party approvals;
- our ability to timely drill, complete and stimulate wells;
- our ability to secure equipment, services and personnel; and
- our liquidity and ability fund capital expenditures.

Access to future capital may be limited by our lenders, capital markets constraints, activist funds or investors, or poor stock price performance. Because of these and other potential variables, we may be unable to deploy capital in the manner planned, which may negatively impact our production levels and development activities and limit our ability to make acquisitions or enter into partnerships and farmout arrangements.

Unless we make sufficient capital investments and conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our ability to make the necessary long-term capital investments or acquisitions needed to maintain or expand our reserves may be impaired to the extent we have insufficient cash flow from operations or liquidity to fund those activities. Over the long term, a continuing decline in our production and reserves would reduce our liquidity and ability to satisfy our debt obligations by reducing our cash flow from operations and the value of our assets.

We have been negatively impacted by inflation.

Increases in inflation have had an adverse effect on us. Current and future inflationary effects may be driven by, among other things, supply chain disruptions and governmental stimulus or fiscal policies, and geopolitical instability. In 2022, we experienced high single digit inflation for certain materials and services we procure from vendors including OCTG, fluid hauling, drilling equipment and mechanical and electrical labor services, among other items. We have taken measures to limit the effects of the inflationary market by entering into contracts for materials and services with terms of one to three years. Additionally, we continually look at productivity and performance improvements from our vendors in order to mitigate these price increases and also to reduce volumes consumed. However, there can be no assurances that such measures will be effective and we anticipate modest price increases for materials and services in the future. Continuing increases in inflation could further increase our costs of labor and other costs related to our business, which could have an adverse impact on our business, financial position, results of operations and cashflows. Inflation has also resulted in higher interest rates in the United States, which could increase the cost of our future financing efforts.

We are subject to economic downturns and the effects of public health events, such as the COVID-19 pandemic, which may materially and adversely affect the demand and the market price for our products.

The COVID-19 pandemic has adversely affected the global economy, and has resulted in, among other things, travel restrictions, business closures and the institution of quarantining and other mandated and self-imposed restrictions on movement. The severity, magnitude and duration of COVID-19 or another pandemic, the extent of actions that have been or may be taken to contain or treat their impact, and the impacts on the economy generally and oil prices in particular, are uncertain, rapidly changing and hard to predict. This uncertainty could force us to reduce costs, including by decreasing operating expenses and lowering capital expenditures, and such actions could negatively affect future production and our reserves. We may experience labor shortages if our employees are unwilling or unable to come to work because of illness, quarantines, government actions or other restrictions in connection with the pandemic. If our suppliers cannot deliver the materials, supplies and services we need, we may need to suspend operations. In addition, we are exposed to changes in commodity prices which have been and will likely remain volatile. We cannot predict the duration and extent of the pandemic's adverse impact on our operating results.

Additionally, to the extent the COVID-19 pandemic or any resulting worsening of the global business and economic environment adversely affects our business and financial results, it may also have the effect of heightening or exacerbating many of the other risks described in the *Risk Factors* herein.

The conflict in Ukraine and related price volatility and geopolitical instability could negatively impact our business.

In late February 2022, Russia launched significant military action against Ukraine. The conflict has caused, and could intensify, volatility in the prices of natural gas, oil and NGLs, and the extent and duration of the military action, sanctions and resulting market disruptions have been significant and could continue to have a substantial impact on the global economy and our business for an unknown period of time.

Further, in the fall of 2022, OPEC+ announced a 2 million barrel per day reduction in production quotas. This action was taken largely in response to the U.S. decision to continue releasing crude from its Strategic Petroleum Reserve. While actual OPEC+ production capabilities are difficult to discern, any return to previous targeted production levels could cause commodity prices to decline which would reduce the revenues we receive for our oil and natural gas production.

Materialization of either of the events described above may also magnify the impact of the other risks described in this "*Risk Factors*" section.

From time to time we may engage in step-out drilling or drilling in new or emerging plays. Our drilling results are uncertain, and the value of our undeveloped acreage may decline if drilling is unsuccessful.

The risk profile for step-out drilling or drilling in new or emerging plays is higher than for other locations because we have less geologic and production data and drilling history, in particular for drilling in unconventional reservoirs, which are in unproven geologic plays. Our ability to profitably drill and develop our identified drilling locations depends on a number of variables, including crude oil and natural gas prices, capital availability, costs, drilling results, regulatory approvals, available transportation capacity and other factors. We may not find commercial amounts of oil or natural gas or the costs of drilling, completing, stimulating and operating wells in these locations may be higher than initially expected. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling or development of these projects. In either case, the value of our undeveloped acreage may decline and could be impaired.

Many of our current and potential competitors have or may potentially have greater resources than we have and we may not be able to successfully compete in acquiring, exploring and developing new properties.

We face competition in every aspect of our business, including, but not limited to, acquiring reserves and leases, obtaining goods and services and hiring and retaining employees needed to operate and manage our business and marketing natural gas, NGLs or oil. Competitors include multinational oil companies, independent production companies and individual producers and operators. In California, our competitors are few and large, which may limit available acquisition opportunities. Many of our competitors have greater financial and other resources than we do. As a result, these competitors may be able to address such competitive factors more effectively than we can or withstand industry downturns more easily than we can.

Our hedging activities limit our ability to realize the full benefits of increases in commodity prices.

We enter into hedges to mitigate our economic exposure to commodity price volatility and ensure our financial strength and liquidity by protecting our cash flows. Our Revolving Credit Facility also includes a covenant that would require us to enter into a certain level of hedges if a financial metric related to our indebtedness is no longer satisfied. In addition, we have previously entered into incremental hedges above these requirements for certain time periods. These hedges expose us to the risk of financial losses depending on commodity price movements and may prevent us from realizing the full benefits of price increases. Our ability to realize the benefits of our hedges also depends in part upon the counterparties to these contracts honoring their financial obligations. If any of our counterparties are unable to perform their obligations in the future, we could be exposed to increased cash flow volatility that could affect our liquidity.

Our level of hedging activities may be impacted by financial regulations that could increase our costs of hedging and/or limit the number of hedging counterparties available to us.

U.S. financial regulations can impact both our level of hedging activity as well as the potential cost of entering into hedges. In particular, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), enacted in 2010, established federal oversight and regulation of the over-the-counter (OTC) derivatives market and entities, like us, that participate in that market. Among other things, the Dodd-Frank Act required the U.S. Commodity Futures Trading Commission to promulgate a range of rules and regulations applicable to OTC derivatives transactions. These regulations can affect both the size of positions that we may enter and the ability or willingness of counterparties to trade opposite us.

In addition, U.S. regulators adopted a final rule in November 2019 implementing a new approach for calculating the exposure amount of derivative contracts under the applicable agencies' regulatory capital rules, referred to as the standardized approach for counterparty credit risk (SA-CCR). Certain financial institutions were required to comply with the new SA-CCR rules beginning on January 1, 2022. The new rules could significantly increase the capital requirements for some of our hedge counterparties in the OTC derivatives market. These increased capital requirements could result in significant additional costs being passed through to end users like us or reduce the number of participants or products available to us in the OTC derivatives market.

The European Union and other non-U.S. jurisdictions may implement regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions or counterparties with other businesses that subject them to regulation in foreign jurisdictions, we may become subject to or otherwise impacted by such regulations, which could also adversely affect our hedging opportunities.

Estimates of proved reserves and related future net cash flows are not precise. The actual quantities of our proved reserves and future net cash flows may prove to be lower than estimated.

Many uncertainties exist in estimating quantities of proved reserves and related future net cash flows. Our estimates are based on various assumptions that require significant judgment in the evaluation of available information. Our assumptions may ultimately prove to be inaccurate. Additionally, reservoir data may change over time as more information becomes available from development and appraisal activities.

Our ability to add reserves, other than through acquisitions, depends on the success of improved recovery, extension and discovery projects, each of which depends on reservoir characteristics, technology improvements and oil and natural gas prices, as well as capital and operating costs. Many of these factors are outside management's control and will affect whether the historical sources of proved reserves additions continue to provide reserves at similar levels.

Generally, lower prices adversely affect the quantity of our reserves as those reserves expected to be produced in later years, which tend to be costlier on a per unit basis, become uneconomic. In addition, a portion of our proved undeveloped reserves may no longer meet the economic producibility criteria under the applicable rules or may be removed due to a lower amount of capital available to develop these projects within the SEC-mandated five-year limit.

In addition, our reserves information represents estimates prepared by internal engineers. Although 85% of our estimated proved reserve volumes as of December 31, 2022 were audited by our independent petroleum engineers, Ryder Scott and NSAI, we cannot guarantee that the estimates are accurate.

Reserves estimation is a partially subjective process of estimating accumulations of oil and natural gas. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows from those reserves depend upon a number of variables and assumptions. Changes in these variables and assumptions could require us to make significant negative reserves revisions, which could affect our liquidity by reducing the borrowing base under our Revolving Credit Facility. In addition, factors such as the availability of capital, geology, government regulations and permits, the effectiveness of development plans and other factors could affect the source or quantity of future reserves additions.

Risks Related to Regulation and Government Action

We may face material delays related to our ability to timely obtain permits necessary for our operations, or be unable to secure such permits on favorable terms or at all as a result of numerous California political, regulatory, and legal developments.

We must obtain various governmental permits to conduct exploration and production activities, as well as other aspects of our operations. Obtaining the necessary governmental permits is often a complex and time-consuming process involving numerous federal, state and local agencies. The duration and success of each permitting effort is contingent upon many variables not within our control. In the context of obtaining permits or approvals, the Company will need to comply with known standards, existing laws (such as CEQA), and regulations that may entail greater or lesser costs and delays depending on the nature of the activity to be permitted and the interpretation of the laws and regulations implemented by the permitting authority.

From time to time we have experienced significant delays with respect to obtaining drilling permits for our operations. A variety of factors outside of our control can lead to such delays. CalGEM has not issued any permits for new production wells to any operators since December 2022.

Recently, we have experienced delays obtaining permits as a result of litigation related to the Kern County EIR. On January 26, 2023, an appellate court issued a preliminary order reinstating a suspension of Kern County's ability to rely on an existing EIR to meet the County's obligations under CEQA in connection with oil and gas permitting. The original suspension was put in place in October 2021 in response to a lawsuit challenging the adequacy of that EIR for CEQA purposes. The county subsequently issued a supplemental EIR and took other steps to address the issues raised by the original lawsuit and in November 2022 a trial court approved the sufficiency of the supplemental EIR and lifted the suspension on Kern County's reliance on the EIR. On January 26, 2023, the Appellate Court issued a preliminary order on the petition reinstating a suspension of Kern County's ability to rely on the existing SREIR to meet CEQA requirements pending the outcome of a final order determining whether oil and natural gas permitting shall remain suspended for the duration of the appeals process. That order is still pending. While we can and intend to address CEQA compliance for our oil and natural gas permitting process through alternative pathways, this would be a lengthy process and we cannot predict whether we would be able to timely obtain permits using this alternative. As a result of these issues and current lack of permits with respect to our Kern County properties, we do not currently plan to drill and complete any additional wells within Kern County until permitting is resumed in Kern County, which may be later in the 2024 calendar year. However, there is no certainty that we will obtain permits on that timeline or at all, which may further adversely affect our future development plans, proved undeveloped reserves, business, operations, cash flows, financial position, and results of operation. Approximately 71% of our proved undeveloped reserves or 9% of our total proved reserves relate to wells to be drilled in Kern County beginning in 2024 for which we would need to obtain permits.

We have also experienced delays obtaining drilling permits from CalGEM since the passage of Senate Bill No. 1137, which established 3,200 feet as the minimum distance between new oil and natural gas production wells and certain sensitive receptors such as homes, schools and businesses open to the public. The law became effective January 1, 2023 and CalGEM issued emergency regulations implementing the requirements of the law on January 6, 2023. However, on February 3, 2023, the Secretary of State of California certified voter signatures collected in connection with a referendum for the November 2024 ballot to repeal Senate Bill No. 1137. As a result, any implementation of Senate Bill No. 1137 is stayed until it is put to a vote, although any stay could be delayed if there are legal challenges to the Secretary of State's certification. In addition, even during the stay, CalGEM could attempt to initiate new rulemaking with respect to setbacks. There is significant uncertainty with respect to the ability to book proved undeveloped reserves and drill within the setback zone established by Senate Bill No. 1137 and, as a result, we have only booked proved undeveloped reserves for which we already have permits within the zone and intend to develop prior to the November 2024 ballot. As of December 31, 2022, changes in our development plans due to Senate Bill No. 1137 reduced the net present value of our proved undeveloped reserves by 24% and our overall proved reserves by 4%.

Recent changes in CalGEM management have further lead to additional permitting delays and uncertainty with respect to our ability to timely obtain permits for our operations. We cannot guarantee that these issues or new ones that may arise in the future will not continue to delay or otherwise impair our ability to obtain drilling permits. In the past we have generally been able to mitigate permitting risks by building up a reserve of drilling permits for use throughout the year, but as a result of the issues described above we have not been able to build our reserve of approved permits to the same level as we have in the past. If we cannot obtain new drilling permits in a timely manner, we have limited options to meet our drilling plans, such as the use of workovers to extend the life of existing production, that may not ultimately be sufficient to achieve our business goals. Accordingly, the failure to obtain certain permits or the adoption of more stringent permitting requirements could have a material adverse effect on our business, operations, properties, results of operations, and our financial condition.

Recent and future actions by the State of California could reduce both the demand for and supply of oil and natural gas within the state and consequently have a material and adverse effect on our business, results of operations and financial condition.

In recent years, the Governor of California, the Legislature and state agencies have taken a series of actions that could materially and adversely affect the state's oil and natural gas sector. Most recently, on September 16, 2022, the Governor of California signed Senate Bill No. 1137 into law, which establishes 3,200 feet as the minimum distance between new oil and natural gas production wells and certain sensitive receptors such as homes, schools or parks. Senate Bill No. 1137 is currently stayed pending the outcome of the California General Election in November 2024. For additional information, see *Part I, Item 1 and 2 – Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

The trend in California is to impose increasingly stringent restrictions on oil and natural gas activities. We cannot predict what actions the Governor of California, the Legislature or state agencies may take in the future, but we could face increased compliance costs, delays in obtaining the approvals necessary for our operations, exposure to increased liability, or other limitations as a result of future actions by these parties. Moreover, new developments resulting from the current and future actions of these parties could also materially and adversely affect our ability to operate, successfully execute drilling plans, or otherwise develop our reserves. Accordingly, recent and future actions by the Governor of California, the Legislature, and state agencies could materially and adversely affect our business, results of operations, and financial condition.

Our business is highly regulated and government authorities can delay or deny permits and approvals or change requirements governing our operations, including hydraulic fracturing and other well stimulation methods, enhanced production techniques and fluid injection or disposal, that could increase costs, restrict operations and change or delay the implementation of our business plans.

Our operations are subject to complex and stringent federal, state, local and other laws and regulations relating to the exploration and development of our properties, as well as the production, transportation, marketing and sale of our products.

To operate in compliance with these laws and regulations, we must obtain and maintain permits, approvals and certificates from federal, state and local government authorities for a variety of activities including siting, drilling, completion, stimulation, operation, inspection, maintenance, transportation, storage, marketing, site remediation, decommissioning, abandonment, protection of habitat and threatened or endangered species, air emissions, disposal of solid and hazardous waste, fluid injection and disposal and water consumption, recycling and reuse. For example, our operations in the Wilmington Oil Field utilize injection wells to reinject produced water pursuant to waterflooding plans. These operations are subject to regulation by both the City of Long Beach and CalGEM. We are currently in discussions with the City of Long Beach and CalGEM with respect to what injection well pressure gradient complies with CalGEM's requirements for the protection of underground sources of drinking water while at the same time mitigating subsidence risks. CalGEM's local office has preliminarily indicated that the injection well pressure gradient should be reduced from the gradient that has been used for several decades. As part of our ongoing discussions, we and the City of Long Beach have provided CalGEM with technical information regarding how the historical injection well pressure gradient complies with CalGEM's requirements and to inform them of the absence of risk of leakage. If CalGEM were to ultimately disagree and determine to reduce the injection well pressure gradient, and we were unable to reverse that decision on appeal or other legal challenge, we expect that any material reduction in injection well pressure gradient for our operations in the Wilmington Oil Field would result in a decrease in production and reserves from the field.

Failure to comply may result in the assessment of administrative, civil and/or criminal fines and penalties, liability for noncompliance, costs of corrective action, cleanup or restoration, compensation for personal injury, property damage or other losses, and the imposition of injunctive or declaratory relief restricting or prohibiting certain operations or our access to property, water, minerals or other necessary resources, and may otherwise delay or restrict our operations and cause us to incur substantial costs. Under certain environmental laws and regulations, we could be subject to strict or joint and several liability for the removal or remediation of contamination, including on properties over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

Our ability to timely obtain and maintain permits for our operations, including from CalGEM, has from time to time been subject to significant delays and uncertainties and is subject to factor our control. These factors include changes in agency practices, new regulations, or legal challenges to existing approvals for our operations from individual citizens and non-governmental organizations. For example, beginning in 2021, CalGEM ceased issuing new well stimulation permits and has slowed the approval of new drill permits even as it continues approving plugging and workovers. In addition, in 2020 a group of plaintiffs challenged in court the ability of Kern County to issue well permits in reliance on an existing Environmental Impact Report (EIR). See *Part I, Item 1 and 2 – Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities.* We can also provide no assurances that we will always be able to successfully navigate these risks and timely obtain permits or obtain them on favorable terms. While we have existing permits that will allow us to run a modified drilling program in 2023, we are unlikely to be able to offset projected oil production declines over the same period.

Changes to elected or appointed officials or their priorities and policies could result in different approaches to the regulation of the oil and natural gas industry. We cannot predict the actions the Governor of California or the California legislature may take with respect to the regulation of our business, the oil and natural gas industry or the state's economic, fiscal or environmental policies, nor can we predict what actions may be taken at the federal level with respect to health, environmental safety, climate, labor or energy laws, regulations and policies, including those that may directly or indirectly impact our operations.

Our Carbon TerraVault business and our CCS projects are subject to extensive government regulation that, among other things, requires us to obtain permits for the injection and sequestration of CO_2. Many of these regulations are still being developed. Failure to comply with these requirements and obtain the necessary permits, or the development of government regulations that are unfavorable to our CCS projects, could have an adverse effect on our business, results of operations and financial condition.

Successful development of CCS projects in the United States require that we comply with what we anticipate will be a stringent regulatory scheme requiring that we obtain certain permits applicable to subsurface injection of CO_2 for geologic sequestration. Moreover, as operator of our CCS projects, we must demonstrate and maintain levels of financial assurance sufficient to cover the cost of corrective action, injection well plugging, post injection site care and site closure, and emergency and remedial response. There is no assurances that we will be successful in obtaining or maintaining permits or adequate levels of financial assurance for one or more of our CCS projects or that permits can be obtained on a timely basis, whether due to difficulty with the technical demonstrations required to obtain such permits, public opposition, or otherwise.

Separately, permitting CCS projects requires obtaining a number of other permits and approvals unrelated to subsurface injection from various U.S. federal and state agencies, such as for air emissions or impacts to environmental, natural, historic or cultural resources resulting from the construction and operation of a CCS facility. We cannot guarantee that we will be able to obtain or maintain all applicable permits for CCS activities on a timely basis or on favorable terms.

As CCS and carbon management represent an emerging sector, laws and regulations may evolve rapidly, which could impact the feasibility of one or more of our anticipated projects. To the extent additional legal or regulatory requirements are imposed, are amended, or more stringently enforced, we may incur additional costs in the pursuit of one or more of our carbon capture projects, which costs may be material or may render any one or more of our projects uneconomical.

Recent changes in California law may result in delays to our carbon capture, sequestration and storage projects.

On September 16, 2022, the Governor of California signed Senate Bill No. 905 into law, which contemplates the development of unitization, permitting and pipeline safety regulations over a multi-year period to facilitate the development of CCS projects in California, though the legislation does not provide for compulsory unitization. Protocols to support CCS are to be adopted by January 1, 2024, and a unified permit application is to be adopted by January 1, 2025. We believe our Carbon TerraVault projects, for which permits with the EPA have been filed, will continue to be developed on a timeline consistent with our initial expectations. These initial projects are not reliant on the unitization or permitting regulations being developed. In addition, our Carbon TerraVault projects are expected to either use emitters that are directly sited above these storage facilities or rely on pipelines for transporting CO_2 that will need to comply with yet to be developed CO_2 pipeline safety regulations from the federal Pipeline and Hazardous Materials Safety Administration, which could take a number of years to effect. Delays in developing required pipeline safety regulations would delay projects requiring pipeline transportation of CO_2. The lack of compulsory unitization could also delay project timelines.

The unified permitting process contemplated by Senate Bill No. 905 will be optional for project applicants and is intended to simplify the permitting process for CCS projects. In the meantime, pursuant to this legislation we are permitted to proceed with our existing and future CCS Class VI permit applications with the EPA. This law also contemplates the implementation of a new regulatory program incorporating standards that are not yet defined and that could affect the timing of future CCS projects in California.

Senate Bill No. 905 also prohibits CCS projects that utilize and permanently sequester CO_2 in connection with EOR projects. Although we do not have any existing oil and natural gas production or proved reserves associated with EOR projects, this legislation required us to transition our CalCapture project to target CCS and may require us to make other adjustments to projects in the future.

Concerns about climate change and other air quality issues may prompt governmental action that could materially affect our operations or results.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions, and regulation of GHGs and other air quality issues, may materially affect our business in many ways, including increasing the costs to provide our products and services and reducing demand for, and consumption of, our products and services, and we may be unable to recover or pass through a significant portion of our costs. In addition, legislative and regulatory responses to such issues at the federal, state and local level may increase our capital and operating costs and render certain wells or projects uneconomic, and potentially lower the value of our reserves and other assets. Both the EPA and California have implemented laws, regulations and policies that seek to reduce GHG emissions. California’s cap-and-trade program operates under a market system and the costs of such allowances per metric ton of GHG emissions are expected to increase in the future as the CARB tightens program requirements and annually increases the minimum state auction price of allowances and reduces the state’s GHG emissions cap. As the foregoing requirements become more stringent, we may be unable to implement them in a cost-effective manner, or at all.

In August 2022, President Biden signed the Act into law. The Act includes a charge on methane emissions that is expected to be applicable to the reported annual methane emissions of certain oil and natural gas facilities, above specified methane intensity thresholds, starting in 2024. The full impact of future climate regulations is uncertain at this time and it is unclear what additional actions may be taken that may have an adverse effect upon our operations.

To the extent financial markets view climate change and GHG or other emissions as an increasing financial risk, this could adversely impact our cost of, and access to, capital and the value of our stock and our assets. Current investors in oil and natural gas companies may elect in the future to shift some or all of their investments into other sectors, and institutional lenders may elect not to provide funding for oil and natural gas companies. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Additionally, in March 2022, the Securities and Exchange Commission (SEC) released a proposed rule that would establish a framework for the reporting of climate risks, targets and metrics. A final rule is expected to be released in Q2 2023, but we cannot predict the final form and substance of the rule and its requirements. The ultimate impact of the rule on our business is uncertain and upon finalization may result in additional costs to comply with any such disclosure requirements, alongside increased costs of and restrictions on access to capital.

We believe, but cannot guarantee, that our local production of oil, NGLs and natural gas will remain essential to meeting California’s energy and feedstock needs for the foreseeable future. We have also established 2030 Sustainability Goals for water recycling, renewables integration, methane emission reduction and carbon capture and sequestration in our life-of-field planning in an attempt to align with the state’s long-term goals and support our ability to continue to efficiently implement federal, state and local laws, regulations and policies, including those relating to air quality and climate, in the future. However, there can be no assurances that we will be able to design, permit, fund and implement such projects in a timely and cost-effective manner or at all, or that we, our customers or end users of our products will be able to satisfy long-term environmental, air quality or climate goals if those are applied as enforceable mandates.

The adoption and implementation of new or more stringent international, federal, state or local legislation, regulations or policies that impose more stringent standards for GHG or other emissions from our operations or otherwise restrict the areas in which we may produce oil, natural gas, NGLs or electricity or generate GHG or other emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for or the value of our products and services. Additionally, political, litigation and financial risks may result in restricting or canceling oil and natural gas production activities, incurring liability for infrastructure damages or other losses as a result of climate change, or impairing our ability to continue to operate in an economic manner. Moreover, climate change may pose increasing risks of physical impacts to our operations and those of our suppliers, transporters and customers through damage to infrastructure and resources resulting from drought, wildfires, sea level changes, flooding and other natural disasters and other physical disruptions. One or more of these developments could have a material adverse effect on our business, financial condition and results of operations.

The Inflation Reduction Act could accelerate the transition to a low-carbon economy and could impose new costs on our operations.

In August 2022, President Biden signed the Act into law. The Act contains hundreds of billions of dollars in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles and supporting infrastructure and CCS, amongst other provisions. In addition, the Act imposes the first ever federal fee on the emission of GHGs through a methane emissions charge. The Act amends the Clean Air Act to impose a fee on the emission of methane from sources required to report their GHG emissions to the EPA, including those sources in the onshore petroleum and natural gas production categories. The methane emissions charge would start in calendar year 2024 at $900 per ton of methane, increase to $1,200 in 2025, and be set at $1,500 for 2026 and each year thereafter. Calculation of the fee is based on certain thresholds established in the Act. In addition, the multiple incentives offered for various clean energy industries referenced above could further accelerate the transition of the economy away from fossil fuels towards lower- or zero-carbon emission alternatives. The methane charges and various incentives for clean energy industries could decrease demand for crude oil and natural gas, increase our compliance and operating costs and consequently materially and adversely affect our business and results of operations.

Adverse tax law changes may affect our operations.

We are subject to taxation by various tax authorities at the federal, state and local levels where we do business. New legislation could be enacted by any of these government authorities that could adversely affect our business. For example, the Act includes a new excise tax on certain repurchases of corporate stock. The 1% stock buyback excise tax applies to certain publicly traded corporations that repurchase stock from their shareholders after December 31, 2022. The amount subject to the excise tax is the fair market value of stock repurchased by such corporation net of the fair market value of any stock issued by such corporation during such taxable year. Although the application of this excise tax is not entirely clear, any redemptions made after December 31, 2022 in connection with our Share Repurchase Program will be subject to this excise tax. We do not believe that the effect of this new excise tax will be significant in 2023.

In addition, from time to time, legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain U.S. federal income tax benefits currently available to oil and natural gas exploration and production companies. Such changes have included, but have not been limited to, (i) the repeal of percentage depletion allowance for oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) an extension of the amortization period for certain geological and geophysical expenditures; (iv) the elimination of certain other tax deductions and relief previously available to oil and natural gas companies; and (v) an increase in the U.S. federal income tax rate applicable to corporations such as us. However, it is unclear whether any such changes will be enacted and, if enacted, how soon any such changes would be effective. Additionally, legislation could be enacted that imposes new fees or increases the taxes on oil and natural gas extraction, which could result in increased operating costs and/or reduced demand for our products. The passage of any such legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to natural gas and oil exploration and development or could increase costs and any such changes could have an adverse effect on our financial condition, results of operations and cash flows.

In California, there have been numerous state and local proposals for additional income, sales, excise and property taxes, including additional taxes on oil and natural gas production and a windfall profits tax on refineries. Although such proposals targeting the oil and natural gas industry have not become law, campaigns by various interest groups could lead to additional future taxes.

Risks Related to our Indebtedness

We may not be able to amend or refinance our existing debt to create more operating and financial flexibility and to enhance shareholder returns.

In light of our strategic goals and the restrictions under our existing debt, we are evaluating options to amend and extend or replace our Revolving Credit Facility, as well as refinancing options for our Senior Notes. Our ability to refinance our debt depends on a variety of factors, including our ability to access the commercial banking and debt capital markets. Changes in interest rates could also impact our ability to refinance our debt. If interest rates increase, the interest expense burden of any refinanced debt or other variable rate debt would increase even though the amount borrowed remained the same. There can be no assurances that we will be successful in amending, replacing or refinancing our existing debt on acceptable terms or at all.

Our existing and future indebtedness may adversely affect our business and limit our financial flexibility.

As of December 31, 2022, we had $600 million of total long-term debt, and additional borrowing capacity of $458 million under the Revolving Credit Facility (after taking into account $144 million of outstanding letters of credit). The terms of our Revolving Credit Facility and Senior Notes permit us to incur significant additional debt, some of which may be secured. Our level of future indebtedness could affect our business in several ways, including the following:

- limit management's discretion in operating our business and our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- require us to dedicate a portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities due to restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- limit our ability to pay dividends and repurchase shares;
- increase our vulnerability to downturns and adverse developments in our business and the economy generally;
- limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures, acquisitions, general corporate or other expenses, or to refinance existing indebtedness;
- make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings; and
- make us vulnerable to increases in interest rates as our indebtedness under the Revolving Credit Facility varies with prevailing interest rates.

Our ability to satisfy our obligations depends on our future operating performance and on economic, financial, competitive and other factors, many of which are beyond our control. Our business may not generate sufficient cash flow, and future financings may not be available to provide sufficient net proceeds, to meet these obligations or to successfully execute our business strategy.

We may not be able to generate sufficient cash to service all of our indebtedness, and may be forced to take other actions to satisfy the obligations under our indebtedness, which may not be successful.

Our earnings and cash flow could vary significantly from year to year due to the nature of our industry despite our commodity price risk-management activities. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and other commitments at that time. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt obligations. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy and initiatives of our competitors, are beyond our control as discussed in this “Risk Factors” section. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

The lenders under our Revolving Credit Facility could limit our ability to borrow and restrict our use or access to capital.

Our Revolving Credit Facility is an important source of our liquidity. Our ability to borrow under our Revolving Credit Facility is limited by our borrowing base, the size of our lenders’ commitments and our ability to comply with covenants.

The borrowing base under our Revolving Credit Facility is redetermined semi-annually by our lenders who review the value of our reserves and other factors that may be deemed appropriate. Currently, our borrowing base is set at $1.2 billion and the availability under our Revolving Credit Facility is limited by the aggregate elected commitment amount of our lenders, which as of February 1, 2023 was set at $602 million.

A reduction in our borrowing base below the aggregate commitment amount of our lenders would materially and adversely affect our liquidity and may hinder our ability to execute on our business strategy.

Restrictive covenants in our Revolving Credit Facility and the indenture governing our Senior Notes may limit our financial and operating flexibility.

Both our Revolving Credit Facility and the indenture governing our Senior Notes contain certain restrictions, which may have adverse effects on our business, financial condition, cash flows or results of operations. These restrictions limit our ability to, among other things, (i) incur additional indebtedness; (ii) pay dividends or repurchase shares; (iii) sell properties; and (iv) make capital investments.

The Revolving Credit Agreement also requires us to comply with certain financial maintenance covenants, including a leverage ratio and current ratio.

A breach of any of these restrictive covenants could result in a default under the Revolving Credit Facility and/or the Senior Notes. If a default occurs under the Revolving Credit Facility, the lenders may elect to declare all borrowings thereunder outstanding, together with accrued interest and other fees, to be immediately due and payable. If we are unable to repay our indebtedness when due or declared due, the lenders under the Revolving Credit Facility will also have the right to proceed against the collateral pledged to them to secure the indebtedness. An event of default under the Senior Notes may cause all outstanding Senior Notes to become due and payable immediately or give the trustee and the holders the right to declare all outstanding Senior Notes to become due and payable immediately.

Variable rate indebtedness under our Revolving Credit Facility subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our Revolving Credit Facility are at variable rates of interest and expose us to interest rate risk. As of December 31, 2022, we had no amounts borrowed under our Revolving Credit Facility. If in the future we borrow under the Revolving Credit Facility, then our results of operations would be sensitive to movements in interest rates. There are many economic factors outside our control that have in the past and may, in the future, impact rates of interest including publicly announced indices that underlie the interest obligations related to our Revolving Credit Facility. Factors that impact interest rates include governmental monetary policies, inflation, economic conditions, changes in unemployment rates, international disorder and instability in domestic and foreign financial markets. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same, and our results of operations would be adversely impacted. Such increases in interest rates could have a material adverse effect on our financial condition and results of operations if we borrow under the Revolving Credit Facility in the future.

Risks Related to Our Common Stock

Our ability to pay dividends and repurchase shares of our common stock is subject to certain risks.

We have adopted a cash dividend policy which anticipates a total annual dividend of $1.13 per share, payable to shareholders in quarterly increments of $0.2825 per share of common stock, subject to board authorization and declaration each quarter. In addition, as of December 31, 2022, we had remaining authorization under our Share Repurchase Program to repurchase up to $389 million of shares of our common stock, before the increase of $250 million approved by our Board of Directors on February 23, 2023. Any payment of future dividends or repurchasing shares of our common stock will be at the discretion of our Board of Directors and will depend upon, among other things, our earnings, liquidity, capital requirements, financial condition and other factors deemed relevant. Our Revolving Credit Facility and Senior Notes both limit our ability to pay dividends and repurchase shares of our common stock. In addition, cash dividend payments in the future may only be made out of legally available funds and, if we experience substantial losses, such funds may not be available. We can provide no assurances that we will continue to pay dividends at the anticipated rate or repurchase shares of our common stock within the authorized amount or at all.

The trading price of our common stock may decline, and you may not be able to resell shares of our common stock at prices equal to or greater than the price you paid or at all.

The trading price of our common stock may decline for many reasons, some of which are beyond our control. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. Numerous factors, including those referred to in this *Risk Factors* section could affect our stock price. These factors include, among other things, changes in our results of operations and financial condition; changes in commodity prices; changes in the national and global economic outlook; changes in applicable laws and regulations; variations in our capital plan; changes in financial estimates by securities analysts or ratings agencies; changes in market valuations of comparable companies; and additions or departures of key personnel.

Future issuances of our common stock could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We may sell additional shares of common stock in subsequent public or private offerings. We may also issue additional shares of common stock or convertible securities. As of December 31, 2022, we had 71,949,742 outstanding shares of common stock and 4,295,434 shares of common stock issuable upon exercise of outstanding warrants. We cannot predict the size of future issuances of our common stock or securities convertible into common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

There is an increased potential for short sales of our common stock due to the sales of shares issued upon exercise of warrants, which could materially affect the market price of the stock.

Downward pressure on the market price of our common stock that likely will result from sales of our common stock issued in connection with the exercise of warrants could encourage short sales of our common stock by market participants. Generally, short selling means selling a security, contract or commodity not owned by the seller. The seller is committed to eventually purchase the financial instrument previously sold. Short sales are used to capitalize on an expected decline in the security's price. Such sales of our common stock could have a tendency to depress the price of the stock, which could increase the potential for short sales.

The ownership position of certain of our stockholders limits other stockholders' ability to influence corporate matters and could affect the price of our common stock.

As of December 31, 2022, five of our shareholders owned at least 5% each and collectively owned approximately 40% of our common stock. As a result, each of these stockholders, or any entity to which such stockholders sell their stock, may be able to exercise significant control over matters requiring stockholder approval. Further, because of this large ownership position, if these stockholders sell their stock, the sales could depress our share price.

Sales of shares of our common stock by our executive officers could negatively impact the market price for our common stock.

Following our emergence from bankruptcy in October 2020, we granted our executive officers restricted stock units and performance stock units under our Long Term Incentive Plan. These units are settled in shares of our common stock and a significant portion of these grants vest in January 2024. Sales of our common stock by our executive officers may adversely impact the trading price of our common stock, even when done in compliance with our policies with respect to insider sales. Although we do not expect that the relatively small volume of such sales will itself significantly impact the trading price of our common stock, the market could react negatively to the announcement of such sales, which could in turn affect the trading price of our common stock.

General Risk Factors

Increasing attention to ESG matters may adversely impact our business.

Organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to evaluate their investment and voting decisions. Companies in the energy industry, and in particular those focused on oil or natural gas extraction, often do not score as well under ESG assessments compared to companies in other industries. Unfavorable ESG ratings may lead to increased negative investor sentiment toward us and to the diversion of their investment away from the fossil fuel industry to other industries which could have a negative impact on our stock price and our access to and costs of capital. To the extent ESG matters negatively impact our reputation, we may not be able to compete as effectively or recruit or retain employees, which may adversely affect our operations.

Moreover, while we may create and publish voluntary disclosures regarding ESG matters from time to time, many of the statements in those voluntary disclosures will be based on expectations and assumptions that may or may not be representative of actual risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring, and reporting on many ESG matters. Additionally, while we may also announce various voluntary ESG targets, such targets are aspirational. We may not be able to meet such targets in the manner or on such a timeline as initially contemplated, including, but not limited to as a result of unforeseen costs or technical difficulties associated with achieving such results. To the extent we do meet such targets, they may ultimately be achieved through various contractual arrangements, including the purchase of various credits or offsets that may be deemed to mitigate our ESG impact instead of actual changes in our ESG performance. However, we cannot guarantee that there will be sufficient offsets available for purchase given the increased demand from numerous businesses implementing net zero goals, or that, notwithstanding our reliance on any reputable third-party registries, that the offsets we do purchase will successfully achieve the emissions reductions they represent. Also, despite these aspirational goals, we may receive pressure from investors, lenders, or other groups to adopt more aggressive climate or other ESG-related goals, but we cannot guarantee that we will be able to implement such goals because of potential costs or technical or operational obstacles.

Public statements with respect to ESG matters, such as emissions reduction goals, other environmental targets, or other commitments addressing certain social issues, are becoming increasingly subject to heightened scrutiny from public and governmental authorities related to the risk of potential “greenwashing,” *i.e.*, misleading information or false claims overstating potential ESG benefits. As a result, we may face increased litigation risks from private parties and governmental authorities related to our ESG efforts. In addition, any alleged claims of greenwashing against us or others in our industry may lead to further negative sentiment and diversion of investments. Additionally, we could face increasing costs as we attempt to comply with and navigate further ESG-related focus and scrutiny.

Such ESG matters may also impact our customers or suppliers, which may adversely impact our business, financial condition, or results of operations.

Acquisition and disposition activities involve substantial risks.

Our acquisition activities carry risks that we may:

- not fully realize anticipated benefits due to less-than-expected reserves or production or changed circumstances;
- bear unexpected integration costs or experience other integration difficulties;
- assume liabilities that are greater than anticipated; and
- be exposed to currency, political, marketing, labor and other risks.

In connection with our acquisitions, we are often only able to perform limited due diligence. Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing for recovering the reserves, exploration potential, future commodity prices, operating costs and potential environmental, regulatory and other liabilities. Such assessments are inexact and incomplete, and we may be unable to make these assessments with a high degree of accuracy. If we are not able to make acquisitions, we may not be able to grow our reserves or develop our properties in a timely manner or at all.

We regularly review our property base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Our disposition activities carry risks that we may:

- not be able to realize reasonable prices or rates of return for assets;
- be required to retain liabilities that are greater than desired or anticipated;
- experience increased operating costs; and
- reduce our cash flows if we cannot replace associated revenue.

There can be no assurance that we will be able to divest assets on financially attractive terms or at all. Our ability to sell assets is also limited by the agreements governing our indebtedness. If we are not able to sell assets as needed, we may not be able to generate proceeds to support our liquidity and capital investments.

We may incur substantial losses and be subject to substantial liability claims as a result of pollution, environmental conditions or catastrophic events. We may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not fully insured against all risks. Our business and assets are subject to risks from natural disasters and operating risks associated with oil and natural gas exploration and production activities. Pollution or environmental conditions with respect to our operations or on or from our properties, whether arising from our operations or those of our predecessors or third parties, could expose us to substantial costs and liabilities. Such events may cause operations to cease or be curtailed and could adversely affect our business, workforce and the communities in which we operate. The cost and availability of obtain insurance for natural disasters has increased in recent years. We may be unable to obtain, or may elect not to obtain, insurance for certain risks if we believe that the cost of available insurance is excessive relative to the risks presented.

Cybersecurity attacks, systems failures, and other disruptions could adversely affect us.

We rely on electronic systems and networks to communicate, control and manage our exploration, development and production activities. We also use these systems and networks to prepare our financial management and reporting information, to analyze and store data and to communicate internally and with third parties, including our service providers and customers. If we record inaccurate data or experience infrastructure outages, our ability to communicate and control and manage our business could be adversely affected.

Cybersecurity attacks on businesses have escalated and become more sophisticated. If we or the third parties with whom we interact were to experience a successful attack, the potential consequences to our business, workforce and the communities in which we operate could be significant, including financial losses, loss of business, litigation risks and damage to reputation. We utilize various technologies, controls and procedures, as well as internal staff and external specialists to protect our systems and data, to identify and remediate vulnerabilities and to monitor and respond to threats. However, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. If a breach occurs, it may remain undetected for an extended period of time. If we or third parties with whom we interact were to experience a cybersecurity attack or a successful breach, the potential consequences could be significant, including loss of data, loss of business, damage to our reputation, potential financial or legal liability requiring us to incur significant costs, disruptions related to investigations and costs related to remediation.

Energy-related assets may be at a greater risk of strategic terrorist attacks or cybersecurity attacks than other targets. A cybersecurity attack on the digital technology that controls most oil and natural gas refining and distribution necessary to transport and market our products could impact critical distribution and storage assets or the environment, disrupt energy markets by delaying or preventing product delivery, or make it difficult or impossible to accurately account for production and settle transactions.

As cybersecurity threats continue to evolve in sophistication and magnitude, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any cybersecurity vulnerabilities. Further, state and federal cybersecurity and data privacy legislation could result in complex new requirements that increase our cost of doing business.

ITEM 1B UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 3 LEGAL PROCEEDINGS

For information regarding legal proceedings, see *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Lawsuits, Claims, Commitments and Contingencies* and *Part II, Item 8 – Financial Statements and Supplementary Data – Note 6 Lawsuits, Claims, Commitments and Contingencies*.

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 for Common Stock

Since our emergence from bankruptcy on October 27, 2020, our common stock has been listed under the symbol "CRC" on the New York Stock Exchange (NYSE). During the period from July 16, 2020 through October 26, 2020, the Predecessor company's common stock was quoted on the OTC Pink Market under the symbol "CRCQQ". Prior to July 16, 2020, the Predecessor company's common stock was listed on the NYSE under the symbol "CRC".

Holders of Record

Our common stock was held by 4 stockholders of record at January 31, 2023, which does not include the beneficial owners for whom Cede and Co. or others act as nominees.

Dividend Policy

Our Board of Directors has approved a cash dividend policy that contemplates a total annual dividend of $1.13 per share of common stock, payable to stockholders in quarterly increments of $0.2825 per share. This includes a recent amendment in the fourth quarter of 2022 to our prior dividend policy that contemplated a total quarterly dividend of $0.17 per share of common stock approved. All dividends are subject to quarterly approval by our Board of Directors and will be determined based on conditions including, our earnings, financial condition, restrictions from our Revolving Credit Facility, Senior Notes, business conditions and other factors. Based on current conditions and subject to Board approval, we expect to continue paying regular quarterly dividends of $0.2825 per share throughout 2023.

Share Repurchases

Our Board of Directors has authorized a Share Repurchase Program to acquire up to $1.1 billion of our common stock through June 30, 2024. This includes a recent increase of $250 million to our Share Repurchase Program and extension through June 30, 2024 approved by our Board of Directors on February 23, 2023. Our Share Repurchase Program does not obligate us to acquire any number of shares and may be discontinued at any time. For further information regarding our Share Repurchase Program, see *Part II, Item 7 – Management's Discussion and Analysis of Financial Results of Operations, Share Repurchase Program.* Our share repurchase activity for the year ended December 31, 2022 was as follows:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs[(a)]
January 1, 2022 - March 31, 2022	1,668,456	$ 42.52	1,668,456	$ —
April 1, 2022 - June 30, 2022	2,255,445	$ 42.57	2,255,445	—
July 1, 2022 - September 30, 2022	1,921,181	$ 41.78	1,921,181	—
October 1, 2022 - October 31, 2022	682,792	$ 42.19	682,792	—
November 1, 2022 - November 30, 2022	306,006	$ 45.77	306,006	—
December 1, 2022 - December 31, 2022	532,392	$ 42.92	532,392	—
Total 2022	7,366,272	$ 42.47	7,366,272	$ —

(a) The remaining capacity for shares that may be acquired under our Share Repurchase Program was $389 million as of December 31, 2022.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table summarizes the securities available for issuance under equity compensation plans as of December 31, 2022. A description of our stock-based compensation plans can be found in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 10 Stock-Based Compensation*.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders(1)	1,250,000	—	1,223,781
Equity compensation plan not approved by security holders(2)	2,098,436	—	7,159,304
Total	3,348,436		8,383,085

(1) Reflects shares available under our Employee Stock Purchase Plan for purchase at 85% of the lower of the market price at either (i) the beginning of a quarter or (ii) the end of a quarter.

(2) The aggregate number of 9,257,740 shares of our common stock authorized for issuance under our Long-Term Incentive Plan were approved by the Bankruptcy Court as part of the joint plan of reorganization upon our emergence from bankruptcy. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 15 Chapter 11 Proceedings* for more information on the joint plan of reorganization. The number of securities to be issued upon vesting of performance stock units assumes all units are earned upon achieving the specified 60-trading day volume weighted average prices for shares of our common stock. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 10 Stock-Based Compensation* for more information on these awards.

Performance Graph

The following graph compares the cumulative total return to stockholders on our common stock relative to the cumulative total returns of the S&P 500 and Dow Jones U.S. Exploration and Production indexes and our peer group. The graph assumes that on October 28, 2020, $100 was invested in our common stock and in each of the peer group companies' common stock weighted by their relative market capitalization, or invested on October 31, 2020 in an index, and that all dividends were reinvested. The results shown are based on historical results and are not intended to suggest future performance.

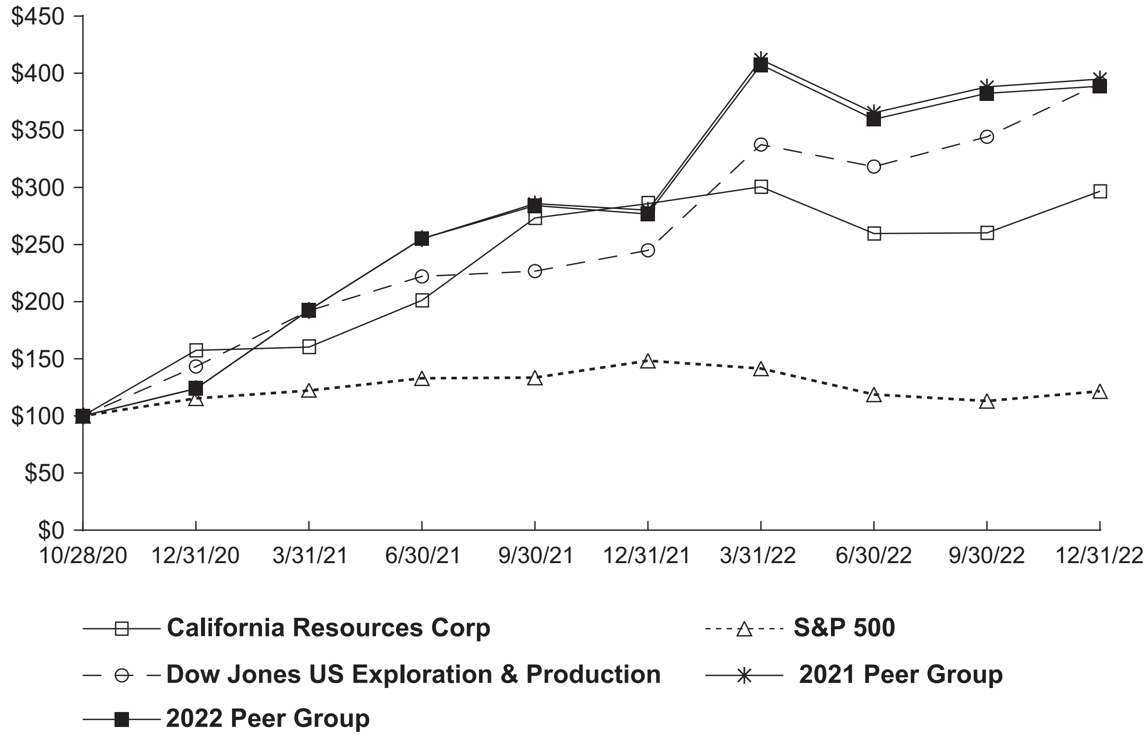
Our 2021 peer group consisted of Antero Resources Corporation; Berry Corporation; Callon Petroleum Company; Chord Energy Corp (the combination of Oasis Petroleum Inc and Whiting Petroleum Corporation which merged in 2022); Comstock Resources Inc.; Coterra Energy Inc.; Denbury Inc.; Kosmos Energy Ltd.; Magnolia Oil & Gas Corp; Matador Resources Company; Murphy Oil Corporation; PDC Energy, Inc.; Range Resources Corporation; SM Energy Company; Southwestern Energy Company; and Vermilion Energy Inc.

Our 2022 peer group consisted of Antero Resources Corporation; Berry Corporation; Callon Petroleum Company; Chord Energy Corporation; Comstock Resources Inc.; Coterra Energy Inc.; Crescent Energy Company; Denbury Inc.; Kosmos Energy Ltd.; Magnolia Oil & Gas Corp; Matador Resources Company; Murphy Oil Corporation; PDC Energy, Inc.; Range Resources Corporation; SM Energy Company; Southwestern Energy Company; Talos Energy Inc.; and Vermilion Energy Inc.

Our peer group changed from the prior year. We added Crescent Energy Company which is a newly formed company with similar market capitalization and operations. We also added Talos Energy Inc. to our peer group due to its similar financial, operational and strategic metrics as well as its presence in the carbon sequestration sector in the United States.

PERFORMANCE GRAPH*

Among California Resources Corp, the S&P 500 Index,
the Dow Jones US Exploration & Production Index,
2021 Peer Group and 2022 Peer Group



*$100 invested on 10/28/20 in stock or 10/31/20 in index, including reinvestment of dividends.
Fiscal year ending December 31.

	10/28/20	12/31/20	3/31/21	6/30/21	9/30/21	12/31/21	3/31/22	6/30/22	9/30/22	12/31/22
California Resources Corp	100.00	157.27	160.40	200.93	273.33	285.97	300.68	259.81	260.22	296.45
S&P 500	100.00	115.21	122.33	132.78	133.56	148.28	141.47	118.69	112.89	121.43
Dow Jones US Exploration & Production	100.00	143.37	192.09	221.97	226.75	245.05	337.58	318.37	344.37	391.02
2021 Peer Group	100.00	123.79	192.31	255.22	285.49	279.94	411.95	365.19	387.84	394.74
2022 Peer Group	100.00	123.98	192.30	255.07	283.86	276.93	407.17	359.56	382.17	388.55

* This performance graph shall not be deemed "soliciting material" or to be "filed" with the SEC for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liabilities under that Section, and shall not be deemed to be incorporated by reference into any filing of CRC under the Securities Act of 1933, as amended, or the Exchange Act except to the extent that we specifically request it be treated as soliciting material or specifically incorporate it by reference.

ITEM 6 RESERVED

ITEM 7 MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion should be read in conjunction with other sections of this report, including but not limited to, *Part I, Item 1 and 2 – Business and Properties* and *Part II, Item 8 – Financial Statements and Supplementary Data.*

Basis of Presentation

All financial information presented consists of our consolidated results of operations, financial position and cash flows unless otherwise indicated. We have eliminated all significant intercompany transactions and accounts. We account for our share of oil and natural gas production activities, in which we have a direct working interest by reporting our proportionate share of assets, liabilities, revenues, costs and cash flows within the relevant lines on our balance sheets and statements of operations and cash flows.

On July 15, 2020, we filed voluntary petitions for relief under Chapter 11 of Title 11 of the Bankruptcy Code. On October 13, 2020, the Bankruptcy Court confirmed our joint plan of reorganization (the Plan) and we subsequently emerged from Chapter 11 on October 27, 2020 with a new Board of Directors, new equity owners and a significantly improved financial position.

We qualified for and adopted fresh start accounting upon emergence from bankruptcy at which point we became a new entity for financial reporting purposes. We adopted an accounting convenience date of October 31, 2020 for the application of fresh start accounting. As a result of the application of fresh start accounting and the effects of the implementation of the Plan, the financial statements after October 31, 2020 may not be comparable to the financial statements prior to that date. References to "Predecessor" refer to the Company for periods ended on or prior to October 31, 2020 and references to "Successor" refer to the Company for periods subsequent to October 31, 2020. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 15 Chapter 11 Proceedings* and *Note 16 Fresh Start Accounting* for more information.

The periods November 1, 2020 through December 31, 2020 (Successor period) and January 1, 2020 through October 31, 2020 (Predecessor period) are distinct reporting periods as a result of the adoption of fresh start accounting. Certain operating results and performance measures were not significantly impacted by the reorganization. Accordingly, we believe that discussing the combined results for the two periods in 2020 is relevant and useful when making comparisons between periods for certain items such as production, realized prices, production costs and general and administrative expenses. While this combined presentation is not in accordance with generally accepted accounting principles in the United States (GAAP) and no comparable GAAP measures are presented, management believes that providing this information supplements the discussion of our results. For items that are not comparable (for example depreciation, depletion and amortization, interest expense and noncontrolling interest), our discussion addresses Predecessor and Successor results separately.

Supply Chain Constraints and Inflation

The Russia-Ukraine conflict negatively impacted the supply of steel-based raw materials which are utilized in manufacturing products used in our business. Additionally, the COVID-19 pandemic has continued to create challenges including disrupting global supply chains. These global events caused intermittent disruptions in our ability to acquire certain tools, pipe and other oilfield equipment. These disruptions resulted in cost increases but did not materially affected our development plans or operations. The continued impact on our supply chains and prices for goods is likely to continue for the foreseeable future.

Operating and capital costs in the oil and natural gas industry are heavily influenced by commodity prices. Typically, suppliers will negotiate price increases for drilling and completion services, oilfield services, equipment and materials as prices rise for energy-related commodities and raw materials (such as steel, metals and chemicals). In 2022, we experienced high single digit inflation for certain materials and services we procure from vendors including OCTG, fluid hauling, drilling equipment and mechanical and electrical labor services, among other items. We also experienced higher natural gas and electricity prices as well as increased compensation-related expenses in 2022.

We have taken measures to limit the effects of the inflationary market by entering into contracts for materials and services with terms of one to three years. Additionally, we continually look at productivity and performance improvements from our vendors in order to mitigate these price increases and also to reduce volumes consumed. We anticipate moderate price increases for certain purchased goods and services in 2023.

We continue to implement state and local county guidelines to protect the health of our workforce and to support the prevention of COVID-19 at our plants, rigs, fields and administrative offices. We have not experienced any operational slowdowns due to COVID-19 among our workforce.

Production, Prices and Realizations

The following table sets forth our average net production volumes of oil, NGLs and natural gas per day for the years ended December 31, 2022 and 2021, the Successor period from November 1, 2020 through December 31, 2020, the Predecessor period from January 1, 2020 through October 31, 2020 and the combined year ended December 31, 2020:

	Successor			Predecessor	Combined
	2022	2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	2020
Oil (MBbl/d)					
San Joaquin Basin	37	39	38	42	42
Los Angeles Basin	18	19	23	25	24
Ventura Basin	—	2	2	3	3
Total	55	60	63	70	69
NGLs (MBbl/d)					
San Joaquin Basin	11	13	12	13	13
Total	11	13	12	13	13
Natural gas (MMcf/d)					
San Joaquin Basin	129	135	138	147	145
Los Angeles Basin	1	1	1	2	2
Ventura Basin	—	4	3	4	4
Sacramento Basin	17	19	23	21	21
Total	147	159	165	174	172
Total Daily Net Production (MBoe/d)	91	100	103	112	111

The following table summarizes the changes to our total daily net production for each period presented:

	Year ended December 31, 2022	Year ended December 31, 2021
	(in MBoe/d)	
Beginning of the year	100	111
Divestitures[a]	(5)	(1)
Plant downtime[b]	(1)	—
Acquisitions[a]	1	1
PSC effect	—	(3)
Natural decline and other	(4)	(8)
Total change	(9)	(11)
End of the year	91	100

(a) See Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Divestitures and Acquisitions for more information.
(b) In the first quarter of 2022, we conducted routine maintenance at one of our gas processing facilities.

Our operating results and those of the oil and natural gas industry as a whole are heavily influenced by commodity prices. Global commodity prices increased during 2021 and continued in 2022 amid strong demand recovery from the economic impacts of COVID-19, among other factors. Oil and natural gas prices and differentials may fluctuate significantly as a result of numerous market-related variables. These and other factors make it impossible to predict realized prices reliably. The following tables set forth average benchmark prices, average realized prices and price realizations as a percentage of average benchmark prices for our products for the periods indicated below:

	Successor			
	2022		2021	
	Average Price	Realization	Average Price	Realization
Oil ($ per Bbl)				
Brent	$ 98.89		$ 70.79	
Realized price without derivative settlements	$ 98.26	99%	$ 70.43	99%
Effects of derivative settlements	(36.46)		(14.38)	
Realized price with derivative settlements	$ 61.80	62%	$ 56.05	79%
WTI	$ 94.23		$ 67.91	
Realized price without derivative settlements	$ 98.26	104%	$ 70.43	104%
Realized price with derivative settlements	$ 61.80	66%	$ 56.05	83%
NGLs ($ per Bbl)				
Realized price[(a)]	$ 64.33	65%	$ 53.62	76%
Realized price[(b)]	$ 64.33	68%	$ 53.62	79%
Natural gas				
NYMEX ($/MMBTU) - Contract Month Average	$ 6.36		$ 3.61	
Realized price without derivative settlements ($/Mcf)	$ 7.68	121%	$ 4.22	117%
Effects of derivative settlements	(0.14)		(0.02)	
Realized price with derivative settlements ($/Mcf)	$ 7.54	119%	$ 4.20	116%
NYMEX ($/MMBTU) - Average Monthly Settled Price	$ 6.64		$ 3.84	
Realized price without derivative settlements ($/Mcf)	$ 7.68	116%	$ 4.22	110%
Effects of derivative settlements	$ (0.14)		$ (0.02)	
Realized price with derivative settlements ($/Mcf)	$ 7.54	114%	$ 4.20	109%

(a) Realization is calculated as a percentage of Brent.
(b) Realization is calculated as a percentage of WTI.

	Successor		Predecessor	
	November 1, 2020 - December 31, 2020		January 1, 2020 - October 31, 2020	
	Average Price	Realization	Average Price	Realization
Oil ($ per Bbl)				
Brent	$ 47.10		$ 42.43	
Realized price without derivative settlements	$ 45.65	97%	$ 41.21	97%
Effects of derivative settlements	(0.28)		1.98	
Realized price with derivative settlements	$ 45.37	96%	$ 43.19	102%
WTI	$ 44.21		$ 38.44	
Realized price without derivative settlements	$ 45.65	103%	$ 41.21	107%
Realized price with derivative settlements	$ 45.37	103%	$ 43.19	112%
NGLs ($ per Bbl)				
Realized price[(a)]	$ 38.00	81%	$ 25.70	61%
Realized price[(b)]	$ 38.00	86%	$ 25.70	67%
Natural gas				
NYMEX ($/MMBTU) - Contract Month Average	$ 2.86		$ 1.95	
Realized price without derivative settlements ($/Mcf)	$ 3.21	112%	$ 2.11	108%
Effects of derivative settlements	(0.07)		0.06	
Realized price with derivative settlements ($/Mcf)	$ 3.14	110%	$ 2.17	111%
NYMEX ($/MMBTU) - Average Monthly Settled Price	$ 2.95		$ 1.90	
Realized price without derivative settlements ($/Mcf)	$ 3.21	109%	$ 2.11	111%
Effects of derivative settlements	$ (0.07)		$ 0.06	
Realized price with derivative settlements ($/Mcf)	$ 3.14	106%	$ 2.17	114%

(a) Realization is calculated as a percentage of Brent.
(b) Realization is calculated as a percentage of WTI.

Oil — Brent index and realized prices excluding hedge settlements were higher for the year ended December 31, 2022 compared to 2021. Capital and production discipline across domestic and international producers generally offset continued COVID-19 lockdowns in China, reduced energy demand across much of Europe and the release of meaningful quantities of oil from the United States Strategic Petroleum Reserve.

NGLs — Prices for NGLs increased in the year ended December 31, 2022 compared to 2021. Prices increased as NGL markets benefited from higher energy and fuel prices, as a whole.

Natural Gas — In 2022, natural gas prices increased both across the United States and within California compared to 2021 primarily due to strong domestic demand for power generation.

Divestitures

From time to time, we review our extensive portfolio of assets for potential divestitures. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Divestitures and Acquisitions* for more information on our transactions during years ended December 31, 2022 and 2021, the Successor period from November 1, 2020 through December 31, 2020 and the Predecessor period from January 1, 2020 through October 31, 2020.

Acquisitions and Joint Ventures

See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Investment in Unconsolidated Subsidiary and Related Party Transactions* for more information on our Carbon TerraVault JV.

See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Joint Ventures* in our 2020 Form 10-K for more information on the history of our joint ventures.

Dividend Policy

Our Board of Directors declared a cash dividend of $0.17 per share of common stock in each of the first three quarters of 2022. On November 2, 2022, our Board of Directors approved an increase in our dividend policy to an expected total annual dividend of $1.13 per share of common stock. Dividends are payable to shareholders in quarterly increments, subject to the quarterly approval of our Board of Directors. Our Board of Directors approved a quarterly cash dividend on November 2, 2022 in the amount of $0.2825 per share of common stock. For the year ended December 31, 2022, we paid $59 million in cash dividends on our common stock.

On February 23, 2023, our Board of Directors declared a cash dividend of $0.2825 per share of common stock. The dividend is payable to shareholders of record at the close of business on March 6, 2023 and is expected to be paid on March 16, 2023.

Share Repurchase Program

Our Board of Directors has authorized a Share Repurchase Program to acquire up to $850 million of our common stock through December 31, 2023. On February 23, 2023 our Board of Directors increased the Share Repurchase Program by $250 million to $1.1 billion and extended the program through June 30, 2024. The repurchases may be effected from time-to-time through open market purchases, privately negotiated transactions, Rule 10b5-1 plans, accelerated stock repurchases, derivative contracts or otherwise in compliance with Rule 10b-18, subject to market conditions. The Share Repurchase Program does not obligate us to repurchase any dollar amount or number of shares and our Board of Directors may modify, suspend, or discontinue authorization of the program at any time. Shares repurchased are held as treasury stock.

	Total Number of Shares Purchased	Dollar Value of Shares Purchased	Average Price Paid per Share
	(number of shares)	(in millions)	($ per share)
Year ended December 31, 2021	4,089,988	$ 148	$ 36.08
Year ended December 31, 2022	7,366,272	$ 313	$ 42.47
Total for 2021 and 2022	11,456,260	461	$ 40.19

See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 11 Stockholders' Equity* for more information on our share repurchase activity during the years ended December 31, 2022 and 2021.

Seasonality

Certain of our operating costs and the prices for our products fluctuate throughout the year. For example, prices for natural gas (that we both sell and purchase for use in our operations) tend to be higher in the winter and summer months. However, seasonality overall does not have a material effect on our earnings during the year.

Income Taxes

All of our income is earned from domestic operations and is subject to tax in the United States. The following table sets forth our effective tax rate on income from continuing operations:

	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
U.S. federal statutory tax rate	21%	21%	21%	21%
State income taxes, net	9	(81)	—	—
Exclusion of income attributable to noncontrolling interests	—	(1)	—	(1)
Changes in tax attributes	(2)	(8)	—	—
Executive compensation	—	2	—	—
Change in the U.S. federal valuation allowance	2	(106)	(20)	(21)
Other	1	—	(1)	1
Effective tax rate	31%	(173)%	—%	—%

For the year ended December 31, 2022, our effective rate of 31% differed from the U.S. federal statutory tax rate of 21% primarily due to state taxes and an increase in the valuation allowance for a capital loss generated from the sale of Lost Hills. In February 2023, the original tax treatment of the Lost Hills transaction was amended which allowed us to recognize the tax benefit for this loss in the first quarter of 2023. For the year ended December 31, 2021, our effective tax rate of negative 173% differed from the U.S. federal statutory tax rate of 21% primarily due to state taxes and releasing all of our valuation allowance recorded against our net deferred tax assets given our anticipated future earnings trends at that time. A portion of the change in our allowance during 2021 was for the utilization of tax benefits against current year income and the remainder was recognized as a tax benefit reflecting the projected utilization of our deferred tax assets. We did not record an income tax provision (benefit) in the period ended December 31, 2020 or the period ended October 31, 2020.

Total deferred tax assets after valuation allowance were $164 million as of December 31, 2022. Management expects to realize the recorded deferred tax assets primarily through future operating income and reversal of taxable temporary differences. We assess the realizability of our deferred tax assets each period by considering whether it is more-likely-than-not that all or a portion of our deferred tax assets will be realized. At each reporting date new evidence is considered, both positive and negative, including whether sufficient future taxable income will be generated to permit realization of existing deferred tax assets. Changes in assumptions or changes in tax laws and regulations could materially affect the realizability of our deferred tax assets.

The amount of deferred tax assets considered realizable is not assured and could be adjusted if estimates change or three-years of cumulative income is no longer present.

We expect to continue paying cash income taxes in 2023. Our tax paying status depends on a number of factors, including but not limited to, the amount and type of our capital spend, cost structure and activity levels. For additional information on tax-related items, see information set forth in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 9 Income Taxes*.

Statement of Operations Analysis

Results of Oil and Natural Gas Operations

The following table includes key operating data for our oil and natural gas operations, excluding certain corporate expenses, on a per Boe basis for the years ended December 31, 2022 and 2021, the Successor period from November 1, 2020 through December 31, 2020 and the Predecessor period from January 1, 2020 through October 31, 2020. Energy operating costs consist of purchased natural gas used to generate electricity for our operations and steam for our steamfloods, purchased electricity and internal costs to generate electricity used in our operations. Gas processing costs include costs associated with compression, maintenance and other activities needed to run our gas processing facilities at Elk Hills. Non-energy operating costs equal total operating costs less energy operating costs and gas processing costs. Purchased natural gas used to generate steam in our steamfloods was reclassified from non-energy operating costs to energy operating costs beginning in the third quarter of 2022. All prior periods have been updated to conform to this presentation.

	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
($ per Boe)				
Energy operating costs	$ 9.76	$ 7.01	$ 6.03	$ 4.71
Gas processing costs	$ 0.52	$ 0.54	$ 0.55	$ 0.55
Non-energy operating costs	$ 13.47	$ 11.84	$ 11.61	$ 9.69
Operating costs	$ 23.75	$ 19.39	$ 18.19	$ 14.95
Field general and administrative expenses(a)	$ 1.09	$ 0.94	$ 1.12	$ 1.11
Field depreciation, depletion and amortization(b)	$ 5.29	$ 5.23	$ 4.95	$ 8.75
Field taxes other than on income	$ 3.36	$ 2.83	$ 0.64	$ 3.10

(a) Excludes unallocated general and administrative expenses.

(b) Excludes depreciation, depletion and amortization related to our corporate assets, carbon management assets and Elk Hills power plant.

Energy operating costs per Boe in 2022 were higher than 2021 on a per Boe basis primarily as a result of higher electricity and natural gas prices. Lower production volumes in 2022 also contributed to the increase on a per Boe basis. Non-energy operating costs per Boe in 2022 increased as compared to 2021 primarily related to downhole maintenance activity. We expect non-energy operating costs per Boe related to maintenance activities to increase in 2023, in part due to increased costs for services, labor and supplies.

Field taxes other than on income on a per Boe basis were higher in 2022 as compared to 2021 due to increased production taxes from higher tax rates and GHG taxes which increased as market prices for GHG allowances rose. This increase was partially offset by lower ad valorem taxes.

Consolidated Results of Operations

Our consolidated results of operations include financial information related to oil and natural gas operations and our carbon management business. Our carbon management business is still in the early stages of development and was insignificant for 2021. For the year ended December 31, 2022, we have separately identified the results of our carbon management business included in consolidated general and administrative expenses and other operating expenses, net.

Year Ended December 31, 2022 vs. 2021

The following table presents our consolidated revenue and other income items:

	Year ended December 31, 2022	Year ended December 31, 2021
	(in millions)	
Oil, natural gas and NGL sales	$ 2,643	$ 2,048
Net loss from commodity derivatives	(551)	(676)
Sales of purchased natural gas	314	312
Electricity sales	261	172
Interest and other revenue	40	33
Total operating revenues	$ 2,707	$ 1,889

Oil, natural gas and NGL sales – Oil, natural gas and NGL sales, excluding the impact of settled hedges, were $2,643 million for the year ended December 31, 2022, which is an increase of 29% or $595 million, compared to $2,048 million for the year ended December 31, 2021. The increase was primarily due to higher realized prices, partially offset by lower production volumes, as shown in the following table:

	Oil	NGLs	Natural Gas	Total
		(in millions)		
Year ended December 31, 2021	$ 1,555	$ 250	$ 243	$ 2,048
Changes in realized prices	614	51	200	865
Changes in production	(201)	(37)	(32)	(270)
Year ended December 31, 2022	$ 1,968	$ 264	$ 411	$ 2,643

Note: See *Production, Prices and Realizations* for volumes and realized prices by commodity type for each period.

The effect of cash settlements on our commodity derivative contracts is not included in oil, natural gas and NGL sales. Including the effect of net payments on settled commodity derivatives described below, our oil, natural gas and NGL sales increased by $176 million or 10% in 2022 compared to the same prior year period.

Net loss from commodity derivatives – Net loss from commodity derivatives was $551 million for the year ended December 31, 2022 compared to a net loss of $676 million for the year ended December 31, 2021. The change primarily resulted from non-cash changes in the fair value of our outstanding commodity derivatives from the positions held at the end of each measurement period as well as the relationship between contract prices and the associated forward curves. Gains and losses from our commodity derivative contracts are shown in the table below:

	Year ended December 31, 2022	Year ended December 31, 2021
	(in millions)	
Non-cash commodity derivative gain (loss)	$ 187	$ (357)
Net payments on settled commodity derivatives	(738)	(319)
Net loss from commodity derivatives	$ (551)	$ (676)

Electricity sales — Electricity sales increased by $89 million to $261 million during the year ended December 31, 2022 compared to $172 million for the year ended December 31, 2021. The increase was predominantly due to higher electricity prices in 2022 resulting from higher natural gas prices.

Interest and other revenue — Other revenue increased by $7 million to $40 million for the year ended December 31, 2022, compared to $33 million for the year ended December 31, 2021 primarily due to increased sales of purchased NGL volumes which were acquired to meet our delivery commitments while one of our cryogenic gas processing facilities was down for planned maintenance in the first quarter of 2022.

The following table presents our consolidated expenses, income tax (provision) benefit and income attributable to noncontrolling interest:

	Year ended December 31, 2022	Year ended December 31, 2021
	(in millions)	
Operating expenses		
Energy operating costs	$ 323	$ 255
Gas processing costs	17	20
Non-energy operating costs	445	430
General and administrative expenses	222	200
Depreciation, depletion and amortization	198	213
Asset impairments	2	28
Taxes other than on income	162	145
Exploration expense	4	7
Purchased natural gas expense	273	196
Electricity generation expenses	167	96
Transportation costs	50	51
Accretion expense	43	50
Other operating expenses, net	48	29
Total operating expenses	$ 1,954	$ 1,720
Net gain on asset divestitures	59	124
Operating income (loss)	812	293
Non-operating (expenses) income		
Reorganization items, net	—	(6)
Interest and debt expense	(53)	(54)
Net (loss) gain on early extinguishment of debt	—	(2)
Loss from investment in unconsolidated subsidiary	(1)	—
Other non-operating expenses, net	3	(2)
Income (loss) before income taxes	761	229
Income tax (provision) benefit	(237)	396
Net income (loss)	$ 524	$ 625
Net (income) loss attributable to noncontrolling interests	$ —	$ (13)

Energy operating costs – Energy operating costs were $323 million for the year ended December 31, 2022, which was an increase of 27% or $68 million compared to $255 million for the year ended December 31, 2021. The increase was predominantly a result of higher prices for purchased natural gas, which we use to generate electricity for our operations and steam for our steamfloods, and for purchased electricity.

Non-energy operating costs – Non-energy operating costs for the year ended December 31, 2022 were $445 million, which was an increase of $15 million or 3% from $430 million for the year ended December 31, 2021 was primarily a result of increased surface and downhole maintenance activity in 2022.

General and administrative expenses – General and administrative expenses were $222 million for the year ended December 31, 2022, which was an increase of $22 million from $200 million for the year ended December 31, 2021. The increase in G&A expenses was primarily attributable to compensation-related expenses and additional headcount related to developing our carbon management business. The table below shows the portion of total G&A expenses which are directly attributable to our carbon management business:

	Year ended December 31,	
	2022	2021
	(in millions)	
Exploration and production, corporate and other	$ 210	$ 200
Carbon management business	12	—
Total general and administrative expenses	$ 222	$ 200

Depreciation, depletion and amortization – Depreciation, depletion and amortization decreased $15 million to $198 million for the year ended December 31, 2022 from $213 million for the same prior year period. The decrease was primarily the result of a lower carrying value in our exploration and production assets due to asset divestitures which occurred during the fourth quarter of 2021 and the first quarter of 2022. For further detail about our asset divestitures see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Divestitures and Acquisitions.*

Asset impairments – Asset impairments were $2 million for the year ended December 31, 2022 compared to $28 million for the year ended December 31, 2021. The asset impairment charge in 2022 related to the write-down of a commercial office building located in Bakersfield, California to fair market value. For the year ended December 31, 2021 we recorded a write-down of $25 million related to the same commercial office building and a $3 million write-off of capitalized costs related to projects which were abandoned. The decline in asset value of our commercial office building primarily related to limited demand for office space of this size and type in the Bakersfield market and general trends in commercial real estate in 2021 due to the COVID-19 pandemic. For further detail about our asset impairments see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Property, Plant and Equipment*.

Taxes other than on income – Taxes other than on income were $162 million for the year ended December 31, 2022, which was an increase of $17 million from $145 million for the year ended December 31, 2021. Taxes other than on income were higher in 2022 due to increased production taxes from higher tax rates and GHG taxes which increased as market prices for GHG allowances rose. This increase was partially offset by a decrease in ad valorem taxes.

Purchased natural gas expense – Purchased natural gas expense was $273 million for the year ended December 31, 2022, which was an increase of $77 million, or 39%, from $196 million for the year ended December 31, 2021 primarily due to higher prices in 2022 for purchased natural gas related to our trading activities.

Electricity generation expense – Electricity generation expenses increased to $167 million for the year ended December 31, 2022 from $96 million for the year ended December 31, 2021. The increase of $71 million, or 74%, was predominantly a result of higher natural gas prices used in electricity generation.

Other operating expenses, net – Other operating expenses, net was $48 million for the year ended December 31, 2022, which was an increase of $19 million, or 66%, from $29 million for the year ended December 31, 2021. The table below shows the portion of other operating expenses, net directly attributable to our carbon management business:

	Year ended December 31,	
	2022	2021
	(in millions)	
Exploration and production, corporate and other	$ 34	$ 29
Carbon management business	14	—
Total other operating expenses, net	$ 48	$ 29

Other operating expenses, net for exploration and production, corporate and other includes higher maintenance costs for offshore platforms and purchased NGL volumes which were acquired to meet our delivery commitments while one of our cryogenic gas processing facilities was undergoing maintenance. The prior comparative period included $15 million of severance costs related to the reduction in our workforce and the departure of certain executive and other senior officers. Other operating expense, net for our carbon management business includes lease cost for sequestration easements, advocacy, and other startup-related costs.

Net gain on asset divestitures – Net gain on asset divestitures for the year ended December 31, 2022 was $59 million primarily related to the sale of our 50% non-operated working interest in certain horizons within our Lost Hills field and certain Ventura basin assets. Gain on asset divestitures for the year ended December 31, 2021 was $124 million related to the sale of the majority of our Ventura basin operations, unimproved land and other non-core assets. For more information on our asset divestitures, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Divestitures and Acquisitions.*

Income tax (provision) benefit – The income tax provision for the year ended December 31, 2022 was $237 million (effective tax rate of 31%), which included a $35 million provision for a valuation allowance recorded in the first quarter of 2022 at the time of our Lost Hills divestiture. This compares to an income tax benefit of $396 million for the year ended December 31, 2021 which included the release of a valuation allowance in the fourth quarter of 2021. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 9 Income Taxes* for more information on our ability to realize deferred tax assets.

Net income attributable to noncontrolling interests – BSP's preferred interest in the BSP JV was automatically redeemed in full in September 2021 and income was allocated to BSP up to the redemption date. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 11 Stockholders' Equity* for more information on the redemption of the preferred member interest from BSP.

Year Ended December 31, 2021 vs. the Successor and Predecessor Periods of 2020

See *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Statement of Operations Analysis* in our 2021 Form 10-K for our analysis of the changes in our consolidated statements of operations for the year ended December 31, 2021 compared to the Successor period from November 1, 2020 through December 31, 2020 and the Predecessor period from January 1, 2020 through October 31, 2020 along with supplemental information for the combined year ended December 31, 2020.

Liquidity and Capital Resources

Liquidity

Our primary sources of liquidity and capital resources are cash flows from operations, cash and cash equivalents on hand and available borrowing capacity under our Revolving Credit Facility which matures in April 2024. We also generated additional cash flow of $80 million from strategic asset divestitures during 2022. Our primary uses of operating cash flow for 2022 were capital investments, repurchase shares of our common stock and dividends.

The following table summarizes our liquidity:

	December 31, 2022
	(in millions)
Cash and cash equivalents	$ 307
Revolving Credit Facility:	
Borrowing capacity	602
Outstanding letters of credit	(144)
Availability	$ 458
Liquidity	$ 765

The aggregate commitments from our Revolving Credit Facility increased to $602 million from $492 million at December 31, 2021 due to additional commitments from new lenders that joined this facility. As of December 31, 2022, we were in compliance with all of the covenants of our Revolving Credit Facility. For a description of the terms and conditions of our long-term debt, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Debt.*

We consider our low leverage and ability to adjust our capital plan and overall spending to be a core strength and strategic advantage, which we are focused on maintaining. At current commodity prices, we expect to generate operating cash flow to support and invest in our core assets and preserve financial flexibility. We regularly review our financial position and evaluate whether we may (i) increase investments in our drilling program to accelerate value, (ii) return available cash to shareholders through dividends or stock buybacks to the extent permitted under our Revolving Credit Facility and Senior Notes indenture, (iii) advance carbon management activities, or (iv) maintain cash on our balance sheet. We believe we have sufficient sources of liquidity to meet our obligations for the next twelve months. See *Other Uses of Cash* below for our long-term obligations.

We are evaluating options to amend and extend or replace our Revolving Credit Facility, as well as refinancing options for our Senior Notes, which we expect to provide us with greater operating and financial flexibility to bolster our ongoing shareholder return program. We also intend to pursue financing options for our carbon management business that are separate from the rest of our business.

Derivatives

Significant changes in oil and natural gas prices may have a material impact on our liquidity. Our hedging strategy seeks to mitigate our exposure to commodity price volatility and ensure our financial strength and liquidity by protecting our operating cash flows. Prior to April 2022, our Revolving Credit Facility included covenants that required us to maintain a certain level of hedges at all times. We also entered into hedges above and beyond those that were required for certain periods. In prior years, these hedges prevented us from realizing the full benefits of price increases. Our existing hedges, including the 2023 hedges entered into by us in 2020 to comply with our Revolving Credit Facility, may also negatively impact our realized prices in the future. Following an amendment to our Revolving Credit Facility in April 2022, we are only required to maintain hedges in the event the ratio of our consolidated total debt to consolidated EBITDAX (as defined in our Revolving Credit Facility) exceeds 1:1. As of December 31, 2022, this ratio was not exceeded. We will continue to evaluate our hedging strategy based on prevailing market prices and conditions.

Unless otherwise indicated, we use the term “hedge” to describe derivative instruments that are designed to achieve our hedging requirements and program goals, even though they are not accounted for as cash-flow or fair-value hedges. We did not have any commodity derivatives designated as accounting hedges as of and during the year ended December 31, 2022.

Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives* for more information on our open derivative contracts as of December 31, 2022 and *Note 4 Debt* for more information on an amendment to the hedging requirements included in our Revolving Credit Facility.

Uses of Cash

2023 Capital Program

We expect our 2023 capital program to range between $200 and $245 million assuming normal operating conditions. Of this amount, $165 to $195 million is related to oil and natural gas development (including approximately $10 to $15 million to build replacement water injection facilities which will allow us to use one of our depleted oil and natural gas reservoirs for CCS), $5 to $15 million for carbon management projects and $30 to $35 million for corporate and other activities (including procuring long-lead time items for planned maintenance at our Elk Hills power plant in 2024). We expect our capital program related to oil and natural gas development to be focused primarily on executing projects using existing permits outside of Kern County. The foregoing amounts related to carbon management projects do not include amounts funded by Brookfield through the Carbon TerraVault JV. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Investment in Unconsolidated Subsidiary and Related Party Transactions* for more information on our joint venture with Brookfield.

The actual amount of spending under our 2023 capital program will depend on a variety of factors. In particular, our ability to obtain additional permits during the course of the year may cause us to adjust our capital spending. There are also a number of other factors that could affect the size of our capital program, including other changes in regulation and permitting, commodity prices, the success of our drilling program, operating costs and other general market conditions. In particular, as the Kern County EIR Litigation remains ongoing and in order to reduce the uncertainty surrounding permitting in Kern County, we will seek CEQA permits for updated field level EIRs to reduce reliance on the Kern County EIR in future years. Because we own and operate substantially all of our assets, the amount and timing of our capital spending is largely within our control and we are able to shift our development activities to projects so as to minimize the impact of external factors. Any curtailment of the development of our oil and natural gas properties for regulatory or operational reasons could lead to a decline in our production and may lower our reserves. A continued decline in our production and reserves would negatively impact our cash flow from operations and the value of our assets.

Other Uses of Cash

Other than our 2023 capital program, our expected material uses of cash during 2023 include: (1) dividends and share repurchases; (2) settlements on commodity derivative contracts; (3) income taxes; (4) settlement of asset retirement obligations; (5) funds used in operations; and (6) costs related to advancing our carbon management activities not included in our capital program, such as employee costs and engineering studies.

The table below summarizes our current and long-term material cash requirements as of December 31, 2022 that we expect to fund with operating cash flow (in millions):

	Payments Due by Year				
	Total	Less than 1 Year	Years 2 and 3	Years 4 and 5	More than 5 Years
			(in millions)		
On-Balance Sheet					
Long-term debt[(a)]	$ 600	$ —	$ —	$ 600	$ —
Interest on long-term debt	132	43	85	4	—
Pension and postretirement[(b)]	86	14	18	15	39
Operating leases[(c)]	85	21	27	17	20
Off-Balance Sheet					
Purchase obligations[(d)]	112	61	15	11	25
Total	$ 1,015	$ 139	$ 145	$ 647	$ 84

(a) Represents the outstanding long-term debt balance as of December 31, 2022. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Debt* for more information on our long-term debt agreements.
(b) Represents undiscounted future obligations for defined benefit and post-employment benefit plans.
(c) Our operating leases include drilling rigs, commercial office space, fleet vehicles, easements and certain facilities.
(d) Reflects amounts that will become due under long-term agreements to purchase goods and services used in the normal course of business. Purchase obligations for pipeline capacity include ship or pay arrangements that are based on contractual volumes and current market rates for firm transportation capacity during the contract period. Oil and natural gas leases reflect obligations for fixed payments under our contracts.

Cash Flow Analysis

Cash flows from operating activities – Our net cash provided by operating activities is sensitive to many variables, particularly changes in commodity prices. Commodity price movements may also lead to changes in other variables in our business, including adjustments to our capital program.

Our operating cash flow for the year ended December 31, 2022 was $690 million, which was an increase of $30 million, or 5%, from $660 million for the year ended December 31, 2021. The increase was primarily related to higher average realized prices (including the effects of settlements on our commodity derivatives) partially offset by declining production and increased operating costs. The increase in operating costs in 2022 as compared to 2021 primarily related to higher prices for purchased natural gas and electricity used in our operations as well as cost increases we experienced due to inflation.

Cash flows from investing activities – The table below summarizes net cash used in investing activities:

	Year ended December 31, 2022	Year ended December 31, 2021
	(in millions)	
Capital investments	$ (379)	$ (194)
Changes in capital accruals	1	20
Proceeds from divestitures, net	80	67
Acquisitions	(17)	(52)
Distributions related to the Carbon TerraVault JV	12	—
Capitalized joint venture transaction costs	(12)	—
Other	(2)	(2)
Net cash used in investing activities	$ (317)	$ (161)

The increase in the use of cash primarily related to a higher capital program in 2022 as compared to 2021. In 2022, we invested $16 million in our carbon management activities including $12 million to build replacement water injection facilities which will allow us to use one of our depleted oil and natural gas reservoirs for CCS. Proceeds from divestitures, net for the year ended December 31, 2022 included the sale of our 50% non-operated working interest in certain horizons within our Lost Hills field, certain of our Ventura basin assets and our commercial office building in Bakersfield, California. We sold the majority of our Ventura basin operations in 2021 and other non-core assets including unimproved land. In 2022, our acquisitions related to our carbon management business. In 2021, we acquired working interests in certain joint venture wells held by MIRA. *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Divestitures and Acquisitions* for more information on our divestitures and acquisitions.

Cash flows from financing activities – The table below summarizes net cash used by financing activities:

	Year ended December 31, 2022	Year ended December 31, 2021
	(in millions)	
Debt transactions	$ —	$ (12)
Distributions to noncontrolling interest holders	—	(50)
Repurchases of common stock	(313)	(148)
Issuance of common stock	1	2
Common stock dividends	(59)	(14)
Net cash used by financing activities	$ (371)	$ (222)

Our net cash used in financing activities for the year ended December 31, 2022 related to repurchases of our common stock under our Share Repurchase Program and dividends. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 11 Stockholders' Equity* for more information on our cash dividends.

Our net cash used in financing activities for the year ended December 31, 2021 primarily related to distributions to BSP as well as repurchases of our common stock under our Share Repurchase Program. *Part II, Item 8 – Financial Statements and Supplementary Data, Note 11 Stockholders' Equity* for additional information on our BSP JV.

Lawsuits, Claims, Commitments and Contingencies

We are involved, in the normal course of business, in lawsuits, environmental and other claims and other contingencies that seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2022 and 2021 were not material to our consolidated balance sheets as of such dates.

In October 2020, Signal Hill Services, Inc. defaulted on its decommissioning obligations associated with two offshore platforms. The Bureau of Safety and Environmental Enforcement (BSEE) determined that former lessees, including our former parent, Occidental Petroleum Corporation (Oxy) with a 37.5% share, are responsible for accrued decommissioning obligations associated with these offshore platforms. Oxy sold its interest in the platforms approximately 30 years ago and it is our understanding that Oxy has not had any connection to the operations since that time and challenged BSEE's order. Oxy notified us of the claim under the indemnification provisions of the Separation and Distribution Agreement between us and Oxy. In September 2021, we accepted the indemnification claim from Oxy and we are now appealing the order from BSEE.

We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves cannot be accurately determined.

See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 6 Lawsuits, Claims, Commitments and Contingencies*.

Critical Accounting Estimates

Our critical accounting estimates that could result in a material impact to the consolidated financial statements due to the levels of subjectivity and management judgment include the following:

Title	Description	Estimation and Uncertainties	Sensitivities
Oil and Natural Gas Properties	The carrying value of our property, plant and equipment represents the costs incurred to acquire or develop the asset, including any asset retirement obligations, net of accumulated depreciation, depletion and amortization and impairment charges, if any. We use the successful efforts method of accounting for our oil and gas producing activities. Under this method, we capitalize the costs of acquiring properties, development costs and the costs of drilling successful exploration wells. The estimated amount of proved reserve volumes are used as the basis for recording depletion expense. We determine depletion on our oil and natural gas producing properties using the unit-of-production method. Under this method, acquisition costs are amortized based on total proved oil and gas reserves and capitalized development and successful exploration costs are depleted based on proved developed oil and natural gas reserves. Future cash flows from expected reserve volumes for producing properties may be used in an impairment analysis or a determination of whether sufficient future taxable income will be generated to permit realization of existing deferred tax assets. We also use reserves to predict when a producing well will become inactive, and then idle, to schedule the timing of abandonment in estimating certain of our asset retirement obligations.	The determination of quantities of proved reserves is a highly technical process performed by our petroleum engineers and geoscientists. The analysis is based on drilling results, reservoir performance, subsurface interpretation and future development plans. Production rate forecasts are primarily derived from estimates from decline-curve analysis and type-curve analysis. Secondary inputs may include material balance calculations, which consider the volumes of substances replacing the volumes produced and associated reservoir pressure changes. Additional inputs may also include seismic analysis and computer simulations of reservoir performance. These field-tested technologies have demonstrated reasonably certain results with consistency and repeatability in the formations being evaluated or in analogous formations. The data for a given reservoir may also change over time as a result of numerous factors including, but not limited to, additional development activity and future development costs, production history and continuous reassessment of the viability of future production volumes under varying economic conditions. Several other factors could change our proved oil and gas reserves including changes in energy costs, inflation, deflation and the political and regulatory environment, all of which are beyond our control.	Our total proved reserves were 417 MMBoe and our total proved developed reserves were 363 MMBoe at December 31, 2022. We estimate our 2023 depletion rate for oil and natural gas producing properties using the unit-of-production method will be approximately $5.80/Boe. A 5% change in our reserves would increase or decrease this DD&A rate by approximately $0.30/Boe. If realized prices used in our year-end reserve estimates increased or decreased by 10%, our proved reserve quantities at December 31, 2022 would have increased by 3 MMBoe or decreased by 4 MMBoe, respectively.

Title	Description	Estimation and Uncertainties	Sensitivities
Asset Retirement Obligations	The majority of our asset retirement obligations relate to the plugging and abandonment of oil and natural gas wells. We determine our asset retirement obligation for oil and natural gas wells by calculating the present value of estimated future cash outflows related to the abandonment obligation. The asset retirement cost is capitalized as part of the carrying amount of the related long-lived asset. In periods subsequent to initial measurement, the asset retirement cost is depreciated using the unit-of-production method, while increases in the ARO liability resulting from the passage of time (accretion expense) is included in operating expenses on our consolidated statements of operations.	The recognition of an asset retirement obligation requires us to make assumptions including an estimate of future abandonment costs and inflation rates, timing of activity and our credit-adjusted discount rate among others. Changes in the legal, regulatory and political environment could also affect our estimated future cash outflows.	As of December 31, 2022 and 2021, we had asset retirement obligations of \$491 million and \$489 million, respectively. Excluding liabilities associated with our assets held for sale, a 1% increase in the inflation rate would increase our liability by \$32 million and a 1% decrease in the inflation rate would decrease our liability by \$29 million as of December 31, 2022.

FORWARD-LOOKING STATEMENTS

This document contains statements that we believe to be "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than historical facts are forward-looking statements, and include statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and plans and objectives of management for the future. Words such as "expect," "could," "may," "anticipate," "intend," "plan," "ability," "believe," "seek," "see," "will," "would," "estimate," "forecast," "target," "guidance," "outlook," "opportunity" or "strategy" or similar expressions are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements.

Although we believe the expectations and forecasts reflected in our forward-looking statements are reasonable, they are inherently subject to numerous risks and uncertainties, most of which are difficult to predict and many of which are beyond our control. No assurance can be given that such forward-looking statements will be correct or achieved or that the assumptions are accurate or will not change over time. Particular uncertainties that could cause our actual results to be materially different than those expressed in our forward-looking statements include:

- fluctuations in commodity prices, including supply and demand considerations for our products and services;
- decisions as to production levels and/or pricing by OPEC or U.S. producers in future periods;
- government policy, war and political conditions and events, including the war in Ukraine and oil sanctions on Russia, Iran and others;
- regulatory actions and changes that affect the oil and gas industry generally and us in particular, including (1) the availability or timing of, or conditions imposed on, permits and approvals necessary for drilling or development activities or our carbon management business; (2) the management of energy, water, land, greenhouse gases (GHGs) or other emissions, (3) the protection of health, safety and the environment, or (4) the transportation, marketing and sale of our products;
- the impact of inflation on future expenses and changes generally in the prices of goods and services;
- changes in business strategy and our capital plan;
- lower-than-expected production or higher-than-expected production decline rates;
- changes to our estimates of reserves and related future cash flows, including changes arising from our inability to develop such reserves in a timely manner, and any inability to replace such reserves;
- the recoverability of resources and unexpected geologic conditions;
- general economic conditions and trends, including conditions in the worldwide financial, trade and credit markets;
- production-sharing contracts' effects on production and operating costs;
- the lack of available equipment, service or labor price inflation;
- limitations on transportation or storage capacity and the need to shut-in wells;
- any failure of risk management;
- results from operations and competition in the industries in which we operate;
- our ability to realize the anticipated benefits from prior or future efforts to reduce costs;
- environmental risks and liability under federal, regional, state, provincial, tribal, local and international environmental laws and regulations (including remedial actions);
- the creditworthiness and performance of our counterparties, including financial institutions, operating partners, CCS project participants and other parties;

- reorganization or restructuring of our operations;
- our ability to claim and utilize tax credits or other incentives in connection with our CCS projects,
- our ability to realize the benefits contemplated by our energy transition strategies and initiatives, including CCS projects and other renewable energy efforts;
- our ability to successfully identify, develop and finance carbon capture and storage projects and other renewable energy efforts, including those in connection with the Carbon TerraVault JV;
- our ability to successfully develop infrastructure projects and enter into third party contracts on contemplated terms; and
- uncertainty around the accounting of emissions and our ability to successfully gather and verify emissions data and other environmental impacts.
- changes to our dividend policy and share repurchase program, and our ability to declare future dividends or repurchase shares under our debt agreements;
- limitations on our financial flexibility due to existing and future debt;
- insufficient cash flow to fund our capital plan and other planned investments and return capital to shareholders;
- changes in interest rates;
- our access to and the terms of credit in commercial banking and capital markets, including our ability to refinance our debt or obtain separate financing for our carbon management business;
- changes in state, federal or international tax rates, including our ability to utilize our net operating loss carryforwards to reduce our income tax obligations;
- effects of hedging transactions;
- the effect of our stock price on costs associated with incentive compensation;
- inability to enter into desirable transactions, including joint ventures, divestitures of oil and natural gas properties and real estate, and acquisitions, and our ability to achieve any expected synergies;
- disruptions due to earthquakes, forest fires, floods or other natural occurrences, accidents, mechanical failures, power outages, transportation or storage constraints, labor difficulties, cybersecurity breaches or attacks or other catastrophic events;
- pandemics, epidemics, outbreaks, or other public health events, such as the COVID-19; and
- other factors discussed in *Part I, Item 1A – Risk Factors.*

We caution you not to place undue reliance on forward-looking statements contained in this document, which speak only as of the filing date, and we undertake no obligation to update this information. This document may also contain information from third party sources. This data may involve a number of assumptions and limitations, and we have not independently verified them and do not warrant the accuracy or completeness of such third-party information.

ITEM 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our financial results are sensitive to fluctuations in oil, NGL and natural gas prices. These commodity price changes also impact the volume changes under PSCs. We maintain a commodity hedging program primarily focused on crude oil to help protect our cash flows, margins and capital program from the volatility of crude oil prices. We have not designated any instruments as hedges for accounting purposes and we do not enter into such instruments for speculative trading purposes. We believe we have limited price volatility risk in the near term as a result of our current hedges in place. As of December 31, 2022, we had hedges on approximately 65% of our anticipated oil production through 2023 and approximately 5% through 2024, which are in line with the covenants of our Revolving Credit Facility.

The primary market risk relating to our derivative contracts relates to fluctuations in market prices as compared to the fixed contract price for a notional amount of our production. As of December 31, 2022, we had net liabilities of $200 million for our derivative commodity positions which are carried at fair value, using industry-standard models with various inputs, including the forward curve for the relevant price index. We estimate that a $10/bbl increase in Brent oil forward prices could increase our settlement payments by $123 million in 2023, limiting our upside. We estimate that a $10 decrease in Brent oil forward prices could decrease our settlement payments by $137 million in 2023, negating the downside price movement for hedged volumes.

A summary of our Brent-based crude oil derivative contracts at December 31, 2022 are included in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives*.

Counterparty Credit Risk

Our counterparty credit risk relates primarily to trade receivables and derivative financial instruments. Credit exposure for each counterparty is monitored for outstanding balances and current activity. Counterparty credit limits have been established based upon the financial health of counterparties, and these limits are actively monitored. In the event counterparty credit risk is heightened, we may request collateral or accelerate payment dates for product deliveries. Approximately 60% of our production during 2022 was oil which was sold predominately to refineries in California. Trade receivables for all commodities are collected within 30 to 60 days following the month of delivery. For derivative instruments entered into as part of our hedging program, we are subject to counterparty credit risk to the extent the counterparty is unable to meet its settlement commitments. We have master netting agreements with each of our derivative counterparties, which allows us to net our settlement payments for the same commodity with the same counterparty. Therefore, our loss is limited to the net amount due from a defaulting counterparty. All of our counterparties in the hedging program have an investment grade credit rating. Concentration of credit risk is regularly reviewed to ensure that counterparty credit risk is adequately diversified.

Interest-Rate Risk

We had no variable-rate debt outstanding as of December 31, 2022. Due to rising interest rates, we may be limited in amending, replacing or refinancing our existing Revolving Credit Facility and Senior Notes at favorable terms if at all.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
California Resources Corporation:

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of California Resources Corporation and subsidiaries (the Company) as of December 31, 2022 and December 31, 2021, the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity (deficit), and cash flows for each of the years in the two-year period ended December 31, 2022 (Successor), for the period from November 1, 2020 to December 31, 2020 (Successor), and for the period from January 1, 2020 to October 31, 2020 (Predecessor), and the related notes and financial statement schedule II (collectively, 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.

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 December 31, 2021, and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2022 (Successor), for the period from November 1, 2020 to December 31, 2020 (Successor), and for the period from January 1, 2020 to October 31, 2020 (Predecessor), in conformity with U.S. generally accepted accounting principles. 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 Committee of Sponsoring Organizations of the Treadway Commission.

New Basis of Presentation

As discussed in Notes 1 and 15 to the consolidated financial statements, the Company emerged from Chapter 11 bankruptcy on October 27, 2020 with a reporting date of October 31, 2020. Accordingly, the accompanying consolidated financial statements as of December 31, 2022, 2021, and 2020 have been prepared in conformity with Accounting Standards Codification Topic 852, *Reorganizations*, with the Company's assets, liabilities, and capital structure having carrying amounts that are not comparable with prior periods.

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 the accompanying Management's Annual Assessment of and Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

Critical Audit Matters

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

Impact of estimated oil and gas reserves on depletion expense for proved oil and gas properties

As discussed in Note 1 to the consolidated financial statements, the Company determines depletion of oil and gas producing properties by the unit-of-production method. Under this method, acquisition costs are amortized based on total proved oil and gas reserves and capitalized development and successful exploration costs are amortized based on proved developed oil and gas reserves. The Company recorded depreciation, depletion, and amortization expense of $198 million for the year ended December 31, 2022 (Successor). Estimating proved oil and gas reserves requires the expertise of professional petroleum reservoir engineers, who take into consideration estimates of future production, operating and development costs and commodity prices inclusive of market differentials. The Company employs technical personnel, such as reservoir engineers and geoscientists, who estimate proved oil and gas reserves. The Company also engages independent reservoir engineering specialists to perform an independent evaluation of the Company s proved oil and gas reserves estimates.

We identified the assessment of estimated proved oil and gas reserves on the determination of depreciation, depletion and amortization expense for proved oil and gas properties as a critical audit matter. Complex auditor judgment was required to evaluate the Company's estimate of proved oil and gas reserves, which is an input to the determination of depreciation, depletion, and amortization expense. Specifically, auditor judgment was required to evaluate the assumptions used by the Company related to estimated future oil and gas production, future commodity prices inclusive of market differentials, and future operating and development costs.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design of certain internal controls related to the Company's depletion process, including controls related to the estimation of proved oil and gas reserves. We evaluated (1) the professional qualifications of the Company's internal reservoir engineers, as well as the independent reservoir engineering specialists and external engineering firm, (2) the knowledge, skills, and ability of the Company's internal and independent reservoir engineers, and (3) the relationship of the independent reservoir engineering specialists and external engineering firms to the Company. We assessed the methodology used by the technical personnel employed by the Company and the independent reservoir engineering specialists to estimate the reserves used in the determination of depreciation, depletion and amortization expense for compliance with industry and regulatory standards. We compared estimated future oil and gas production and estimated future operating and development costs estimated by the technical personnel employed by the Company to historical results. We compared the commodity prices used by the Company's internal technical personnel to publicly available prices and recalculated the relevant market differentials based on actual price realizations. We read and considered the reports of the independent reservoir engineering specialists in connection with our evaluation of the Company's proved oil and gas reserves estimates.

Assessment of control of the Carbon TerraVault Joint Venture under the variable interest entity model

As discussed in Note 1, if an entity is determined to be a Variable Interest Entity (VIE) but the Company does not have a controlling financial interest, the entity is accounted for under the equity method. As discussed in Note 8, the Company accounts for its investment in the Carbon TerraVault Joint Venture (Carbon TerraVault JV) under the equity method of accounting. As of December 31, 2022, the Company's carrying value of its equity method investment in the Carbon TerraVault JV was $13 million.

We identified the evaluation of control of the Carbon TerraVault JV as a critical audit matter. Identifying the activities of the VIE that most significantly impact its economic performance and evaluating whether the Company had the ability to direct these activities required a high degree of subjective auditor judgment.

The following are the primary procedures we performed to address the critical audit matter. We evaluated the design and tested the operating effectiveness of internal controls over the evaluation of technical accounting matters, including the evaluation of control for the Carbon TerraVault JV transaction. We obtained the Company's accounting analysis and compared the relevant information in the analysis to the joint venture agreements and other underlying documentation, including the Company's evaluation of the significant activities of the Carbon TerraVault JV and which party has the power to direct those activities. We inspected the relevant joint venture agreements and evaluated the Company's determination of whether power is shared.

/s/ KPMG LLP

We have served as the Company's auditor since 2014.

Los Angeles, California
February 24, 2023

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets
As of December 31, 2022 and 2021
(in millions, except share data)

	2022	2021
CURRENT ASSETS		
Cash	$ 307	$ 305
Trade receivables	326	245
Inventories	60	60
Assets held for sale	5	22
Receivable from affiliate	33	—
Other current assets, net	133	121
Total current assets	864	753
PROPERTY, PLANT AND EQUIPMENT	3,228	2,845
Accumulated depreciation, depletion and amortization	(442)	(246)
Total property, plant and equipment, net	2,786	2,599
INVESTMENT IN UNCONSOLIDATED SUBSIDIARY	13	—
DEFERRED TAX ASSETS	164	396
OTHER NONCURRENT ASSETS	140	98
TOTAL ASSETS	$ 3,967	$ 3,846
CURRENT LIABILITIES		
Accounts payable	345	266
Liabilities associated with assets held for sale	5	21
Fair value of derivative contracts	246	270
Accrued liabilities	298	297
Total current liabilities	894	854
NONCURRENT LIABILITIES		
Long-term debt, net	592	589
Fair value of derivative contracts	—	132
Asset retirement obligations	432	438
Other long-term liabilities	185	145
STOCKHOLDERS' EQUITY		
Preferred stock (20 million shares authorized at $0.01 par value); no shares outstanding at December 31, 2022 or 2021	—	—
Common stock (200 million shares authorized at $0.01 par value); (83,406,002 and 83,389,210 shares issued; 71,949,742 and 79,299,222 shares outstanding at December 31, 2022 and 2021, respectively)	1	1
Treasury stock (11,456,260 shares held at cost at December 31, 2022 and 4,089,988 shares held at December 31, 2021)	(461)	(148)
Additional paid-in capital	1,305	1,288
Retained earnings	938	475
Accumulated other comprehensive income	81	72
Total stockholders' equity	1,864	1,688
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 3,967	$ 3,846

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations
For the years ended December 31, 2022 and 2021, the period from November 1, 2020 through December 31, 2020 and the period from January 1, 2020 through October 31, 2020
(in millions, except share and per share data)

	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
REVENUES				
Oil, natural gas and NGL sales	$ 2,643	$ 2,048	$ 237	$ 1,092
Net (loss) gain from commodity derivatives	(551)	(676)	(141)	91
Sales of purchased natural gas	314	312	38	124
Electricity sales	261	172	15	86
Interest and other revenue	40	33	3	14
Total operating revenues	2,707	1,889	152	1,407
OPERATING EXPENSES				
Operating costs	785	705	114	511
General and administrative expenses	222	200	40	212
Depreciation, depletion and amortization	198	213	34	328
Asset impairments	2	28	—	1,736
Taxes other than on income	162	145	10	134
Exploration expense	4	7	1	10
Purchased natural gas expense	273	196	24	78
Electricity generation expenses	167	96	10	53
Transportation costs	50	51	8	35
Accretion expense	43	50	8	33
Other operating expenses, net	48	29	9	56
Total operating expenses	1,954	1,720	258	3,186
Net gain on asset divestitures	59	124	—	—
OPERATING INCOME (LOSS)	812	293	(106)	(1,779)
NON-OPERATING (EXPENSES) INCOME				
Reorganization items, net	—	(6)	(3)	4,060
Interest and debt expense	(53)	(54)	(11)	(206)
Net (loss) gain on early extinguishment of debt	—	(2)	—	5
Loss from investment in unconsolidated subsidiary	(1)	—	—	—
Other non-operating income (expenses), net	3	(2)	(5)	(84)
INCOME (LOSS) BEFORE INCOME TAXES	761	229	(125)	1,996
Income tax (provision) benefit	(237)	396	—	—
NET INCOME (LOSS)	524	625	(125)	1,996
NET (INCOME) LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS				
Mezzanine equity	—	—	—	(94)
Stockholders' equity	—	(13)	2	(13)
Net (income) loss attributable to noncontrolling interests	—	(13)	2	(107)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 524	$ 612	$ (123)	$ 1,889
Net income (loss) attributable to common stock per share				
Basic	$ 6.94	$ 7.46	$ (1.48)	$ 40.59
Diluted	$ 6.75	$ 7.37	$ (1.48)	$ 40.42
Weighted-average common shares outstanding				
Basic	75.5	82.0	83.3	49.4
Diluted	77.6	83.0	83.3	49.6

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Comprehensive Income (Loss)
For the years ended December 31, 2022 and 2021, the period from November 1, 2020 through December 31, 2020 and the period from January 1, 2020 through October 31, 2020
(in millions)

	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
Net income (loss)	$ 524	$ 625	$ (125)	$ 1,996
Net (income) loss attributable to noncontrolling interests	—	(13)	2	(107)
Other comprehensive income (loss):				
Actuarial gains (losses) associated with pension and postretirement plans	13	16	(8)	(2)
Prior service credit	—	65	—	2
Amortization of prior service cost credit included in net periodic benefit cost	(4)	(1)	—	—
Comprehensive income (loss) attributable to common stock	$ 533	$ 692	$ (131)	$ 1,889

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Changes in Stockholders' Equity (Deficit)
For the years ended December 31, 2022 and 2021, the period from November 1, 2020 through December 31, 2020 and the period from January 1, 2020 through October 31, 2020
(in millions)

	Predecessor							
	Common Stock	Treasury Stock	Additional Paid-in Capital	Accumulated (Deficit) Earnings	Accumulated Other Comprehensive (Loss) Income	Equity Attributable to Common Stock	Equity Attributable to Noncontrolling Interests	Total (Deficit) Equity
Balance, December 31, 2019	$ —	$ —	$ 5,004	$ (5,370)	$ (23)	$ (389)	$ 93	$ (296)
Net income	—	—	—	1,889	—	1,889	13	1,902
Distributions to noncontrolling interest holders	—	—	—	—	—	—	(37)	(37)
Shared-based compensation, net	—	—	10	—	—	10	—	10
Modification of noncontrolling interest	—	—	138	—	—	138	—	138
Gain on acquisition of noncontrolling interest	—	—	128	—	—	128	—	128
Issuance of Successor common stock for acquisition of a noncontrolling interest in connection with the Plan	—	—	261	—	—	261	—	261
Issuance of Successor common stock to creditors in connection with the Plan	—	—	408	—	—	408	—	408
Issuance of Subscription Rights to creditors in connection with the Plan	—	—	71	—	—	71	—	71
Issuance of Successor common stock for junior debtor-in-possession exit fee	—	—	12	—	—	12	—	12
Issuance of Successor common stock to Subscription Rights holders and backstop parties in connection with the Plan, net	1	—	445	—	—	446	—	446
Warrants issued in connection with the Plan	—	—	15	—	—	15	—	15
Fair value adjustment related to noncontrolling interest	—	—	—	—	—	—	7	7
Elimination of Predecessor equity	—	—	(5,224)	3,481	23	(1,720)	—	(1,720)
Balance, October 31, 2020	$ 1	$ —	$ 1,268	$ —	$ —	$ 1,269	$ 76	$ 1,345

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

	Successor							
	Common Stock	Treasury Stock	Additional Paid-in Capital	Accumulated (Deficit) Earnings	Accumulated Other Comprehensive (Loss) Income	Equity Attributable to Common Stock	Equity Attributable to Noncontrolling Interests	Total Equity
Balance, October 31, 2020	$ 1	$ —	$ 1,268	$ —	$ —	$ 1,269	$ 76	$ 1,345
Net loss	—	—	—	(123)	—	(123)	(2)	(125)
Distributions to noncontrolling interest holder	—	—	—	—	—	—	(30)	(30)
Other comprehensive loss	—	—	—	—	(8)	(8)	—	(8)
Balance, December 31, 2020	$ 1	$ —	$ 1,268	$ (123)	$ (8)	$ 1,138	$ 44	$ 1,182
Net income	—	—	—	612	—	612	13	625
Distributions to noncontrolling interest holder	—	—	—	—	—	—	(50)	(50)
Cash dividends ($0.17 per share)	—	—	—	(14)	—	(14)	—	(14)
Redemption of noncontrolling interest[(a)]	—	—	7	—	—	7	(7)	—
Share-based compensation	—	—	13	—	—	13	—	13
Repurchases of common stock	—	(148)	—	—	—	(148)	—	(148)
Issuance of common stock	—	—	2	—	—	2	—	2
Other	—	—	(2)	—	—	(2)	—	(2)
Other comprehensive income	—	—	—	—	80	80	—	80
Balance, December 31, 2021	$ 1	$ (148)	$ 1,288	$ 475	$ 72	$ 1,688	$ —	$ 1,688
Net income	—	—	—	524	—	524	$ —	524
Cash dividends ($0.7925 per share)	—	—	—	(61)	—	(61)	$ —	(61)
Share-based compensation	—	—	19	—	—	19	$ —	19
Repurchases of common stock	—	(313)	—	—	—	(313)	$ —	(313)
Other	—	—	(2)	—	—	(2)	$ —	(2)
Other comprehensive income, net of tax	—	—	—	—	9	9	$ —	9
Balance, December 31, 2022	$ 1	$ (461)	$ 1,305	$ 938	$ 81	$ 1,864	$ —	$ 1,864

(a) The remaining balance in equity attributable to noncontrolling interest was reallocated to additional paid-in capital of the parent upon redemption of ECR's preferred member interest in the BSP JV. No gain or loss was recognized on the equity transaction. See *Note 15 Chapter 11 Proceedings* for more information.

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows
For the years ended December 31, 2022 and 2021, the period from November 1, 2020 through December 31, 2020 and the period from January 1, 2020 through October 31, 2020
(in millions)

	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
CASH FLOW FROM OPERATING ACTIVITIES				
Net income (loss)	$ 524	$ 625	$ (125)	$ 1,996
Adjustments to reconcile net income (loss) to net cash provided (used) by operating activities:				
Depreciation, depletion and amortization	198	213	34	328
Deferred income tax provision (benefit)	226	(396)	—	—
Asset impairments	2	28	—	1,736
Net loss (gain) from commodity derivatives	551	676	141	(91)
Net settlement (payments) proceeds from commodity derivatives	(738)	(319)	(1)	108
Net loss (gain) on early extinguishment of debt	—	2	—	(5)
Amortization of deferred gain	—	—	—	(39)
Net gain on asset divestitures	(59)	(124)	—	—
Other non-cash charges to income, net	43	62	27	60
Reorganization items, net (non-cash)	—	—	—	(4,128)
Reorganization items, net (debtor-in-possession financing costs)	—	—	—	25
Changes in operating assets and liabilities, net:				
(Increase) decrease in trade receivables	(81)	(68)	(28)	128
Decrease (increase) in inventories	—	—	1	(1)
Decrease (increase) in other current assets	35	(47)	6	2
(Decrease) increase in accounts payable and accrued liabilities	(11)	8	(67)	(1)
Net cash provided (used) by operating activities	690	660	(12)	118
CASH FLOW FROM INVESTING ACTIVITIES				
Capital investments	(379)	(194)	(7)	(40)
Changes in accrued capital investments	1	20	(1)	(24)
Proceeds from asset divestitures	80	67	—	41
Acquisitions	(17)	(52)	—	—
Distribution related to the Carbon TerraVault JV	12	—	—	—
Capitalized joint venture transaction costs	(12)	—	—	—
Other	(2)	(2)	1	(7)
Net cash used in investing activities	(317)	(161)	(7)	(30)
CASH FLOW FROM FINANCING ACTIVITIES				
Proceeds from 2014 Revolving Credit Facility	—	—	—	797
Repayments of 2014 Revolving Credit Facility	—	—	—	(1,315)
Proceeds from debtor-in-possession facilities	—	—	—	802
Repayments of debtor-in-possession facilities	—	—	—	(802)
Proceeds from Revolving Credit Facility	—	16	82	225
Repayments of Revolving Credit Facility	—	(115)	(208)	—
Proceeds from Second Lien Term Loan	—	—	—	200
Debtor-in-possession financing costs	—	—	—	(25)
Proceeds from Senior Notes	—	600	—	—
Debt repurchases	—	—	—	(3)
Debt issuance costs	—	(13)	—	(20)

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

Repayment of Second Lien Term Loan	—	(200)	—	—
Repayment of EHP Notes	—	(300)	—	—
Repayment of 2020 Senior Notes	—	—	—	(100)
Contributions from noncontrolling interest holders	—	—	—	—
Distributions to noncontrolling interest holders	—	(50)	(30)	(104)
Repurchases of common stock	(313)	(148)	—	—
Common stock dividends	(59)	(14)	—	—
Acquisition of noncontrolling interest in connection with the Plan	—	—	—	(2)
Issuance of common stock	1	2	—	446
Shares cancelled for taxes and other	—	—	—	(1)
Net cash (used) provided by financing activities	(371)	(222)	(156)	98
Increase (decrease) in cash	2	277	(175)	186
Cash—beginning of period	305	28	203	17
Cash—end of period	$ 307	$ 305	$ 28	$ 203

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

NOTE 1 NATURE OF BUSINESS, SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND OTHER

Nature of Business

We are an independent oil and natural gas exploration and production company operating properties exclusively within California. We are committed to energy transition and have some of the lowest carbon intensity production in the United States. We are in the early stages of permitting several carbon capture and storage projects in California. Our subsidiary Carbon TerraVault is expected to build, install, operate and maintain CO_2 capture equipment, transportation assets and storage facilities in California. In August 2022, Carbon TerraVault entered into a joint venture with BGTF Sierra Aggregator LLC (Brookfield) to pursue certain of these opportunities (Carbon TerraVault JV). See *Joint Ventures and Investments in Unconsolidated Subsidiaries* below for our accounting policy related to joint ventures and investments in unconsolidated subsidiaries and *Note 8 Investments and Related Party Transactions* for more information on the Carbon TerraVault JV. Separately, we are evaluating the feasibility of a carbon capture system to be located at our Elk Hills power plant (CalCapture).

Except when the context otherwise requires or where otherwise indicated, all references to ‘‘CRC,’’ the ‘‘Company,’’ ‘‘we,’’ ‘‘us’’ and ‘‘our’’ refer to California Resources Corporation and its subsidiaries.

Basis of Presentation

We have prepared this report in accordance with United States (U.S.) generally accepted accounting principles (U.S. GAAP) and the rules and regulations of the U.S. Securities and Exchange Commission applicable to annual financial information.

All financial information presented consists of our consolidated results of operations, financial position and cash flows. We have eliminated significant intercompany transactions and balances. We account for our share of oil and natural gas producing activities, in which we have a direct working interest, by reporting our proportionate share of assets, liabilities, revenues, costs and cash flows within the relevant lines on our consolidated financial statements.

We qualified for and adopted fresh start accounting upon emergence from Chapter 11 in October 2020 at which point we became a new entity for financial reporting purposes. We adopted an accounting convenience date of October 31, 2020 for the application of fresh start accounting.

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 October 31, 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 October 31, 2020 and references to “Successor” refer to the Company for periods subsequent to October 31, 2020. See *Note 15 Chapter 11 Proceedings* and *Note 16 Fresh Start Accounting* for additional information on our bankruptcy proceedings and the impact of fresh start accounting on our consolidated financial statements.

Use of Estimates

The process of preparing financial statements in conformity with U.S. GAAP requires management to select appropriate accounting policies and make informed estimates and judgments regarding certain types of financial statement balances and disclosures. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements and judgments on expected outcomes as well as the materiality of transactions and balances. Changes in facts and circumstances or discovery of new information relating to such transactions and events may result in revised estimates and judgments. Further, actual results may differ from estimates upon settlement. Management believes that these estimates and judgments provide a reasonable basis for the fair presentation of our consolidated financial statements.

Risks and Uncertainties

Our revenue, profitability and future growth or our oil and natural gas operations are substantially dependent upon prevailing and future prices for oil and natural gas, which can be volatile and dependent on factors beyond our control including global production inventories, available storage and transportation capacities, government regulation, the Russia-Ukraine conflict and economic conditions. The Coronavirus Disease 2019 (COVID-19) pandemic continues to create price volatility for oil and natural gas. The ongoing impacts from the Russia-Ukraine conflict and COVID-19 on our financial position, results of operations and cash flows will depend on uncertain factors, including future developments that are beyond our control. We are in the early stages of developing a carbon capture and sequestration business which is subject to risks as an emerging industry. We operate exclusively in California which is a highly regulated environment.

Concentration of Customers

We sell crude oil, natural gas and NGLs to marketers, California refineries and other customers that have access to transportation and storage facilities. In light of the ongoing energy deficit in California and strong demand for native crude oil production, we do not believe that the loss of any single customer would have a material adverse effect on our consolidated financial statements taken as a whole.

For the year ended December 31, 2022, three California refineries each accounted for at least 10%, and collectively 52%, of our sales (before the effects of hedging). For the year ended December 31, 2021, three California refineries each accounted for at least 10%, and collectively accounted for 51%, of our sales (before the effects of hedging). For the 2020 Successor period, three California refineries each accounted for at least 10%, and collectively accounted for 50%, of our sales (before the effects of hedging). For the 2020 Predecessor period, two California refineries, each accounted for at least 10%, and collectively accounted for 46%, of our sales (before the effects of hedging).

Recently Adopted Accounting and Disclosure Changes

ASC Topic 848, *Reference Rate Reform* contains guidance for applying U.S. GAAP to contracts, hedging relationships and other transactions that are impacted by reference rate reform. Under this guidance, we elected to account for the February 2022 amendment of our Revolving Credit Facility described in *Note 4 Debt* as a modification of the original instrument. The debt modification did not have a material impact to our consolidated financial statements.

Significant Accounting Policies

Restructuring under Chapter 11 of the Bankruptcy Code and Workforce Reductions

On July 15, 2020, we filed voluntary petitions for relief under Chapter 11 of Title 11 of the Bankruptcy Code (Chapter 11 Cases) in the United States Bankruptcy Court for the Southern District of Texas, Houston Division (Bankruptcy Court). On October 13, 2020, the Bankruptcy Court confirmed our joint plan of reorganization (the Plan) and we subsequently emerged from Chapter 11 proceedings on October 27, 2020 (Effective Date). See *Note 15 Chapter 11 Proceedings* for more information on our voluntary reorganization. We qualified for fresh start accounting and allocated the reorganization value to our individual assets and liabilities based on their estimated relative fair value. Our reorganization value was less than the fair value of identifiable assets of the emerging entity and we allocated the difference to nonfinancial assets on a relative fair value basis. Our valuation approach for determining the estimated fair value of our significant assets acquired and liabilities assumed is discussed in *Note 16 Fresh Start Accounting*.

In 2021, we reduced the size of our management team and realigned several functions, which resulted in headcount and cost reductions. We recorded a restructuring charge of $15 million during the year ended December 31, 2021. In 2020, we reduced our workforce in response to economic conditions, resulting in a restructuring charge of $10 million in the Predecessor period ended October 31, 2020 and $5 million in the Successor period ended December 31, 2020. These charges are included in other operating expenses, net on our consolidated statement of operations.

Property, Plant and Equipment (PP&E)

We use the successful efforts method to account for our oil and natural gas properties. Under this method, we capitalize costs of acquiring properties, costs of drilling successful exploration wells and development costs. The costs of exploratory wells, including permitting, land preparation and drilling costs, are initially capitalized pending a determination of whether we find proved reserves. If we find proved reserves, the costs of exploratory wells remain capitalized. Otherwise, we charge the costs of the related wells to expense. In cases where we cannot determine whether we have found proved reserves at the completion of exploration drilling, we conduct additional testing and evaluation of the wells. We generally expense the costs of such exploratory wells if we do not find proved reserves within a one-year period after initial drilling has been completed.

Proved Reserves – Proved reserves are those quantities of oil and natural gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a specific date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. We have no proved oil and natural gas reserves for which the determination of economic producibility is subject to the completion of major capital investments.

Several factors could change our proved oil and natural gas reserves. For example, for long-lived properties, higher commodity prices typically result in additional reserves becoming economic and lower commodity prices may lead to existing reserves becoming uneconomic. Estimation of future production and development costs is also subject to change partially due to factors beyond our control, such as energy costs and inflation or deflation of oil field service costs. These factors, in turn, could lead to changes in the quantity of proved reserves. Additional factors that could result in a change of proved reserves include production decline rates and operating performance differing from those estimated when the proved reserves were initially recorded as well as availability of capital to implement the development activities contemplated in the reserves estimates and changes in management’s plans with respect to such development activities.

We perform impairment tests with respect to proved properties when product prices decline other than temporarily, reserves estimates change significantly, other significant events occur or management's plans change with respect to these properties in a manner that may impact our ability to realize the recorded asset amounts. Impairment tests incorporate a number of assumptions involving expectations of undiscounted future cash flows, which can change significantly over time. These assumptions include estimates of future product prices, which we base on forward price curves and, when applicable, contractual prices, estimates of oil and natural gas reserves and estimates of future expected operating and development costs. Any impairment loss would be calculated as the excess of the asset's net book value over its estimated fair value. We recognize any impairment loss on proved properties by adjusting the carrying amount of the asset.

Unproved Properties – When we make acquisitions that include unproved properties, we assign values based on estimated reserves that we believe will ultimately be proved. As exploration and development work progresses and if reserves are proved, we transfer the book value from unproved to proved based on the initially determined rate per BOE. If the exploration and development work were to be unsuccessful, or management decided not to pursue development of these properties as a result of lower commodity prices, higher development and operating costs, regulatory changes, contractual conditions or other factors, the capitalized costs of the related properties would be expensed.

Impairments of unproved properties are primarily based on qualitative factors including intent of property development, lease term and recent development activity. The timing of impairments on unproved properties, if warranted, depends upon management's plans, the nature, timing and extent of future exploration and development activities and their results. We recognize any impairment loss on unproved properties by providing a valuation allowance.

Depreciation, Depletion and Amortization – We determine depreciation, depletion and amortization (DD&A) of oil and natural gas producing properties by the unit-of-production method. Our unproved reserves are not subject to DD&A until they are classified as proved properties. We amortize acquisition costs over total proved reserves, and capitalized development and successful exploration costs over proved developed reserves. Our gas and power plant assets are depreciated over the estimated useful lives of the assets, using the straight-line method, with expected initial useful lives of the assets of up to 30 years. We depreciated other property and equipment using the straight-line method based on expected useful lives of the individual assets or group of assets. The useful lives typically include ranges of 4-10 years for leasehold improvements, 1-4 years for software and telecommunications equipment and up to 5 years for computer hardware.

We expense annual lease rentals, the costs of injection used in production and exploration, and geological, geophysical and seismic costs as incurred. Costs of maintenance and repairs are expensed as incurred, except that the costs of replacements that expand capacity or add proven oil and natural gas reserves are capitalized.

Fair Value Measurements

Our assets and liabilities measured at fair value are categorized in a three-level fair-value hierarchy, based on the inputs to the valuation techniques:

Level 1—using quoted prices in active markets for the assets or liabilities;
Level 2—using observable inputs other than quoted prices for the assets or liabilities; and
Level 3—using unobservable inputs.

Transfers between levels, if any, are recognized at the end of each reporting period. We apply the market approach for certain recurring fair value measurements, maximize our use of observable inputs and minimize use of unobservable inputs. We generally use an income approach to measure fair value when observable inputs are unavailable. This approach utilizes management's judgments regarding expectations of projected cash flows and discount rates.

Commodity derivatives are carried at fair value. We utilize the mid-point between bid and ask prices for valuing these instruments. Our commodity derivatives comprise over-the-counter bilateral financial commodity contracts, which are generally valued using industry-standard models that consider various inputs, including quoted forward prices for commodities, time value, volatility factors, credit risk and current market and contracted prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable data or are supported by observable prices based on transactions executed in the marketplace. We classify these measurements as Level 2. Commodity derivatives are the most significant items on our consolidated balance sheets affected by recurring fair value measurements.

Our PP&E may be written down to fair value if we determine that there has been an impairment. The fair value is determined as of the date of the assessment generally using discounted cash flow models based on management's expectations for the future. Inputs include estimates of future production, prices based on commodity forward price curves, inclusive of market differentials, as of the date of the estimate, estimated future operating and development costs and a risk-adjusted discount rate.

The carrying amounts of cash and other on-balance sheet financial instruments, other than fixed-rate debt, approximate fair value.

Revenue Recognition

We derive substantially all of our revenue from sales of oil, natural gas and NGLs and associated hedging activities, with the remaining revenue generated from sales of electricity and trading activities related to storage and managing excess pipeline capacity. Revenues are recognized when control of promised goods is transferred to our customers, in an amount that reflects the consideration we expect to receive in exchange for those goods.

Commodity sales contracts — Disaggregated revenue for sales of oil, natural gas and natural gas liquids (NGLs) to customers includes the following:

(in millions)	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
Oil	$ 1,968	$ 1,555	$ 176	$ 874
NGLs	264	250	29	106
Natural gas	411	243	32	112
Oil, natural gas and NGL sales	$ 2,643	$ 2,048	$ 237	$ 1,092

See *Note 14 Revenue* for more information on our revenue from contracts with customers.

Joint Ventures and Investments in Unconsolidated Subsidiaries

We may enter into joint ventures that are considered to be a variable interest entity (VIE). A VIE is a legal entity that possesses any of the following conditions: the entity's equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity's economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity's expected losses or the right to receive the legal entity's expected residual returns. We consolidate a VIE if we determine that we have (i) the power to direct the activities of the VIE that most significantly impact its economic performance and (ii) the obligation to absorb losses or the right to receive benefits from the VIE that are more than insignificant to the VIE. If an entity is determined to be a VIE but we do not have a controlling interest, the entity is accounted for under either the cost or equity method depending on whether we exercise significant influence. See *Note 8 Investment in Unconsolidated Subsidiary and Related Party Transactions* for more information on the Carbon TerraVault JV. These evaluations are highly complex and involve management judgment and may involve the use of estimates and assumptions based on available information. The evaluation requires continual assessment.

Investments in unconsolidated entities are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value may have occurred, which is other than temporary.

Allowance for Credit Losses

Our receivables from customers relate to sales of our commodity products, trading activities and joint interest billings. Credit exposure for each customer is monitored for outstanding balances and current activity. We actively manage our credit risk by selecting counterparties that we believe to be financially sound and continue to monitor their financial health. Concentration of credit risk is regularly reviewed to ensure that counterparty credit risk is adequately diversified. We believe exposure to counterparty credit-related losses at December 31, 2022 was not material and losses associated with counterparty credit risk have been insignificant for all periods presented.

Inventories

Materials and supplies, which primarily consist of well equipment and tubular goods used in our oil and natural gas operations, are valued at weighted-average cost and are reviewed periodically for obsolescence. Finished goods predominantly comprise oil and natural gas liquids (NGLs), which are valued at the lower of cost or net realizable value. Inventories, by category, are as follows:

	2022	2021
	(in millions)	
Materials and supplies	$ 56	$ 54
Finished goods	4	6
Total	$ 60	$ 60

Derivative Instruments

The fair value of our derivative contracts are netted when a legal right of offset exists with the same counterparty with an intent to offset. Since we did not apply hedge accounting to our commodity derivatives for any of the periods presented, we recognized fair value adjustments, on a net basis, in our consolidated statements of operations. Unless otherwise indicated, we use the term “hedge” to describe derivative instruments that are designed to achieve our hedging program goals, even though they are not accounted for as cash-flow or fair-value hedges.

Stock-Based Incentive Plans

The shares issuable under our long-term incentive plan were authorized by the Bankruptcy Court and the terms of a new long-term incentive plan were approved by our new board of directors in January 2021. In accordance with our new long-term incentive plan, we reserved 9,257,740 shares of common stock (subject to adjustment) for future issuances to certain executives, employees and non-employee directors that are more fully described in *Note 10 Stock-Based Compensation*.

Earnings Per Share

Basic earnings (loss) per share is calculated as net income (loss) divided by the weighted average number of our common shares outstanding during the period. Diluted earnings (loss) per share is calculated by dividing net income (loss) by the weighted average number of our common shares outstanding including the effect of dilutive potential common shares. We compute basic and diluted earnings per share (EPS) using the two-class method required for participating securities, when applicable, and the treasury stock method when participating securities are not in place. Certain restricted and performance stock awards are considered participating securities when such shares have non-forfeitable dividend rights, which participate at the same rate as common stock.

Under the two-class method, net income allocated to participating securities is subtracted from net income attributable to common stock in determining net income available to common stockholders. In loss periods, no allocation is made to participating securities because the participating securities do not share in losses.

Asset Retirement Obligations

We recognize the fair value of asset retirement obligations (ARO) in the period in which a determination is made that a legal obligation exists to dismantle an asset and reclaim or remediate the property at the end of its useful life and the cost of the obligation can be reasonably estimated. The fair value of the retirement obligation is based on future retirement cost estimates and incorporates many assumptions such as time of abandonment, current regulatory requirements, technological changes, future inflation rates and a risk-adjusted discount rate. When the liability is initially recorded, we capitalize the cost by increasing the related PP&E balances. If the estimated future cost or timing of cash flow changes, we adjust the fair value of the liability and PP&E. Over time the liability is increased, and expense is recognized for accretion. The cost capitalized to PP&E is recovered over either the useful life of our facilities or the unit-of-production method for our minerals.

We have asset retirement obligations for certain of our facilities, which includes plant and field decommissioning, and the plugging and abandonment of wells. In certain cases, we will recognize ARO in the periods in which sufficient information becomes available to reasonably estimate their fair values. Additionally, for certain plants, we do not have a legal obligation to decommission them and, accordingly, we have not recorded a liability.

The following table presents a rollforward of our ARO.

(in millions)	Year ended December 31, 2022	Year ended December 31, 2021
Beginning balance	$ 489	$ 597
Liabilities settled and divested	(57)	(157)
Accretion expense on discounted obligation	43	50
Revisions of estimated obligation	15	(11)
Additions	6	30
Other	(5)	1
Liabilities associated with assets held for sale	—	(21)
Ending balance	$ 491	$ 489
Current portion	$ 59	$ 51
Non-current portion	$ 432	$ 438

During 2022, our total asset retirement obligation increased by $2 million from 2021. Our liabilities settled and divested in 2022 of $57 million, included $40 million for settlement payments and $17 million of liabilities assumed related to our Lost Hills divestiture. Revisions of our estimated obligation increased $15 million, which reflect higher anticipated future abandonment costs, including inflation and changes in the timing of settlement.

During 2021, our total asset retirement obligation decreased by $108 million from 2020. Our liabilities settled and divested in 2021 of $157 million included $42 million for settlement payments and $115 million of liabilities assumed as part of our Ventura divestiture. Our liabilities included $30 million of additions, partially offset by $21 million of liabilities reclassified as held for sale. Revisions to our future cost estimates and abandonment dates for our oil and natural gas assets resulted in a decrease of $11 million.

See *Note 3 Divestitures and Acquisitions* for more information on our sold properties and our liabilities reclassified as held for sale.

Loss Contingencies

In the normal course of business, we are involved in lawsuits, claims and other environmental and legal proceedings and audits. We accrue reserves for these matters when it is probable that a liability has been incurred and the liability can be reasonably estimated. In addition, we disclose, if material, in aggregate, our exposure to losses in excess of the amount recorded on the balance sheet for these matters if it is reasonably possible that an additional material loss may be incurred. We review our loss contingencies on an ongoing basis.

Loss contingencies are based on judgments made by management with respect to the likely outcome of these matters and are adjusted as appropriate. Management's judgments could change based on new information, changes in, or interpretations of, laws or regulations, changes in management's plans or intentions, opinions regarding the outcome of legal proceedings, or other factors.

Income Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax basis. Deferred tax assets are recognized when it is more likely than not that they will be realized. We periodically assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets will not be realized.

We recognize the financial statement effects of tax positions when it is more likely than not, based on the technical merits, that the position will be sustained upon examination by a tax authority. We recognize interest and penalties, if any, related to uncertain tax positions as a component of the income tax provision. No interest or penalties related to uncertain tax positions were recognized in the financial statements for the periods presented.

Production-Sharing Type Contracts

Our share of production and reserves from operations in the Wilmington field is subject to contractual arrangements similar to production-sharing contracts (PSCs) that are in effect through the economic life of the assets. Under such contracts we are obligated to fund all capital and operating costs. We record a share of production and reserves to recover a portion of such capital and operating costs and an additional share for profit. Our portion of the production represents volumes: (i) to recover our partners' share of capital and operating costs that we incur on their behalf, (ii) for our share of contractually defined base production and (iii) for our share of remaining production thereafter. We generate returns through our defined share of production from (ii) and (iii) above. These contracts do not transfer any right of ownership to us and reserves reported from these arrangements are based on our economic interest as defined in the contracts. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline, assuming comparable capital investment and operating costs. However, our net economic benefit is greater when product prices are higher. These PSCs represented approximately 16% of our total production for the year ended December 31, 2022.

In line with industry practice for reporting PSCs, we report 100% of operating costs under such contracts in our consolidated statements of operations as opposed to reporting only our share of those costs. We report the proceeds from production designed to recover our partners' share of such costs (cost recovery) in our revenues. Our reported production volumes reflect only our share of the total volumes produced, including cost recovery, which is less than the total volumes produced under the PSCs. This difference in reporting full operating costs but only our net share of production equally inflates our revenue and operating costs per barrel and has no effect on our net results.

Pension and Postretirement Benefit Plans

All of our employees participate in postretirement benefit plans we sponsor. These plans are primarily funded as benefits are paid. In addition, a small number of our employees also participate in defined benefit pension plans sponsored by us. We recognize the net overfunded or underfunded amounts in the consolidated financial statements at each measurement date.

We determine our defined benefit pension and postretirement benefit plan obligations based on various assumptions and discount rates. The discount rate assumptions used are meant to reflect the interest rate at which the obligations could effectively be settled on the measurement date. We estimate the rate of return on assets with regard to current market factors but within the context of historical returns.

Pension plan assets are measured at fair value. Publicly registered mutual funds are valued using quoted market prices in active markets. Commingled funds are valued at the fund units' net asset value (NAV) provided by the issuer, which represents the quoted price in a non-active market. Guaranteed deposit accounts are valued at the book value provided by the issuer.

Actuarial gains and losses that have not yet been recognized through income, are recorded in accumulated other comprehensive income within equity, net of taxes, until they are amortized as a component of net periodic benefit cost.

Leases

We account for our leases in which we are the lessee, other than mineral leases including oil and natural gas leases, under an accounting standard which requires us to recognize most leases, including operating leases, on the balance sheet. The majority of our leases are for commercial office space, fleet vehicles, drilling rigs, easements and facilities. We categorize leases as either operating or financing at lease commencement. We recognize a right-of-use (ROU) asset and associated lease liability for each operating and finance lease with contractual terms of greater than 12 months on the balance sheet. In considering whether a contract contains a lease, we first consider whether there is an identifiable asset and then consider how and for what purpose the asset would be used over the contract term. Our ROU assets are measured at the initial amount of the lease liability determined by measuring the present value of the fixed minimum lease payments, adjusted for any payments made before or at the lease commencement date, discounted using our incremental borrowing rate (IBR). In determining our IBR, we consider the average cost of borrowing for publicly traded corporate bond yields, which are adjusted to reflect our credit rating, the remaining lease term for each class of our leases and frequency of payments.

The ROU assets for operating leases are amortized over the term of the lease using the straight-line method. Lease expense also includes accretion of the lease liability recognized using the effective interest method. ROU assets are tested for impairment in the same manner as long-lived assets.

Share Repurchase Program

We repurchase shares of our common stock from time to time under a program authorized by our Board of Directors, including pursuant to a contract, instruction or written plan meeting requirements of Rule 10b5-1(c)(1) of the Exchange Act. Share repurchases have not been retired and are displayed separately as treasury stock on our consolidated balance sheet.

Assets Held for Sale

We may market certain non-core oil and natural gas assets or other properties for sale. At the end of each reporting period, we evaluate if these assets should be classified as held for sale. The held for sale criteria includes the following: management commitment to a plan to sell, the asset is available for immediate sale, an active program to locate a buyer exists, the sale of the asset is probable and expected to be completed within one year, the asset is being actively marketed for sale and it is unlikely that significant changes will be made to the plan. If all of these criteria are met, the asset is presented as held for sale on our consolidated balance sheet and measured at the lower of the carrying amount or estimated fair vale less costs to sell. DD&A expense is not recorded on assets once classified as held for sale.

The assets classified as held for sale at December 31, 2022 include the remaining assets and the associated asset retirement obligations in the Ventura basin. See *Note 3 Divestitures and Acquisitions* for more information.

Other Current Assets

Other current assets, net consisted of the following:

	December 31, 2022	December 31, 2021
	(in millions)	
Net amounts due from joint interest partners[(a)]	$ 39	$ 47
Fair value of derivative contracts	39	6
Prepaid expenses	17	16
Greenhouse gas allowances[(b)]	—	31
Natural gas margin deposits	16	12
Income tax receivable	10	—
Other	12	9
Other current assets, net	$ 133	$ 121

(a) Included in the 2022 net amounts due from joint interest partners are allowances of $1 million.
(b) Greenhouse gas allowances were higher at December 31, 2021 compared to 2022 due to the timing of the allowance purchases.

Other Noncurrent Assets

Other noncurrent assets consisted of the following:

	December 31, 2022	December 31, 2021
	(in millions)	
Operating lease right-of-use assets	$ 73	$ 43
Deferred financing costs - Revolving Credit Facility	6	11
Emission reduction credits	11	11
Prepaid power plant maintenance	28	21
Fair value of derivative contracts	7	1
Deposits and other	15	11
Other noncurrent assets	$ 140	$ 98

Accrued Liabilities

Accrued liabilities consisted of the following:

	December 31, 2022	December 31, 2021
	(in millions)	
Accrued employee-related costs	$ 49	$ 61
Accrued taxes other than on income	32	30
Asset retirement obligations	59	51
Accrued interest	19	19
Operating lease liability	18	11
Premiums due on derivative contracts	58	57
Liability for settlement payments due on derivative contracts	33	25
Other	30	43
Accrued liabilities	$ 298	$ 297

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	December 31, 2022	December 31, 2021
	(in millions)	
Compensation-related liabilities	$ 36	$ 38
Postretirement and pension benefit plans	33	59
Operating lease liability	52	37
Premiums due on derivative contracts	8	5
Contingent liability related to Carbon TerraVault JV put and call rights	48	—
Other	8	6
Other long-term liabilities	$ 185	$ 145

Reorganization Items, net

Reorganization items, net consisted of the following:

	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
(in millions)				
Gain on settlement of liabilities subject to compromise	$ —	$ —	$ —	$ 4,022
Unamortized deferred gain and issuance costs, net	—	—	—	125
Junior debtor-in-possession exit fee	—	—	—	(12)
Acceleration of unrecognized compensation expense on cancelled stock-based compensation awards	—	—	—	(5)
Write-off of prepaid directors and officers' insurance premiums	—	—	—	(2)
Total non-cash reorganization items	$ —	$ —	$ —	$ 4,128
Legal, professional and other, net	—	(6)	(3)	(43)
Debtor-in-possession financing costs	—	—	—	(25)
Total reorganization items, net	$ —	$ (6)	$ (3)	$ 4,060

Supplemental Cash Flow Information

Supplemental disclosures to our consolidated statements of cash flows, excluding leases and ARO, are presented below:

	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
(in millions)				
Supplemental Cash Flow Information				
Interest paid, net of amount capitalized	$ (43)	$ (28)	$ (8)	$ (79)
Income tax paid	$ 20	$ —	$ —	$ —
Supplemental Disclosure of Noncash Investing and Financing Activities				
Successor common stock, Subscription Rights and Warrants issued pursuant to the Plan	$ —	$ —	$ —	$ (494)
Successor common stock issued for the junior debtor-in-possession exit fee pursuant to the Plan	$ —	$ —	$ —	$ (12)
Successor common stock and EHP Notes issued for acquisition of noncontrolling interest pursuant to the Plan	$ —	$ —	$ —	$ (561)
Successor common stock issued for a backstop commitment premium pursuant to the Plan	$ —	$ —	$ —	$ (52)
Derivative related to additional earn-out consideration for the Ventura divestiture	$ —	$ 3	$ —	$ —
Receivable from affiliate	$ 32	$ —	$ —	$ —
Dividends accrued for stock-based compensation awards	$ 2	$ —	$ —	$ —
Contribution to the Carbon TerraVault JV	$ 2	$ —	$ —	$ —

NOTE 2 PROPERTY, PLANT AND EQUIPMENT

We capitalize the costs incurred to acquire or develop our oil and natural gas assets, including ARO and interest. For asset acquisitions, purchase price, including liabilities assumed, is allocated to acquired assets based on relative fair values at the acquisition date. We evaluate long-lived assets on a quarterly basis for possible impairment.

Property, plant and equipment, net consisted of the following:

	December 31, 2022	December 31, 2021
	(in millions)	
Proved oil and natural gas properties	$ 2,972	$ 2,604
Unproved oil and natural gas properties	2	1
Facilities and other	254	240
Total property, plant and equipment	3,228	2,845
Accumulated depreciation, depletion and amortization	(442)	(246)
Total property, plant and equipment, net	$ 2,786	$ 2,599

The following table summarizes the activity of capitalized exploratory well costs:

	Successor			Predecessor
(in millions)	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
Beginning balance	$ 1	$ 3	$ 3	$ 7
Additions to capitalized exploratory well costs	—	—	—	—
Reclassification to property, plant and equipment	—	—	—	—
Charged to expense	—	(2)	—	(2)
Impact of fresh start accounting	—	—	—	(2)
Ending balance	$ 1	$ 1	$ 3	$ 3

There are not significant exploratory well costs in the periods presented that have been capitalized for a period greater than one year after the completion of drilling. Our capitalized exploratory well costs at December 31, 2022 are for permitted wells that we intend to drill.

Asset Impairments

We recognized an asset impairment of $2 million for the year ended December 31, 2022 related to a write-down of a commercial office building located in Bakersfield, California to fair value. Asset impairments were $28 million for the year ended December 31, 2021, including $25 million related to the write-down of the same commercial office building to fair value and a $3 million write-off of capitalized costs related to projects which were abandoned. We valued our commercial office building based on a market approach (using Level 3 inputs in the fair value hierarchy). The decline in commercial demand for office space of this size and type in that market at each assessment resulted in an impairment. In 2022, we sold our commercial office building for $13 million. See *Note 3 Divestitures and Acquisitions* for further information regarding the sale of CRC Plaza.

The following table presents a summary of our asset impairments during the Predecessor period of 2020 (in millions):

Proved oil and natural gas properties	$ 1,487
Unproved properties	228
Other	21
Total	$ 1,736

The impairment charge of $1,736 million during the period ended October 31, 2020 was due to the sharp drop in commodity prices as of our March 31, 2020 assessment date.

The fair values of our proved oil and natural gas properties were determined using discounted cash flow models incorporating a number of fair value inputs which are categorized as Level 3 on the fair value hierarchy. These inputs were based on management's expectations for the future considering the then-current environment and included index prices based on forward curves, pricing adjustments for differentials, estimates of future oil and natural gas production, estimated future operating costs and capital development plans based on the embedded price assumptions. We used a market-based weighted average cost of capital to discount the future net cash flows. The impairment charge on our proved oil and natural gas properties primarily related to a steamflood property located in the San Joaquin basin.

As of our March 31, 2020 assessment date, we determined our ability to develop our unproved properties, which primarily consisted of leases held by production in the San Joaquin basin, was constrained for the foreseeable future and we did not intend to develop them.

We did not record an impairment charge during the Successor period of 2020.

NOTE 3 DIVESTITURES AND ACQUISITIONS

Divestitures

<u>*Ventura Basin*</u>

During the second quarter of 2021, we entered into transactions to sell our Ventura basin assets. The transactions contemplate multiple closings that are subject to customary closing conditions. The closings that occurred in the second half of 2021 resulted in the divestiture of the vast majority of our Ventura basin assets. We recognized a gain of $120 million on the Ventura divestiture during the year ended December 31, 2021.

During the year ended December 31, 2022, we recognized a gain of $11 million related to the sale of certain Ventura basin assets. The closing of the sale of our remaining assets in the Ventura basin is subject to final approval from the State Lands Commission, which we expect to receive in the first half of 2023. These remaining assets, consisting of property, plant and equipment and associated asset retirement obligations, are classified as held for sale on our consolidated balance sheet as of December 31, 2022.

<u>*Lost Hills*</u>

On February 1, 2022, we sold our 50% non-operated working interest in certain horizons within our Lost Hills field, located in the San Joaquin basin, recognizing a gain of $49 million. We retained an option to capture, transport and store 100% of the CO_2 from steam generators across the Lost Hills field for future carbon management projects. We also retained 100% of the deep rights and related seismic data.

<u>*CRC Plaza*</u>

In June 2022, we sold our commercial office building located in Bakersfield, California for net proceeds of $13 million, recognizing no gain or loss on sale. We also leased back a portion of the building with a term of 18 months. See *Note 2 Property, Plant and Equipment* for details of impairment charges we recognized prior to the sale of this property.

Other Divestitures

In 2022, we sold non-core assets recognizing a $1 million loss.

In 2021, we also sold unimproved land and other non-core assets for $13 million in proceeds recognizing a $4 million gain.

In January 2020, we sold royalty interests and divested non-core assets resulting in $41 million of proceeds which was treated as a normal retirement and no gain or loss was recognized.

Acquisitions

MIRA JV

Our development joint venture with Macquarie Infrastructure and Real Assets Inc. (MIRA JV) contemplated that MIRA would fund the development of certain of our oil and natural gas properties in exchange for a 90% working interest. In August 2021, we purchased MIRA's entire working interest share for $52 million. We accounted for this transaction as an asset acquisition. Prior to the acquisition, our consolidated results reflect only our 10% working interest share in the productive wells.

Other Acquisitions

In 2022, we acquired properties for carbon management activities for approximately $17 million.

NOTE 4 DEBT

As of December 31, 2022 and 2021, our long-term debt consisted of the following:

	Successor		Interest Rate	Maturity
	2022	2021		
	(in millions)			
Revolving Credit Facility	$ —	$ —	SOFR plus 3%-4% ABR plus 2%-3%	April 29, 2024
Senior Notes	600	600	7.125%	February 1, 2026
Principal amount of debt	$ 600	$ 600		
Unamortized debt issuance costs	(8)	(11)		
Long-term debt, net	$ 592	$ 589		

Fair Value

The estimated fair value of our debt at December 31, 2022 and 2021 was approximately $574 million and $623 million, respectively. We estimate the fair value of our fixed-rate debt based on prices from known market transactions as of December 31, 2022 and 2021 (Level 1 inputs on the fair value hierarchy).

Revolving Credit Facility

On October 27, 2020, we entered into a Credit Agreement with Citibank, N.A., as administrative agent, and certain other lenders. This credit agreement consists of a senior revolving loan facility (Revolving Credit Facility) with an aggregate commitment of $602 million, which we are permitted to increase if we obtain additional commitments from new or existing lenders. The aggregate commitment increased from $492 million as of December 31, 2021 due to $110 million of additional commitments from new lenders that joined this facility in 2022. Our Revolving Credit Facility also includes a sub-limit of $200 million for the issuance of letters of credit. As of December 31, 2022, we had approximately $458 million available for borrowing under the Revolving Credit Facility after taking into account $144 million of outstanding letters of credit.

The proceeds of all or a portion of the Revolving Credit Facility may be used for our working capital needs and for other purposes subject to meeting certain criteria.

Security – The lenders have a first-priority lien on a substantial majority of our assets.

Interest Rate – In February 2022, we amended our Revolving Credit Facility to change the benchmark rate from the London Interbank Offered Rate to the secured overnight financing rate (SOFR). We can elect to borrow at either an adjusted SOFR rate or an alternate base rate (ABR), subject to a 1% floor and 2% floor, respectively, plus an applicable margin. The ABR is equal to the highest of (i) the federal funds effective rate plus 0.50%, (ii) the administrative agent prime rate and (iii) the one-month SOFR rate plus 1%. The applicable margin is adjusted based on the borrowing base utilization percentage and will vary from (i) in the case of SOFR loans, 3% to 4% and (ii) in the case of ABR loans, 2% to 3%. The unused portion of the facility is subject to a commitment fee of 0.50% per annum. We also pay customary fees and expenses. Interest on ABR loans is payable quarterly in arrears. Interest on SOFR loans is payable at the end of each SOFR period, but not less than quarterly.

Amortization Payments – The Revolving Credit Facility does not include any obligation to make amortizing payments.

Borrowing Base – The borrowing base, currently $1.2 billion, will be redetermined semi-annually each April and October.

Financial Covenants – Our Revolving Credit Facility includes the following financial covenants:

Ratio	Components	Required Levels	Tested
Consolidated Total Net Leverage Ratio	Ratio of Consolidated Total Debt to Consolidated EBITDAX[(a)]	Not greater than 3.00 to 1.00	Quarterly
Current Ratio	Ratio of consolidated current assets to consolidated current liabilities[(b)]	Not less than 1.00 to 1.00	Quarterly

(a) EBITDAX is calculated as defined in the credit agreement.

(b) The available credit under our Revolving Credit Facility is included in consolidated current assets as part of the calculation of the current ratio.

Other Covenants – Our Revolving Credit Facility includes covenants that, among other things, restrict our ability to incur additional indebtedness, grant liens, make asset sales and investments, repay existing indebtedness, make subsidiary distributions and enter into transactions that would result in fundamental changes. We are also restricted in the amount of cash dividends we can pay on our common stock unless we meet certain covenants included in the credit agreement.

In April 2022, we amended our Revolving Credit Facility to, among other things, modify the minimum hedge requirement and the restricted payment and investment covenants contained in the Revolving Credit Facility. As a result of this amendment, the rolling hedge requirement has been modified. As amended, our Revolving Credit Facility requires us to maintain hedges on a minimum amount of crude oil production (determined on (i) the date of delivery of annual and quarterly financial statements and (ii) the date of delivery of a reserve report delivered in connection with an interim borrowing base redetermination) of no less than (i) in the event that our Consolidated Total Net Leverage Ratio (as defined in the Credit Agreement) is greater than 2:1 as of the end of the most recent fiscal quarter test period, 50% of our reasonably anticipated oil production from our proved developed producing reserves for each quarter during the period ending the earlier of (1) the maturity date of the Revolving Credit Facility and (2) 12 months after the delivery of the compliance certificate for the relevant test period and (ii) in the event that our Consolidated Total Net Leverage Ratio is less than or equal to 2:1 but greater than 1:1 as of the end of the most recent fiscal quarter test period, 33% of our reasonably anticipated oil production from our proved developed producing reserves for each quarter during the period ending the earlier of (1) the maturity date of the Revolving Credit Facility and (2) 12 months after the delivery of the compliance certificate for the relevant test period. The foregoing minimum hedge requirements do not apply to the extent that our Consolidated Total Net Leverage Ratio is less than or equal to 1:1 as of the last day of the most recently ended fiscal quarter test period.

Furthermore, the restricted payment and investments covenants were modified to permit unlimited investments and/or restricted payments so long as (i) no Default, Event of Default or Borrowing Base Deficiency shall have occurred and be continuing under the Revolving Credit Facility at the time of such investment or restricted payment, (ii) the undrawn availability under the Revolving Credit Facility at such time is not less than 30.0% of the total commitment and (iii) the Consolidated Total Net Leverage Ratio is less than or equal to 1.5:1.

Events of Default and Change of Control – Our Revolving Credit Facility provides for certain events of default, including upon a change of control, as defined in the credit agreement, that entitles our lenders to declare the outstanding loans immediately due and payable, subject to certain limitations and conditions.

Senior Notes

On January 20, 2021, we completed an offering of $600 million in aggregate principal amount of our 7.125% senior unsecured notes due 2026 (Senior Notes). The net proceeds of $587 million, after $13 million of debt issuance costs, were used to repay in full our Second Lien Term Loan and EHP Notes, with the remainder used to repay substantially all of the then outstanding borrowings under our Revolving Credit Facility. We recognized a $2 million loss on extinguishment of debt, including unamortized debt issuance costs, associated with these repayments.

Security – Our Senior Notes are general unsecured obligations which are guaranteed on a senior unsecured basis by certain of our material subsidiaries.

Redemption – On or after February 1, 2023, we may redeem the Senior Notes at any time prior to the maturity date at a redemption price equal to (i) 104% of the principal amount if redeemed in the twelve months beginning February 1, 2023, (ii) 102% of the principal amount if redeemed in the twelve months beginning February 1, 2024 and (iii) 100% of the principal amount if redeemed after February 1, 2025, in each case plus accrued and unpaid interest.

Other Covenants – Our Senior Notes include covenants that, among other things, restrict our ability to incur additional indebtedness, issue preferred stock, grant liens, make asset sales and investments, repay existing indebtedness, make subsidiary distributions and enter into transactions that would result in fundamental changes.

Events of Default and Change of Control – Our Senior Notes provide for certain triggering events, including upon a change of control, as defined in the indenture, that would require us to repurchase all or any part of the Senior Notes at a price equal to 101% of the aggregate principal amount plus accrued and unpaid interest.

Second Lien Term Loan

On October 27, 2020, we entered into a $200 million credit agreement with Alter Domus Products Corp., as administrative agent, and certain other lenders (Second Lien Term Loan). The proceeds were used to refinance our Junior DIP Facility and to pay certain costs, fees and expenses related to the other transactions consummated on the Effective Date.

Security – The lenders had a second-priority lien (junior to the Revolving Credit Facility) on a substantial majority of our assets, except assets securing the EHP Notes as discussed below.

Interest Rate – We could elect to pay interest at either an adjusted LIBOR rate or ABR rate, subject to a 1% floor and 2% floor, respectively, plus an applicable margin. The ABR rate was equal to the highest of (i) the prime rate, (ii) the federal funds rate effective rate plus 0.50%, and (iii) the one-month adjusted LIBOR rate plus 1%. Prior to the second anniversary of the closing date of the Second Lien Term Loan, the applicable margin in the case of an ABR rate election was 8% per annum if paid in cash and 9.50% per annum if paid-in-kind, and the applicable margin in the case of an adjusted LIBOR rate election was 9% if paid in cash and 10.50% if paid-in-kind. After the second anniversary of the closing date, the applicable margin was 8% with respect to any ABR loan and 9% with respect to an adjusted LIBOR loan. Interest on ABR loans was paid quarterly in arrears and interest based on the adjusted LIBOR rate was due at the end of each LIBOR period, which could be one, two, three or six months but not less than quarterly. We also paid customary fees and expenses.

Maturity Date – Our Second Lien Term Loan would mature five years after the closing date, subject to extension.

Redemption – We could elect to redeem all or part of our Second Lien Term Loan, at any time prior to the maturity date, at redemption price equal to (i) 100% of the principal amount if redeemed prior to 90 days after closing, (ii) 105% of the principal amount if redeemed after 90 days and before the first anniversary date, (iii) 103% of the principal amount if redeemed on or after the first anniversary date and before the second anniversary date, (iv) 102% of the principal amount if redeemed on or after the second anniversary date and before the third anniversary date, (v) 101% of the principal amount if redeemed on or after the third anniversary date and before the fourth anniversary date, and (vi) at 100% of the principal amount if redeemed in the fifth year.

Financial Covenants – Our Second Lien Term Loan included certain financial covenants that were to be tested quarterly, including a consolidated total net leverage ratio and current ratio.

Liquidity – We would become subject to a monthly minimum liquidity requirement of $170 million if, as of the Spring 2021 Scheduled Redetermination (as defined in the Revolving Credit Facility), (a) our liquidity was less than $247 million and (b) we were not able to obtain at least $51 million in additional commitments under our Revolving Credit Facility or through capital markets or other junior financing transactions, for so long as the conditions in (a) and (b) remained unmet.

Other Covenants – Our Second Lien Term Loan included covenants that, among other things, restricted our ability to incur additional indebtedness, grant liens, make asset sales and investments, repay existing indebtedness, make subsidiary distributions and enter into transactions that would result in fundamental changes. We were also restricted in the amount of cash dividends we could pay on our common stock unless we met certain covenants included in the credit agreement.

Our Second Lien Term Loan also required us to maintain hedges on a minimum amount of crude oil production on terms that were substantially consistent with the requirements of our Revolving Credit facility.

Events of Default and Change of Control – Our Second Lien Term Loan provided for certain events of default, including upon a change of control, as defined in the credit agreement, that would entitle our lenders to declare the outstanding loans immediately due and payable, subject to certain limitations and conditions. We were subject to a cross-default provision that causes a default under this facility if certain defaults occurred under the Revolving Credit Facility or the EHP Notes.

The Second Lien Term Loan was terminated and repaid with proceeds from our Senior Notes offering in January 2021 as described above.

EHP Notes

On the Effective Date, our wholly-owned subsidiary, EHP Midco Holding Company, LLC (Elk Hills Issuer) entered into a Note Purchase Agreement (Note Purchase Agreement) with certain subsidiaries of Ares and Wilmington Trust, N.A. as collateral agent. The $300 million Notes were issued as partial consideration for the Class B Preferred Units, Class A Common Units and Class C Common Units in the Ares JV previously held by ECR (EHP Notes).

The EHP Notes were senior notes due in 2027 and were secured by a first-priority security interest in all of the assets of Elk Hills Power, any third-party offtake contracts for power generated by Elk Hills Power, all of the equity interests of Elk Hills Power held by Elk Hills Issuer and all of the equity interests of Elk Hills Issuer held by its direct parent, EHP Topco Holding Company, LLC, our wholly-owned subsidiary. We and Elk Hills Power guaranteed, on a joint and several basis, all of the obligations of Elk Hills Issuer under the EHP Notes. The EHP Notes bore an interest rate of 6.0% per annum through the fourth anniversary of issuance, increasing to 7.0% per annum after the fourth anniversary of issuance and to 8.0% per annum after the fifth anniversary of issuance. We were permitted to redeem the EHP Notes at any time prior to their maturity date without payment of premium or penalty.

The EHP Notes were terminated and repaid with proceeds from our Senior Notes offering in January 2021 as described above.

Other

At December 31, 2022, all obligations under our Revolving Credit Facility and Senior Notes are guaranteed by certain of our material wholly owned subsidiaries.

The terms and conditions of all of our indebtedness are subject to additional qualifications and limitations that are set forth in the relevant governing documents.

At December 31, 2022, we were in compliance with all debt covenants under our credit agreements.

Principal maturities of debt outstanding at December 31, 2022 are as follows:

	As of December 31, 2022
	(in millions)
2023	$ —
2024	—
2025	—
2026	600
2027	—
Thereafter	—
Total	$ 600

NOTE 5 LEASES

Balance sheet information related to our operating leases as of December 31, 2022 and 2021 were as follows:

	Classification	2022	2021
		(in millions)	
Right-of-use assets	*Other noncurrent assets*	$ 73	$ 43
Operating lease liabilities	*Accrued liabilities*	$ 18	$ 11
Operating lease liabilities	*Other long-term liabilities*	52	37

We determine if our arrangements contain a lease at inception. A lease is defined as a contract, or part of a contract, that conveys the right to control the use of identified property, plant or equipment for a period of time in exchange for consideration. We have operating lease liabilities for carbon sequestration easements, drilling rigs, vehicles and commercial office space.

We combine lease and nonlease components in determining fixed minimum lease payments for our drilling rigs and commercial office space. If applicable, fixed minimum lease payments are reduced by lease incentives for our commercial buildings and increased by mobilization and demobilization fees for our drilling rigs. Certain of our lease agreements include options to extend or terminate the lease, which we exercise at our sole discretion. For our existing leases, we did not include these options in determining our fixed minimum lease payments over the lease term. Our leases do not include options to purchase the leased property. Lease agreements for our fleet vehicles include residual value guarantees, none of which are recognized in our financial statements until the underlying contingency is resolved.

Variable lease costs for our drilling rigs include costs to operate, move and repair the rigs. Variable lease costs for certain of our commercial office buildings included utilities and common area maintenance charges. Variable lease costs for our fleet vehicles include other-than-routine maintenance and other various amounts in excess of our fixed minimum rental fee.

Our lease costs, including amounts capitalized to PP&E, shown in the table below are before joint-interest recoveries. Lease payments are reduced by joint interest recoveries on our consolidated statement of operations through our joint-interest billing process.

	Year ended December 31, 2022	Year ended December 31, 2021
	(in millions)	
Operating lease costs	$ 17	$ 14
Short-term lease costs[(a)]	59	48
Variable lease costs	6	4
Total operating lease costs	82	66
Sublease income	(1)	(2)
Total lease costs	$ 81	$ 64

(a) Contracts with terms of less than one month or less are excluded from our disclosure of short-term lease costs.

We had two contracts treated as finance leases, where the terms ended in 2022. These leases were not material to our consolidated results of operations for the periods presented.

We sublease certain commercial office space to third parties where we are the primary obligor under the head lease. The lease terms on those subleases never extend past the term of the head lease and the subleases contain no extension options or residual value guarantees. Sublease income is recognized based on the contract terms and included as a reduction of operating lease cost under our head lease. We sold our commercial office space during 2022. Sublease income was not material to our consolidated financial statements for all periods presented.

Other supplemental information related to our operating and finance leases as of December 31, 2022 and 2021 is provided below:

	Year ended December 31, 2022	Year ended December 31, 2021
	(in millions)	
Cash paid for lease liabilities		
Lease liabilities associated with operating activities	$ 14	$ 8
Lease liabilities associated with investing activities	$ 6	$ 4
Lease liabilities associated with financing activities	$ —	$ 1
ROU assets obtained in exchange for new operating lease liabilities	$ 35	$ 17

	2022	2021
Operating Leases		
Weighted-average remaining lease term (in years)	6.43	8.25
Weighted-average discount rate	6.1 %	5.4 %
Finance Leases		
Weighted-average remaining lease term (in years)	—	0.33
Weighted-average discount rate	— %	4.0 %

The difference in the weighted-average discount rate between operating leases and finance leases in 2021 primarily relates to lease term.

Our operating lease payments are as follows:

	As of December 31, 2022
	(in millions)
2023	$ 21
2024	15
2025	12
2026	12
2027	5
Thereafter	20
Less: Interest	(15)
Present value of lease liabilities	$ 70

NOTE 6 LAWSUITS, CLAIMS, COMMITMENTS AND CONTINGENCIES

We, or certain of our subsidiaries, are involved, in the normal course of business, in lawsuits, environmental and other claims and other contingencies that seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2022 and 2021 were not material to our consolidated balance sheets as of such dates. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves cannot be accurately determined.

In October 2020, Signal Hill Services, Inc. defaulted on its decommissioning obligations associated with two offshore platforms. The Bureau of Safety and Environmental Enforcement (BSEE) determined that former lessees, including our former parent, Occidental Petroleum Corporation (Oxy) with a 37.5% share, are responsible for accrued decommissioning obligations associated with these offshore platforms. Oxy sold its interest in the platforms approximately 30 years ago and it is our understanding that Oxy has not had any connection to the operations since that time and challenged BSEE's order. Oxy notified us of the claim under the indemnification provisions of the Separation and Distribution Agreement between us and Oxy. In September 2021, we accepted the indemnification claim from Oxy and we are now appealing the order from BSEE.

We have certain commitments under contracts, including purchase commitments for goods and services used in the normal course of business such as pipeline capacity, easements related to oil and natural gas operations, obligations under long-term service agreements and field equipment.

At December 31, 2022, total purchase obligations on a discounted basis were as follows:

	December 31, 2022
	(in millions)
2023	$ 61
2024	9
2025	6
2026	6
2027	5
Thereafter	25
Total	112
Less: Interest	(19)
Present value of purchase obligations	$ 93

NOTE 7 DERIVATIVES

We continue to maintain a commodity hedging program primarily focused on crude oil to help protect our cash flows, margins and capital program from the volatility of commodity prices. We did not have any commodity derivatives designated as accounting hedges as of and during the years ended December 31, 2022, 2021 and each of the periods in 2020. Unless otherwise indicated, we use the term "hedge" to describe derivative instruments that are designed to achieve our hedging requirements and program goals, even though they are not accounted for as accounting hedges. Our Revolving Credit Facility includes covenants that require us to maintain a certain level of hedges. We have also entered into incremental hedges above and beyond these requirements and will continue to evaluate our hedging strategy based on prevailing market prices and conditions. For more information on the requirements of our Revolving Credit Facility, see *Note 4 Debt.*

Commodity-Price Risk

As part of our hedging program, we held the following Brent-based crude oil contracts as of December 31, 2022:

	Q1 2023	Q2 2023	Q3 2023	Q4 2023	2024
Sold Calls:					
Barrels per day	18,322	17,837	17,363	5,747	—
Weighted-average price per barrel	$ 57.28	$ 60.00	$ 57.06	$ 57.06	$ —
Swaps					
Barrels per day	16,620	16,475	16,697	26,094	1,492
Weighted-average price per barrel	$ 69.46	$ 68.53	$ 68.33	$ 70.18	$79.06
Net Purchased Puts(a)					
Barrels per day	18,322	17,837	17,363	5,747	1,724
Weighted-average price per barrel	$ 76.25	$ 76.25	$ 76.25	$ 76.25	$75.00

(a) Purchased puts and sold puts with the same strike price have been presented on a net basis.

The outcomes of the derivative positions are as follows:

- Sold calls – we make settlement payments for prices above the indicated weighted-average price per barrel.
- Net purchased puts – we receive settlement payments for prices below the indicated weighted-average price per barrel.
- Swaps – we make settlement payments for prices above the indicated weighted-average price per barrel and receive settlement payments for prices below the indicated weighted-average price per barrel.

We use combinations of these positions to meet the requirements of our Revolving Credit Facility and to increase the efficacy of our hedging program. At December 31, 2022, we had derivative contracts for an insignificant amount of natural gas volumes.

Derivative instruments not designated as hedging instruments are required to be recorded on the balance sheet at fair value. Noncash derivative gains and losses, along with settlement payments, are reported in net (loss) gain from commodity derivatives on our consolidated statements of operations as shown in the table below:

	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
(in millions)				
Non-cash commodity derivative gain (loss), excluding noncontrolling interest	$ 187	$ (357)	$ (138)	$ (19)
Non-cash commodity derivative (loss) gain, attributable to noncontrolling interest	—	—	(2)	2
Total non-cash changes	187	(357)	(140)	(17)
Net (payments) proceeds on commodity derivatives	(738)	(319)	(1)	108
Net (loss) gain from commodity derivatives	$ (551)	$ (676)	$ (141)	$ 91

Interest-Rate Risk

As of December 31, 2022, we do not have any derivative contracts in place with respect to interest-rate exposure. In May 2018, we entered into derivative contracts that limited our interest rate exposure with respect to a notional amount of $1.3 billion of variable-rate indebtedness. These contracts expired on May 4, 2021. We did not report any gains or losses on these contracts and no settlement payments were received during the year ended December 31, 2021 or the periods in 2020.

Fair Value of Derivatives

Our derivative contracts are measured at fair value using industry-standard models with various inputs, including quoted forward prices, and are classified as Level 2 in the required fair value hierarchy for the periods presented.

The following tables present the fair values (at gross and net) of our outstanding commodity derivatives:

December 31, 2022			
Classification	Gross Amounts at Fair Value	Netting	Net Fair Value
		(in millions)	
Assets:			
Other current assets	$ 51	$ (12)	$ 39
Other noncurrent assets	7	—	7
Liabilities:			
Current - Fair value of derivative contracts	(258)	12	(246)
Noncurrent - Fair value of derivative contracts	—	—	—
	$ (200)	$ —	$ (200)

December 31, 2021			
Classification	Gross Amounts at Fair Value	Netting	Net Fair Value
		(in millions)	
Assets:			
Other current assets	$ 33	$ (27)	$ 6
Other noncurrent assets	12	(11)	1
Liabilities:			
Current - Fair value of derivative contracts	(297)	27	(270)
Noncurrent - Fair value of derivative contracts	(143)	11	(132)
	$ (395)	$ —	$ (395)

Counterparty Credit Risk

As of December 31, 2022, all of our derivative financial instruments were with investment-grade counterparties. We actively evaluate the creditworthiness of our counterparties, assign credit limits and monitor exposure against those assigned limits. We believe exposure to credit-related losses as of December 31, 2022 was not significant. Losses associated with credit risk have been insignificant for all periods presented. At December 31, 2022, and 2021, we had an insignificant amount of collateral posted.

NOTE 8 INVESTMENT IN UNCONSOLIDATED SUBSIDIARY AND RELATED PARTY TRANSACTIONS

In August 2022, our wholly-owned subsidiary Carbon TerraVault I, LLC entered into a joint venture with BGTF Sierra Aggregator LLC (Brookfield) for the further development of a carbon management business in California (Carbon TerraVault JV). We hold a 51% interest in the Carbon TerraVault JV and Brookfield holds a 49% interest. We determined that the Carbon TerraVault JV is a VIE; however, we share decision-making power with Brookfield on all matters that most significantly impact the economic performance of the joint venture. Therefore, we account for our investment in the Carbon TerraVault JV under the equity method of accounting. See *Note 1 Nature of Business, Summary of Significant Accounting Policies and Other* for more information on the VIE consolidation model.

Brookfield has committed an initial $500 million to invest in CCS projects that are jointly approved through the Carbon TerraVault JV. As part of the formation of the Carbon TerraVault JV, we contributed rights to inject CO_2 into the 26R reservoir in our Elk Hills field for permanent CO_2 storage (26R reservoir) and Brookfield committed to make an initial investment of $137 million, payable in three equal installments with the last two installments subject to the achievement of certain milestones. Brookfield contributed the first $46 million installment of their initial investment to the Carbon TerraVault JV in 2022. This amount may, at our sole discretion, be distributed to us or used to satisfy our share of future capital contributions, among other items. During 2022, $12 million was distributed to us (and used to pay transaction costs related to the formation of the joint venture) and $2 million was used to satisfy a capital call. The remaining $32 million is included in receivable from affiliate on our consolidated balance sheet as of December 31, 2022. Because the parties have certain put and call rights (repurchase features) with respect to the 26R reservoir if certain milestones are not met, the initial investment by Brookfield is reflected as a contingent liability, included in other long-term liabilities, on our consolidated balance sheet. This contingent liability was $48 million as of December 31, 2022, including $2 million of interest, and reflects the amount we would be required to pay should Brookfield exercise its put right.

The carrying value of our investment in unconsolidated subsidiary was $13 million as of December 31, 2022. This carrying value reflects our investment less cumulative losses allocated to us of $1 million through December 31, 2022. The underlying net assets of the Carbon TerraVault JV were $314 million as of December 31, 2022 which includes cash on hand and PP&E, net of current liabilities. The difference between the carrying value of our investment and the carrying value of the underlying net assets of the joint venture relates to our accounting for the contribution of the 26R reservoir as a financing arrangement due to the put and call features of the joint venture. The joint venture recognized the cash contributions by the members and the 26R reservoir at fair value.

The Carbon TerraVault JV has an option to participate in certain projects that involve the capture, transportation and storage of CO_2 in California. This option expires upon the earlier of (1) August 2027, (2) when a final investment decision has been approved by the Carbon TerraVault JV for storage projects representing in excess of 5 million metric tons per annum (MMTPA) in the aggregate, or (3) when Brookfield has made contributions to the joint venture in excess of $500 million (unless Brookfield elects to increase its commitment).

We entered into a Management Services Agreement (MSA) with the Carbon TerraVault JV whereby we provide administrative, operational and commercial services under a cost-plus arrangement. Services may be supplemented by using third parties and payments to us under the MSA are limited to the amounts in an approved budget. The MSA may be terminated by mutual agreement of the parties, among other events. As of December 31, 2022, we had a $1 million receivable due to us under the MSA which is included in receivable from affiliate on our consolidated balance sheet.

NOTE 9 INCOME TAXES

Net income (loss) before income taxes, for all periods presented, was generated from domestic operations. We recognized an income tax provision (benefit) for the periods presented as follows:

	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
(in millions)				
Current				
Federal	$ 10	$ —	$ —	$ —
State	1	—	—	—
Subtotal	11	—	—	—
Deferred				
Federal	141	(161)	—	—
State	85	(235)	—	—
Subtotal	226	(396)	—	—
Total income tax provision (benefit)	$ 237	$ (396)	$ —	$ —

Total income tax provision (benefit) differs from the amounts computed by applying the U.S. federal income tax statutory rate to pre-tax income (loss) as follows:

	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
U.S. federal statutory tax rate	21 %	21 %	21 %	21 %
State income taxes, net	9	(81)	—	—
Exclusion of income attributable to noncontrolling interests	—	(1)	—	(1)
Debt restructuring	—	—	—	—
Changes in tax attributes	(2)	(8)	—	—
Executive compensation	—	2	—	—
Change in the U.S. federal valuation allowance	2	(106)	(20)	(21)
Other	1	—	(1)	1
Effective tax rate	31 %	(173) %	— %	— %

For the year ended December 31, 2022, our effective rate of 31% differed from the U.S. federal statutory tax rate of 21% primarily due to state taxes and the increase in a valuation allowance for a capital loss generated from the sale of Lost Hills. For the year ended December 31, 2021, our effective tax rate of negative 173% differed from the U.S. federal statutory tax rate of 21% primarily due to state taxes and releasing all of our valuation allowance recorded against our net deferred tax assets given our anticipated future earnings trends at that time. A portion of the change in our valuation allowance during 2021 was for the utilization of tax benefits against current year income and the remainder was recognized as a tax benefit reflecting the projected utilization of our deferred tax assets. We did not record an income tax provision (benefit) in the period ended December 31, 2020 or the period ended October 31, 2020.

The tax effects of temporary differences resulting in deferred income tax assets and liabilities at December 31, 2022 and 2021 were as follows:

	2022		2021	
	Deferred Tax Assets	Deferred Tax Liabilities	Deferred Tax Assets	Deferred Tax Liabilities
	(in millions)			
Property, plant and equipment	$ 47	$ (267)	$ 122	$ (151)
Postretirement and pension benefit plans	10	(1)	18	—
Asset retirement obligations	148	—	152	—
Net operating loss and tax credit carryforwards	85	—	88	—
Business interest expense carryforward	167	—	177	—
Federal benefit of state income taxes	—	(31)	—	(49)
Other	77	(36)	59	(20)
Subtotal	534	(335)	616	(220)
Valuation allowance	(35)	—	—	—
Total deferred taxes	$ 499	$ (335)	$ 616	$ (220)

Management expects to realize the recorded deferred tax assets primarily through future operating income and reversal of taxable temporary differences. We assess the realizability of our deferred tax assets each period by considering whether it is more-likely-than-not that all or a portion of our deferred tax assets will be realized. At each reporting date new evidence is considered, both positive and negative, including whether sufficient future taxable income will be generated to permit realization of existing deferred tax assets. The amount of deferred tax assets considered realizable is not assured and could be adjusted if estimates change or three-years of cumulative income is no longer present.

Carryforwards

As of December 31, 2022, we had U.S. federal net operating loss carryforwards of $29 million, which begin to expire in 2037. Our carryforward for disallowed business interest of $794 million does not expire.

As of December 31, 2022, we had California net operating loss carryforwards of $2.4 billion, which begin to expire in 2026, and $23 million of tax credit carryforwards, which begin to expire in 2041.

Our ability to utilize a portion of our net operating loss, tax credit and interest expense carryforwards is subject to an annual limitation since we experienced an ownership change in connection with our emergence from bankruptcy. We did not recognize a tax benefit for $18 million U.S. federal net operating loss carryforwards and approximately $2 billion California net operating loss carryforwards which we expect will expire unused. Additionally, we did not recognize a tax benefit for $14 million of California tax credit carryforwards which we expect will expire unused.

Unrecognized Tax Benefits

We did not record a liability for unrecognized tax benefits as of December 31, 2022 and 2021.

In the period ended October 31, 2020, we recognized a tax benefit of $101 million for uncertain tax positions which primarily related to the calculation of the limitation on business interest expense. In 2020, the Internal Revenue Service (IRS) issued final regulations which clarified the calculation of the limitation on the deduction of business interest expense. Based on our evaluation of these final regulations, we determined that our income tax returns were filed on at least a more-likely-than-not basis and accordingly we reversed our liability for uncertain tax positions.

We remain subject to audit by the Internal Revenue Service for calendar years 2019 through 2021 as well as 2018 through 2021 by the state of California.

NOTE 10 STOCK-BASED COMPENSATION

On January 18, 2021, our Board of Directors approved the California Resources Corporation 2021 Long Term Incentive Plan (Long Term Incentive Plan). The shares issuable under the new long-term incentive plan had been previously authorized by the Bankruptcy Court in connection with our emergence from Chapter 11 and the terms of the new long-term incentive plan were approved by our Board of Directors. As a result, the Long Term Incentive Plan became effective on January 18, 2021. The Long Term Incentive Plan provides for potential grants of stock options, stock appreciation rights, restricted stock awards, restricted stock units, vested stock awards, dividend equivalents, other stock-based awards and substitute awards to employees, officers, non-employee directors and other service providers of the Company and its affiliates. The Long Term Incentive Plan replaces the earlier Amended and Restated California Resources Corporation Long Term Incentive Plan which was cancelled upon our emergence from bankruptcy, along with all outstanding stock-based compensation awards granted thereunder.

The Long Term Incentive Plan provides for the reservation of 9,257,740 shares of common stock for future issuances, subject to adjustment as provided in the Long Term Incentive Plan. Shares of stock subject to an award under the Long Term Incentive Plan that expires or is cancelled, forfeited, exchanged, settled in cash or otherwise terminated without the actual delivery of shares (restricted stock awards are not considered “delivered shares” for this purpose) will again be available for new awards under the Long Term Incentive Plan. However, (i) shares tendered or withheld in payment of any exercise or purchase price of an award or taxes relating to awards, (ii) shares that were subject to an option or a stock appreciation right but were not issued or delivered as a result of the net settlement or net exercise of the option or stock appreciation right, and (iii) shares repurchased on the open market with the proceeds from the exercise price of an option, will not, in each case, again be available for new awards under the Long Term Incentive Plan.

Shares of our common stock may be withheld by us in satisfaction of tax withholding obligations arising upon the vesting of restricted stock units (RSUs) and performance stock units (PSUs).

Stock-based compensation expense is recorded on our consolidated statements of operations based on job function of the employees receiving the grants as shown in the table below.

	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
(in millions)				
General and administrative expenses	$ 26	$ 17	$ —	$ 2
Operating costs	4	2	—	1
Total stock-based compensation expense	$ 30	$ 19	$ —	$ 3
Income tax benefit	$ 6	$ —	$ —	$ —

We paid $6 million for our long-term cash incentive awards for the year ended December 31, 2022. We did not make any payments for the cash-settled portion of our awards for the year ended December 31, 2021 or in the Successor period of 2020. We made payments of $8 million for the cash-settled portion of our long-term incentive awards during the Predecessor period of 2020.

Successor Stock-Based Compensation Plan

Long-Term Stock Settled Awards

Restricted Stock Units

Executives and non-employee directors were granted RSUs, which are in the form of, or equivalent in value to, actual shares of our common stock. The awards generally vest ratably over three years, with one third of the granted units vesting on each of the first three anniversaries of the applicable date of grant. RSUs are settled in shares of our common stock at the end of the third year of the three-year vesting period.

The following table sets forth RSU activity for the year ended December 31, 2022:

	Number of Units		Weighted-Average Grant-Date Fair Value
	(in thousands)		
Unvested at December 31, 2021	1,130	$	25.28
Granted	20	$	44.31
Vested	—	$	—
Cancelled or Forfeited	(29)	$	24.78
Unvested at December 31, 2022	1,121	$	25.64

Compensation expense was measured on the date of grant using the quoted market price of our common stock and is primarily recognized on a straight-line basis over the requisite service periods adjusted for actual forfeitures, if any.

As of December 31, 2022, the unrecognized compensation expense for our unvested RSUs was approximately $10 million and is expected to be recognized over a weighted-average remaining service period of approximately one year.

Performance Stock Units

Executives were granted PSUs which are earned upon the attainment of specified 60-trading day volume weighted average prices for shares of our common stock generally during a three-year service period commencing on the grant date. Once units are earned, the earned units are not reduced for subsequent decreases in stock price. For the duration of the three-year period, a minimum of 0% and a maximum of 100% of the PSUs granted could be earned. The grant date fair value and associated equity compensation expense was measured using a Monte Carlo simulation model which runs a probabilistic assessment of the number of units that will be earned based on a projection of our stock price during the three-year service period. Although certain events may accelerate vesting, earned PSUs generally vest on the third anniversary of the grant date, and are settled in shares of our common stock at the three-year anniversary of the grant date. PSU grants made to certain executives in 2021 have been fully earned.

The following table sets forth PSU activity for the year ended December 31, 2022:

	Number of Units		Weighted-Average Grant-Date Fair Value
	(in thousands)		
Unvested at December 31, 2021	944	$	20.14
Granted	4	$	31.76
Cancelled or Forfeited	(1)	$	19.31
Unvested at December 31, 2022	947	$	20.19

The range of assumptions used in the valuation of PSUs granted during 2022 and 2021 were as follows:

	Successor	
	2022	2021
Expected volatility[(a)]	60.00%	60.00% - 65.00%
Risk-free interest rate[(b)]	1.59% - 2.55%	0.16% - 0.60%
Dividend yield[(c)]	— %	— %
Forecast period (in years)	2 - 3	2 - 3

(a) Expected volatility was calculated using the historic volatility of a peer group due to our limited trading history since our emergence from bankruptcy. For awards granted after June 2021, expected volatility included the historic volatility of our stock, excluding our first two trading months.
(b) Based on the U.S. Treasury yield for a two- or three-year term at the grant date.
(c) A dividend adjusted stock price (assumed reinvestment of dividends during the performance period) was used.

Compensation expense is recognized on a straight-line basis over the requisite service periods adjusted for actual forfeitures, if any. Events that accelerate the vesting of an award have no effect on the requisite service period until such an event becomes probable.

As of December 31, 2022, the unrecognized compensation expense for our unvested PSUs was approximately $7 million and is expected to be recognized over a weighted-average remaining service period of approximately one year.

Long-Term Cash Incentive Awards

On June 30, 2022 and 2021, we granted performance cash-settled awards to approximately 500 non-executive employees where half of the award is variable with payouts ranging from 75% to 150% of the grant value. The variable portion of the award is determined based upon the attainment of specified 60-trading day volume weighted average prices for shares of our common stock preceding each vesting date. These awards vest ratably over a three-year service period, with one third of the grants vesting on each of the first three anniversaries of the grant date. The fair value of the awards is adjusted on a quarterly basis for the cumulative change in the value determined using a Monte Carlo simulation model which runs a probabilistic assessment of our stock price for each of the three-year service periods.

The assumptions used in the valuation of our cash awards as of December 31, 2022 were as follows:

	2022 Awards	2021 Awards
Expected volatility[(a)]	55%	46%
Risk-free interest rate[(b)]	4.32%	4.57%
Dividend yield[(c)]	— %	— %
Forecast period (in years)	2.5	1.5

(a) Expected volatility for the 2022 awards was calculated using the historic volatility of a peer group which included our stock, excluding our first two trading months. Expected volatility for the 2021 awards was calculated using the historical volatility of our stock.
(b) Based on the U.S. Treasury yield for the 2.5 and 1.5 year remaining terms.
(c) A dividend adjusted stock price (assumed reinvestment of dividends during the performance period) was used.

As of December 31, 2022, the unrecognized compensation expense for all of our unvested cash-settled awards was $16 million and is expected to be recognized over a weighted-average remaining service period of approximately 2.3 years. The value of awards forfeited during the year ended December 31, 2022 was approximately $2 million.

Predecessor Stock-Based Compensation Plan

As a result of our bankruptcy as described in *Note 15 Chapter 11 Proceedings*, the outstanding stock-based awards granted under our Amended and Restated California Resources Corporation Long-Term Incentive Plan (Amended LTIP) were cancelled on our Effective Date.

In 2019, our stockholders approved the Amended LTIP, which provided for the issuance of stock, incentive and non-qualified stock options, restricted stock awards, restricted stock units, stock appreciation rights, stock bonuses, performance-based awards and other awards to executives, employees and non-employee directors. Shares of our common stock were permitted to be withheld by us in satisfaction of tax withholding obligations arising upon the exercise of stock options or the vesting of restricted stock units. Further, shares of our common stock were permitted to be withheld by us in payment of the exercise price of employee stock options, which also counted against the authorized shares specified above. The maximum number of authorized shares of our common stock that were available for issuance pursuant to the Amended LTIP was 7,275,000 shares.

In the second quarter of 2020, our then Board of Directors approved the following changes to awards previously granted during 2020: (i) the previously established target amounts under the 2020 variable compensation programs remained unchanged, but any unvested amounts under such programs were revised to only be eligible for cash settlement, and (ii) as a condition to receiving any award under our 2020 variable compensation programs, participants waived participation in our 2020 annual incentive program and forfeited all stock-based compensation awards previously granted in 2020. At the time of the amendments, there were no changes to any stock-based compensation awards granted prior to February 2020; however, as a result of our bankruptcy, the outstanding stock-based awards under our Amended LTIP were cancelled on our Effective Date.

The cancellation of the stock-based compensation awards granted under the Amended LTIP prior to 2020 resulted in the recognition of all previously unrecognized compensation expense for equity-based awards under the Amended LTIP and the elimination of the liability related to cash-based awards under the Amended LTIP.

Restricted Stock Units

As part of the Amended LTIP, executives and other employees were granted restricted stock units (RSUs). RSUs were service based and, depending on the terms of the awards, were settled in cash or stock at the time of vesting. The awards either (i) vested ratably over three years, with one third of the granted units becoming vested on the day before each of the first three anniversaries of the applicable date of grant, or (ii) cliff vested upon the third anniversary of the applicable date of grant. Our RSUs had nonforfeitable dividend rights, and any dividends or dividend equivalents declared during the vesting period were paid as declared.

For cash- and stock-settled RSUs, compensation value was initially measured on the date of grant using the quoted market price of our common stock. Compensation expense for cash-settled RSUs was adjusted on a monthly basis for the cumulative change in the value of the underlying stock. For the Predecessor period of 2020, the weighted-average fair value of each stock-settled RSU granted was $6.20. Compensation expense for the stock-settled RSUs were recognized on a straight-line basis over the requisite service periods, adjusted for actual forfeitures. All outstanding RSUs were cancelled for no consideration as a result of our emergence from bankruptcy.

Performance Stock Units

Our performance stock units (PSUs) were restricted stock unit awards with performance targets with payouts ranging from 0% to 200% of the target award. Up to the target amount of the PSUs were eligible to be settled in cash or stock, and any amount of the PSUs earned in excess of the target amounts of such PSUs were to be settled in cash. These awards accrued dividend equivalents as dividends are declared during the vesting period, which were paid upon certification for the number of earned PSUs. Compensation expense was adjusted quarterly, on a cumulative basis, for any changes in the number of share equivalents expected to be paid based on the relevant performance criteria. For the Predecessor period of 2020, the weighted-average fair value of each stock-settled PSU granted was $6.20. All outstanding PSUs were cancelled for no consideration as a result of our emergence from bankruptcy.

Stock Options

We granted stock options to certain executives under our Amended LTIP. These options permitted the purchase of Predecessor common stock at exercise prices no less than the fair market value of the stock on the date the options were granted, with the majority of options being granted at 10% above fair market value. The options had terms of seven years and vested ratably over three years, with one third of the granted options becoming exercisable on the day before each of the first three anniversaries of the applicable date of grant, subject to certain restrictions including continued employment. For the Predecessor period of 2020, the weighted-average fair value of each option granted was $6.82. All outstanding stock options were cancelled for no consideration as a result of our emergence from bankruptcy.

Employee Stock Purchase Plan

Successor Employee Stock Purchase Plan

In May 2022, our shareholders approved a new California Resources Corporation Employee Stock Purchase Plan (ESPP), which took effect in July 2022. The ESPP provides our employees with the ability to purchase shares of our common stock at a price equal to 85% of the closing price of a share of our common stock as of the first or last day of each fiscal quarter, whichever amount is less. The maximum number of shares of our common stock which may be issued pursuant to the ESPP is subject to certain annual limits and has a cumulative limit of 1,250,000 shares.

As of December 31, 2022, 16,480 shares were issued under our ESPP.

Predecessor Employee Stock Purchase Plan

On May 26, 2020, our California Resources Corporation 2014 Employee Stock Purchase Plan was terminated by our then Board of Directors. No additional Predecessor shares were issued under the plan after March 31, 2020.

NOTE 11 STOCKHOLDERS' EQUITY

As a result of our bankruptcy as described in *Note 15 Chapter 11 Proceedings*, all of our Predecessor common and preferred stock, including contracts on our equity were cancelled on the Effective Date pursuant to the Plan and 83,319,660 shares of new common stock were issued at emergence.

The following is a summary of changes in our common shares outstanding:

	Common Shares Outstanding
Balance, December 31, 2020	83,319,660
Shares issued for warrant exercises	51,377
Shares issued under stock-based compensation arrangements	18,173
Treasury stock - shares repurchased	(4,089,988)
Balance, December 31, 2021	79,299,222
Shares issued for warrant exercises	312
Shares issued under ESPP	16,480
Treasury stock - shares repurchased	(7,366,272)
Balance, December 31, 2022	71,949,742

Share Repurchase Program

Our Board of Directors has authorized a Share Repurchase Program to acquire up to $850 million of our common stock through December 31, 2023. The repurchases may be effected from time-to-time through open market purchases, privately negotiated transactions, Rule 10b5-1 plans, accelerated stock repurchases, derivative contracts or otherwise in compliance with Rule 10b-18, subject to market conditions. The Share Repurchase Program does not obligate us to repurchase any dollar amount or number of shares and our Board of Directors may modify, suspend, or discontinue authorization of the program at any time. The following is a summary of our share repurchases, held as treasury stock for the periods presented:

	Total Number of Shares Purchased	Dollar Value of Shares Purchased	Average Price Paid per Share
	(number of shares)	(in millions)	($ per share)
Year ended December 31, 2021	4,089,988	$148	$36.08
Year ended December 31, 2022	7,366,272	$313	$42.47
Total	11,456,260	$461	$40.19

See *Note 17 Subsequent Events* for more or information on an increase and extension to our Share Repurchase Program.

Dividends

Our Board of Directors declared a cash dividend of $0.17 per share of common stock for the fourth quarter of 2021 and each of the first three quarters of 2022. On November 2, 2022, our Board of Directors approved an increase in our dividend policy to an expected total annual dividend of $1.13 per share. Dividends are payable to shareholders in quarterly increments, subject to the quarterly approval of our Board of Directors. Our Board of Directors approved a quarterly cash dividend on November 2, 2022 in the amount of $0.2825 per share of common stock. For the years ended December 31, 2022 and 2021, we paid $59 million and $14 million in dividends, respectively. There were no cash dividends declared in the Predecessor or Successor period of 2020.

The actual declaration of future cash dividends, and the establishment of record and payment dates, is subject to final determination by our Board of Directors each quarter after reviewing our financial performance. See *Note 17 Subsequent Events* for information on future cash dividends.

Noncontrolling Interests

<u>*BSP JV*</u>

Our development joint venture with Benefit Street Partners (BSP JV) contemplated that BSP contributed funds to the development of our oil and natural gas properties in exchange for preferred interests in the BSP JV. In September 2021, BSP's preferred interest was automatically redeemed in full under the terms of the joint venture agreement. Prior to the redemption, we made aggregate distributions to BSP of $50 million in 2021 which reduced noncontrolling interest on our consolidated balance sheet and was reported as a financing cash outflow on our consolidated statement of cash flows.

BSP's preferred interest was reported in equity on our consolidated balance sheets and BSP's share of net income (loss) was reported in net income attributable to noncontrolling interests in our consolidated statements of operations for all periods prior to redemption. Upon redemption, we reallocated the remaining balance of $7 million in noncontrolling interest and increased our additional paid-in capital by the same amount.

<u>*Ares JV*</u>

See *Note 15 Chapter 11 Proceedings* for information on our Ares JV and Settlement Agreement.

Warrants

On the Effective Date, we issued warrants exercisable for an aggregate 4,384,182 shares of Successor common stock. The warrants are exercisable at an exercise price of $36 per share until October 2024. The Warrant Agreement contains customary anti-dilution adjustments in the event of any stock split, reverse stock split, stock dividend, equity awards under our Management Incentive Plan or other distributions. The warrant holder may elect, in its sole discretion, to pay cash or to exercise on a cashless basis, pursuant to which the holder will not be required to pay cash for shares of common stock upon exercise of the warrant but will instead receive fewer shares. See *Note 16 Fresh Start Accounting* for additional information.

As of December 31, 2022, we had outstanding warrants exercisable into 4,295,434 shares of our common stock.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) consists of unrealized gains (losses) associated with our pension and postretirement benefit plans. The components of Accumulated Other Comprehensive Income (Loss) at December 31, 2022 and 2021 consisted of the following:

	Total
	(in millions)
December 31, 2020	**$ (8)**
Other comprehensive income before taxes	80
Tax effects	—
Other comprehensive income	80
December 31, 2021	**72**
Other comprehensive income before taxes	13
Tax effects	(4)
Other comprehensive income	9
December 31, 2022	$ 81

The elimination of Predecessor equity balances as part of fresh start accounting resulted in a reclassification of $23 million of accumulated other comprehensive loss to additional paid-in capital upon emergence from bankruptcy. See *Note 16 Fresh Start Accounting* for additional information.

NOTE 12 EARNINGS PER SHARE

Basic and diluted earnings per share (EPS) were calculated using the treasury stock method for the Successor periods and the two-class method, which is required when there are participating securities, for the Predecessor periods. Certain of our restricted and performance stock unit awards outstanding prior to our emergence from bankruptcy were considered participating securities because they had non-forfeitable dividend rights at the same rate as our pre-emergence common stock. Our restricted and performance stock unit awards granted subsequent to our emergence from bankruptcy, as described in *Note 10 Stock-Based Compensation*, are not considered participating securities since the dividend rights on unvested shares are forfeitable.

Under the two-class method, undistributed earnings allocated to participating securities are subtracted from net income attributable to common stock in determining net income available to common stockholders. In loss periods, no allocation is made to participating securities because participating securities do not share in losses.

For basic EPS, the weighted-average number of common shares outstanding excludes underlying shares related to equity-settled awards and warrants. For diluted EPS, the basic shares outstanding are adjusted by adding potential common shares, if dilutive. Under the treasury stock method, we assume that proceeds from the exercise of options, warrants and similar instruments are used to purchase common stock at average market price of our stock each period. For PSUs, we use the 60-trading day volume weighted-average prices of our common stock to determine the percentage earned for each period and the number of potential common shares included in diluted EPS. An insignificant number of potential common shares were not earned, and therefore were not treated as issued in our diluted EPS calculation for the year ended December 31, 2022.

The following table presents the calculation of basic and diluted EPS.

(in millions, except per share amounts)	Successor Year ended December 31, 2022	Successor Year ended December 31, 2021	Successor November 1, 2020 - December 31, 2020	Predecessor January 1, 2020 - October 31, 2020
Numerator for Basic and Diluted EPS				
Net income (loss)	$ 524	$ 625	$ (125)	$ 1,996
Less: Net income attributable to noncontrolling interests	—	(13)	2	(107)
Net income (loss) attributable to common stock	524	612	(123)	1,889
Less: Net income allocated to participating securities	—	—	—	(22)
Modification of noncontrolling interest[(a)]	—	—	—	138
Net (loss) income available to common stockholders	$ 524	$ 612	$ (123)	$ 2,005
Denominator for Basic EPS				
Weighted-average common shares	75.5	82.0	83.3	49.4
Potential dilutive common shares:				
Restricted Stock Units	0.7	0.5	—	0.2
Performance Stock Units	0.7	0.5	—	—
Warrants	0.7	—	—	—
Denominator for Diluted Earnings per Share				
Weighted-average shares - diluted	77.6	83.0	83.3	49.6
EPS				
Basic	$ 6.94	$ 7.46	$ (1.48)	$ 40.59
Diluted	$ 6.75	$ 7.37	$ (1.48)	$ 40.42

(a) Modification of noncontrolling interest relates to the deemed redemption of ECR's noncontrolling interest in the Ares JV in the third quarter of 2020. For more information on the Ares JV and the Settlement Agreement, see *Note 15 Chapter 11 Proceedings*.

The following table presents potentially dilutive weighted-average common shares which were excluded from the denominator for diluted earnings per share:

	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
(in millions)				
Shares issuable upon exercise of warrants which were issued at emergence from bankruptcy	—	4.4	4.4	—
Shares issuable upon exercise of warrants in connection with our Alpine JV	—	—	—	1.3
Shares issuable upon settlement of RSUs	—	—	—	0.2
Shares issuable upon settlement of PSUs	—	—	—	0.8
Shares issuable upon exercise of stock options	—	—	—	1.7
Total antidilutive shares	—	4.4	4.4	4.0

NOTE 13 PENSION AND POSTRETIREMENT BENEFIT PLANS

We have various qualified and non-qualified benefit plans for our salaried and union and nonunion hourly employees.

Defined Contribution Plans

All of our employees are eligible to participate in our tax-qualified, defined contribution retirement plan that provides for periodic cash contributions by us based on annual cash compensation and employee deferrals.

Certain salaried employees participate in supplemental plans that restore benefits lost due to government limitations on qualified plans. As of December 31, 2022 and 2021, we recognized $24 million and $30 million in other long-term liabilities for these supplemental plans, respectively.

We expensed $18 million in 2022, $19 million in 2021, $4 million in the Successor period of 2020 and $28 million in the Predecessor period of 2020 under the provisions of these defined contribution and supplemental plans.

Defined Benefit Plans

Participation in defined benefit pension plans sponsored by us is limited. During 2022, approximately 60 employees accrued benefits under these plans, all of whom were union employees.

Pension costs for the defined benefit pension plans, determined by independent actuarial valuations, are funded by us through payments to trust funds, which are administered by independent trustees.

Postretirement Benefit Plans

We provide postretirement medical and dental benefits for our eligible former employees and their dependents. Our former employees are required to make monthly contributions for the coverage, but the benefits are primarily funded by us as claims are paid during the year.

In 2021, we adopted a postretirement benefit design change, which terminated the employer cost sharing for post age 65 retiree health benefits effective as of January 1, 2022. Our retiree health care benefits provided up to age 65 to current and future retirees who meet certain eligibility requirements were not affected by this change. As a result of this change, our postretirement medical benefit obligation was remeasured as of September 30, 2021. The remeasurement resulted in a decrease to the benefit obligation of $65 million with a corresponding increase to accumulated other comprehensive income. The benefit from the change in plan design will be recognized in our statement of operations over the average remaining years of future service for active employees as a component of other non-operating expenses, net.

Obligations and Funded Status of our Defined Benefit Plans

The following table shows the amounts recognized on our balance sheets related to pension and postretirement benefit plans, as well as plans that we or our subsidiaries sponsor (in millions):

	December 31, 2022		December 31, 2021	
	Pension	Postretirement	Pension	Postretirement
Amounts recognized on the balance sheet				
Other assets	$ 2	$ —	$ —	$ —
Accrued liabilities	—	(4)	—	(4)
Other long-term liabilities	—	(33)	(15)	(44)
	$ 2	$ (37)	$ (15)	$ (48)
Amounts recognized in accumulated other comprehensive income (loss), net of tax	$ 2	$ 79	$ (2)	$ 74

The following table shows the funding status of our pension and post-retirement benefit plans along with a reconciliation of our benefit obligations and changes in fair value of plan assets (in millions):

	Year ended December 31, 2022	Year ended December 31, 2021
Pension		
Changes in the benefit obligation		
Benefit obligation - beginning of year	$ 44	$ 47
Service cost - benefits earned during the period	1	1
Interest cost on projected benefit obligation	1	1
Actuarial (gain) loss[(a)]	(12)	2
Benefits paid	(4)	(7)
Benefit obligation - end of year	$ 30	$ 44
Changes in plan assets		
Fair value of plan assets - beginning of year	$ 29	$ 32
Actual return on plan assets	(5)	2
Employer contributions	12	2
Benefits paid	(4)	(7)
Fair value of plan assets - end of year	$ 32	$ 29
Net benefit asset (liability)	$ 2	$ (15)
Postretirement		
Changes in the benefit obligation (in millions)		
Benefit obligation - beginning of year	$ 49	$ 129
Service cost - benefits earned during the period	2	4
Interest cost on projected benefit obligation	1	3
Actuarial (gain) loss[(b)]	(12)	(17)
Benefits paid	(2)	(5)
Plan amendment	—	(65)
Benefit obligation - end of year	$ 38	$ 49
Changes in plan assets		
Fair value of plan assets - beginning of year	$ 1	$ —
Employer contributions	2	6
Benefits paid	(2)	(5)
Fair value of plan assets - end of year	$ 1	$ 1
Net benefit liability	$ (37)	$ (48)

(a) The gain reflected in the changes in the pension benefit obligation for the year ended December 31, 2022 was primarily due to the increase in the discount rate from 2.79% to 5.19% and other valuation assumption changes.

(b) The gain reflected in the changes in the postretirement benefit obligation for the year ended December 31, 2022 was primarily due to the increase in the discount rate from 2.75% to 5.20%.

The following table sets for the details of our obligations and assets related to our defined benefit pension plans for the years ended December 31:

(in millions)	2022	2021
Projected benefit obligation	$ 30	$ 44
Accumulated benefit obligation	$ 27	$ 39
Fair value of plan assets	$ 32	$ 29

Components of Net Periodic Benefit Cost

We record the service cost component of net periodic pension cost with other employee compensation and all other components, including settlement costs, are reported as other non-operating income (expenses), net on our consolidated statements of operations. The following table set forth the components of our net periodic pension and postretirement benefit costs (in millions):

	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
Pension				
Net periodic benefit costs				
Service cost - benefits earned during the period	$ 1	$ 1	$ —	$ 1
Interest cost on projected benefit obligation	1	1	—	1
Expected return on plan assets	(1)	(1)	—	(1)
Amortization of net actuarial loss	—	—	—	1
Settlement costs	—	—	—	1
Net periodic benefit costs	$ 1	$ 1	$ —	$ 3
Postretirement				
Net periodic benefit costs				
Service cost - benefits earned during the period	$ 2	$ 4	$ 1	$ 4
Interest cost on projected benefit obligation	1	3	—	3
Amortization of prior service cost credit	(5)	(1)	—	—
Amortization of net actuarial gain/loss	—	—	—	—
Settlement costs	—	—	—	1
Net periodic benefit costs	$ (2)	$ 6	$ 1	$ 8

Components of accumulated other comprehensive income (loss) (AOCI) are presented net of tax. The following table presents the changes in plan assets and benefit obligations recognized in other comprehensive (loss) income attributable to common stock (in millions):

	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
Pension				
Net actuarial gain (loss)	$ 4	$ (1)	$ (1)	$ (1)
Settlement costs	—	—	—	1
Amortization of net actuarial gain/loss	—	—	—	1
Total	$ 4	$ (1)	$ (1)	$ 1
Postretirement				
Net actuarial gain (loss)	$ 9	$ 17	$ (7)	$ (2)
Net prior service credit	—	65	—	—
Settlement costs	—	—	—	1
Amortization of prior service cost credit	(4)	(1)	—	—
Total	$ 5	$ 81	$ (7)	$ (1)

Settlement costs related to our pension and postretirement plans in the Predecessor period of 2020 were associated with early retirements.

The following tables sets forth the valuation assumptions, on a weighted-average basis, used to determine our benefit obligations and net periodic benefit cost:

	Year ended December 31, 2022	Year ended December 31, 2021
Pension		
Benefit Obligation Assumptions		
Discount rate	5.19%	2.79%
Rate of compensation increase	4.00%	4.00%
Net Periodic Benefit Cost Assumptions		
Discount rate	2.79%	2.42%
Assumed long-term rate of return on assets	5.50%	6.25%
Rate of compensation increase	4.00%	4.00%

	2022	October 1, 2021 - December 31, 2021	January 1, 2021 - September 30, 2021
Postretirement[(a)]			
Benefit Obligation Assumptions			
Discount rate	5.20%	2.75%	2.69%
Net Periodic Benefit Cost Assumptions			
Discount rate	2.75%	2.69%	2.92%

(a) Our plan design change on September 30, 2021 resulted in a remeasurement of our postretirement benefit obligations.

For pension plans and postretirement benefit plans that we or our subsidiaries sponsor, we based the discount rate on the FTSE Above Median yield curve in 2022 and the Aon AA Above Median yield curve in 2021. The weighted-average rate of increase in future compensation levels is consistent with our past and anticipated future compensation increases for employees participating in pension plans that determine benefits using compensation. The assumed long-term rate of return on assets is estimated with regard to current market factors but within the context of historical returns for the asset mix that exists at year end.

In 2022 and 2021, we used the Society of Actuaries Pri-2012 mortality assumptions reflecting the MP-2021 scale which plan sponsors in the U.S. use in the actuarial valuations that determine a plan sponsor's pension and postretirement obligations.

The postretirement benefit obligation was determined by application of the terms of medical and dental benefits, including the effect of established maximums on covered costs, together with relevant actuarial assumptions and healthcare cost trend rates projected at an assumed U.S. Consumer Price Index (CPI) increase of 2.52% and 2.57% as of December 31, 2022 and 2021, respectively. Under the terms of our postretirement plans, participants other than certain union employees pay for all medical cost increases in excess of increases in the CPI. For those union employees, we projected that, as of December 31, 2022, health care cost trend rates would be 7.00% in 2023 decreasing until they reach 4.50% in 2033 and remain at 4.50% thereafter. For those union employees, we projected that, as of December 31, 2021, health care cost trend rates would be 6.00% in 2022 decreasing until they reach 4.50% in 2029 and remain at 4.50% thereafter.

The actuarial assumptions used could change in the near term as a result of changes in expected future trends and other factors that, depending on the nature of the changes, could cause increases or decreases in the plan assets and liabilities.

Fair Value of Plan Assets

We employ a total return investment approach that uses a diversified blend of equity and fixed-income investments to optimize the long-term return of plan assets at a prudent level of risk. Equity investments were diversified across U.S. and non-U.S. stocks, as well as differing styles and market capitalizations. Other asset classes, such as private equity and real estate, may have been used with the goals of enhancing long-term returns and improving portfolio diversification. In 2022 and 2021, the target allocation of plan assets was 50% and 65% equity securities and 50% and 35% debt securities, respectively. Investment performance was measured and monitored on an ongoing basis through quarterly investment portfolio and manager guideline compliance reviews, annual liability measurements and periodic studies. Our postretirement benefit plan assets of $1 million are invested in mutual funds (Level 1 on the fair value hierarchy) with target allocations of 40% equities and 60% debt securities.

The fair values of our pension plan assets by asset category are as follows:

	Fair Value Measurements at December 31, 2022			
	Level 1	Level 2	Level 3	Total
Asset Class	(in millions)			
Comingled funds				
Bonds	—	17	—	17
Commodities	—	1	—	1
U.S. equity	—	4	—	4
International equity	—	10	—	10
Total pension plan assets	$ —	$ 32	$ —	$ 32

	Fair Value Measurements at December 31, 2021			
	Level 1	Level 2	Level 3	Total
Asset Class	(in millions)			
Cash equivalents	$ 5	$ —	$ —	$ 5
Commingled funds				
Fixed income	—	2	—	2
U.S. equity	—	3	—	3
International equity	—	2	—	2
Mutual funds				
Bond funds	5	—	—	5
Value funds	2	—	—	2
Growth funds	5	—	—	5
Guaranteed deposit account	—	—	5	5
Total pension plan assets	$ 17	$ 7	$ 5	$ 29

Expected Contributions and Benefit Payments

In 2023, we do not expect to contribute to our pension plans and expect to contribute $5 million to our postretirement benefit plan. Estimated future undiscounted benefit payments by the plans, which reflect expected future service, as appropriate, are as follows:

	Pension Benefits	Postretirement Benefits
For the years ended December 31,	(in millions)	
2023	$ 7	$ 5
2024	$ 2	$ 4
2025	$ 2	$ 4
2026	$ 2	$ 3
2027	$ 2	$ 3
2028 to 2032 Payouts	$ 10	$ 12

NOTE 14 REVENUE

Revenue from customers is recognized when obligations under the terms of a contract are satisfied. See *Note 1 Nature of Business, Summary of Significant Accounting Policies and Other* for disaggregated revenue by commodity type.

Commodity Sales Contracts

We consider our performance obligations to be satisfied upon delivery (and transfer of control) of the commodity. In certain instances, transportation and processing fees are incurred by us prior to delivery to customers. We record these transportation and processing fees as transportation costs on our consolidated statements of operations.

Our contracts with customers are generally less than a year and based on index prices. We recognize revenue in the amount that we expect to receive once we are able to adequately estimate the consideration (i.e., when market prices are known). Our contracts with customers typically require payment within 30 days following the month of delivery.

Electricity

The electrical output of our Elk Hills power plant that is not used in our operations is sold to the wholesale power market and a utility under a power purchase and sales agreement (PPA) through December 2023, which includes a monthly capacity payment plus a variable payment based on the quantity of power purchased each month. Revenue is recognized when obligations under the terms of a contract are satisfied; generally, this occurs upon delivery of the electricity. Revenue is measured as the amount of consideration we expect to receive based on the average index or California Independent System Operator (CAISO) market pricing with payment due the month following delivery. Payments under our PPA are settled monthly. We consider our performance obligations to be satisfied upon delivery of electricity or as the contracted amount of energy is made available to the customer in the case of capacity payments.

Sales of Purchased Natural Gas

To transport our natural gas as well as third-party volumes, we have entered into firm pipeline commitments. In addition, we may from time-to-time enter into natural gas purchase and sale agreements with third parties to take advantage of market dislocations. We report sales of purchased natural gas in total operating revenues and associated purchased natural gas expense related to our trading activities in total operating expenses on our consolidated statements of operations. We consider our performance obligations to be satisfied upon transfer of control of the commodity.

NOTE 15 CHAPTER 11 PROCEEDINGS

The commencement of the Chapter 11 Cases, as described in *Note 1 Nature of Business, Summary of Significant Accounting Policies and Other*, constituted an event of default that accelerated our obligations under the following agreements: (i) Credit Agreement, dated as of September 24, 2014, among JPMorgan Chase Bank, N.A., as administrative agent, and the lenders that are party thereto (2014 Revolving Credit Facility), (ii) Credit Agreement, dated as of August 12, 2016, among The Bank of New York Mellon Trust Company, N.A., as collateral and administrative agent, and the lenders that are party thereto (2016 Credit Agreement), (iii) Credit Agreement, dated as of November 17, 2017, among The Bank of America Mellon Trust Company, N.A., as administrative agent, and the lenders that are party thereto (2017 Credit Agreement), and (iv) the indentures governing our 8% Senior Secured Second Lien Notes due 2022 (Second Lien Notes), 5.5% Senior Notes due 2021 (2021 Notes) and 6% Senior Notes due 2024 (2024 Notes). This resulted in the automatic and immediate acceleration of all of our outstanding pre-petition long-term debt. Any efforts to enforce payment obligations related to the acceleration of our long-term debt were automatically stayed by the commencement of our Chapter 11 Cases, and the creditors' rights of enforcement were subject to the applicable provisions of the Bankruptcy Code.

Upon the Effective Date, the balances of the 2016 Credit Agreement, 2017 Credit Agreement, Second Lien Notes, 2021 Notes and 2024 Notes were cancelled pursuant to the terms of the Plan, resulting in a gain of approximately $4 billion included in “Reorganization items, net” on our consolidated statement of operations for the period ended October 31, 2020. Our 2014 Revolving Credit Facility was repaid in full with proceeds from our debtor-in-possession facilities described below and terminated.

Debtor-in-Possession Credit Agreements

On July 23, 2020, we entered into a Senior Secured Superpriority DIP Credit Agreement with JP Morgan, as administrative agent, and certain other lenders (Senior DIP Credit Agreement), which provided for the senior DIP facility in an aggregate principal amount of up to $483 million (Senior DIP Facility). The Senior DIP Facility included a $250 million revolving facility which was primarily used by us to (i) fund working capital needs, capital expenditures and additional letters of credit during the pendency of the Chapter 11 Cases and (ii) pay certain costs, fees and expenses related to the Chapter 11 Cases and the Senior DIP Facility. Following a hearing, the Bankruptcy Court entered a final order on August 14, 2020, which approved the Senior DIP Facility on a final basis. The Senior DIP Facility also included (i) a $150 million letter of credit facility which was used to redeem letters of credit outstanding under the 2014 Revolving Credit Facility as issued under the Senior DIP Facility, and (ii) $83 million of term loan borrowings which were used to repay a portion of the 2014 Revolving Credit Facility. The Senior DIP Facility allowed for the issuance of an additional $35 million of letters of credit.

On July 23, 2020, we entered into a Junior Secured Superpriority DIP Credit Agreement with Alter Domus, as administrative agent, and certain lenders (Junior DIP Credit Agreement), which provided for a junior DIP facility in an aggregate principal amount of $650 million (Junior DIP Facility and together with the Senior DIP Facility, the DIP Facilities). The proceeds of the Junior DIP Facility were used to (i) refinance in full all remaining obligations under the 2014 Revolving Credit Facility and (ii) pay certain costs, fees and expenses related to the Chapter 11 Cases and the Junior DIP Facility.

The Senior DIP Credit Agreement and Junior DIP Credit Agreement both contained representations, warranties, covenants and events of default that are customary for DIP facilities of their type, including certain milestones applicable to the Chapter 11 Cases, compliance with an agreed budget, hedging on not less than 25% of our share of expected crude oil production for a specified period, and other customary limitations on additional indebtedness, liens, asset dispositions, investments, restricted payments and other negative covenants, in each case subject to exceptions.

Borrowings under the Senior DIP Facility bore interest at the London interbank offered rate (LIBOR) plus 4.5% for LIBOR loans and the alternative base rate (ABR) plus 3.5% for alternative base rate loans. We also agreed to pay an upfront fee equal to 1.0% on the commitment amount of the Senior DIP Facility and quarterly commitment fees of 0.5% on the undrawn portion of the Senior DIP Facility.

Borrowings under the Junior DIP Facility bore interest at a rate of LIBOR plus 9.0% for LIBOR loans and ABR plus 8.0% for alternate base rate loans. We also agreed to pay an upfront fee equal to 1.0% of the commitment amount funded on the closing date and a fronting fee to a fronting lender.

Certain of our subsidiaries, including each of the debtors in the Chapter 11 Cases, guaranteed all obligations under the Senior DIP Credit Agreement and Junior DIP Credit Agreement. We also granted liens on substantially all of our assets, whether now owned or hereafter acquired to secure the obligations under the Senior DIP Credit Agreement and Junior DIP Credit Agreement.

The Senior DIP Facility was repaid in full and terminated on the Effective Date using proceeds borrowed under our new Revolving Credit Facility discussed in *Note 4 Debt*. The Junior DIP Facility was also repaid in full and terminated on the Effective Date using (i) $200 million from the Second Lien Term Loan discussed in *Note 4 Debt* and (ii) $450 million from the Subscription Rights Offering discussed below.

Ares JV Settlement Agreement and Noncontrolling Interest

In February 2018, our wholly-owned subsidiary California Resources Elk Hills, LLC (CREH) entered into a midstream JV with ECR, a portfolio company of Ares, with respect to the Elk Hills power plant (a 550-megawatt natural gas fired power plant) and a 200 MMcf/day cryogenic gas processing plant. These assets were held by the joint venture entity, Elk Hills Power, LLC (Ares JV or Elk Hills Power), and each of CREH and ECR held an equity interest in this entity. Our consolidated statements of operations for the Predecessor reflect the operations of the Ares JV, with ECR's share of net income (loss) reported in net income attributable to noncontrolling interests. Distributions to ECR reduced the carrying amount of noncontrolling interests on our consolidated balance sheets and are reported as a financing cash outflow for the Predecessor on our consolidated statements of cashflows. ECR's redeemable noncontrolling interests were reported in mezzanine equity due to an embedded optional redemption feature.

Prior to our Effective Date, we held 50% of the Class A common interest and 95.25% of the Class C common interest in the Ares JV. ECR held 50% of the Class A common interest, 100% of the Class B preferred interest and 4.75% of the Class C common interest. The Ares JV was required to distribute each month its excess cash flow over its working capital requirements first to the Class B holders and then to the Class C common interests, on a pro-rata basis.

We entered into a Settlement Agreement with ECR and Ares which, among other things, granted us the right (Conversion Right) to acquire all (but not less than all) of the equity interests of Elk Hills Power owned by ECR in exchange for the EHP Notes, 17.3 million shares of common stock and approximately $2 million in cash. The Conversion Right was exercised on the Effective Date. See *Note 4 Debt* for more information on the EHP Notes.

Although certain provisions in the Settlement Agreement were not effective until certain conditions were met, such as the Bankruptcy Court entering a final order, we determined that the amended terms were substantively different such that the existing Class A common, Class B preferred and Class C common member interests held by ECR were treated as redeemed in exchange for new member interests issued at fair value in the third quarter of 2020. The estimated fair value of the new member interests was lower than the carrying value of the existing member interests by $138 million. In accordance with GAAP, the modification of noncontrolling interest was recorded to additional paid-in capital and was included in our earnings per share calculations. See *Note 12 Earnings per Share* for adjustments to net income (loss) attributable to common stock of the Predecessor which includes a modification of noncontrolling interest.

We exercised the Conversion Right on the Effective Date and issued the EHP Notes in the aggregate principal amount of $300 million, new common stock comprising approximately 20.8% (subject to dilution) of our outstanding common stock at that time and approximately $2 million in cash (Conversion). Upon the Conversion, Elk Hills Power became our indirect wholly-owned subsidiary, and Ares and its affiliates ceased to have any direct or indirect interest in Elk Hills Power. In connection with the Conversion, Elk Hills Power's limited liability company agreement was amended and restated.

The following table presents the changes in noncontrolling interests for our consolidated joint ventures during the Predecessor period ended October 31, 2020, including both our BSP JV and Ares JV.

	Equity Attributable to Noncontrolling Interests			Mezzanine Equity - Redeemable Noncontrolling Interest	
	Ares JV	BSP JV	Total	Ares JV	Total
			(in millions)		
Balance, December 31, 2019	$ —	$ 93	$ 93	$ 802	$ 802
Net income (loss) attributable to noncontrolling interests	3	10	13	94	94
Distributions to noncontrolling interest holders	(3)	(34)	(37)	(67)	(67)
Modification of noncontrolling interest	—	—	—	(138)	(138)
Acquisition of noncontrolling interest	—	—	—	(691)	(691)
Fair value adjustment of noncontrolling interest in fresh start accounting	—	7	7	—	—
Balance, October 31, 2020	$ —	$ 76	$ 76	$ —	$ —

In connection with the Conversion, on the Effective Date, we entered into a Sponsor Support Agreement dated the Effective Date (Support Agreement) pursuant to which, among other things, the parties agreed that Elk Hills Power will be our primary provider of electricity to, and will be the primary processor of our natural gas produced from, the Elk Hills field, which is consistent with our current practice.

On the Effective Date, in connection with the Conversion, we terminated: (a) the Commercial Agreement, dated as of February 7, 2018, by and between Elk Hills Power and CREH and (b) the Master Services Agreement, dated as of February 7, 2018, by and between Elk Hills Power and CREH.

Rights Offering and Backstop

Pursuant to the Plan, we issued subscription rights to holders of our 2017 Credit Agreement, 2016 Credit Agreement, Second Lien Notes, 2021 Notes and 2024 Notes (Rights Offering). These subscription rights entitled holders to purchase up to $450 million of newly issued shares of common stock at $13 per share upon our emergence from bankruptcy. Certain holders of our pre-emergence indebtedness agreed to backstop the Rights Offering and purchase additional shares in the event the Rights Offering was not fully subscribed in exchange for a premium. The Rights Offering closed on the Effective Date and we issued 38.1 million shares of common stock pursuant to the Rights Offering at that time, including 3.5 million common shares issued to the backstop parties as a premium.

Emergence

The following transactions occurred on October 27, 2020, the effective date of the Plan, where we issued an aggregate of 83.3 million shares of new common stock, reserved 4.4 million shares for future issuance upon exercise of the warrants described in *Note 11 Stockholders' Equity* and reserved 9.3 million shares for future issuance under our management incentive plan described in *Note 10 Stock-Based Compensation*:

- We acquired all of the member interests in the Ares JV held by ECR in exchange for the EHP Notes, 17.3 million shares of new common stock and approximately $2 million in cash;

- Holders of secured claims under the 2017 Credit Agreement received 22.7 million shares of new common stock in exchange for those claims, and holders of deficiency claims under the 2017 Credit Agreement and all outstanding obligations under the 2016 Credit Agreement, Second Lien Notes, 2021 Notes and 2024 Notes received 4.4 million shares of new common stock in exchange for those claims;

- In connection with the Subscription Rights and Backstop Commitment Agreement, 34.6 million shares of new common stock were issued in exchange for $446 million (net of a $4 million allocation adjustment credit paid to certain backstop parties), the gross proceeds of which were used to pay down our Junior DIP Facility;

- We issued 3.5 million shares as consideration for the backstop commitment premium; and

- We issued an aggregate of 821,000 shares to the lenders under our Junior DIP Facility as an exit fee.

All existing equity interests of the Predecessor, including contracts on equity, were cancelled and their holders received no recovery.

As a condition to our emergence, we repaid the outstanding balance of our debtor-in-possession financing with proceeds from our equity offering, Second Lien Term Loan and our new Revolving Credit Facility. For more information on our post-emergence indebtedness, see *Note 4 Debt*.

On October 27, 2020, all but one of our existing directors resigned and seven new non-employee directors were appointed to our Board of Directors (Board) in connection with our emergence from bankruptcy. In addition, our former Chief Executive Officer and director Todd A. Stevens departed on December 31, 2020.

NOTE 16 FRESH START ACCOUNTING

Fresh Start Accounting

We adopted fresh start accounting upon emergence from bankruptcy because (1) the holders of existing voting shares prior to emergence received less than 50% of our new voting shares following our emergence from bankruptcy and (2) the reorganization value of our assets immediately prior to the confirmation of the Plan was less than the post-petition liabilities and allowed claims, which were included in liabilities subject to compromise as of our emergence date.

For financial reporting purposes, fresh start accounting was applied as of October 31, 2020, an accounting convenience date, to coincide with the timing our normal month-end close process. We evaluated and concluded that events between October 28, 2020 and October 31, 2020 were not significant and the use of an accounting convenience date was appropriate.

Under fresh start accounting, the reorganization value of the emerging entity was assigned to individual assets and liabilities based on their estimated relative fair values. Reorganization value represents the fair value of our total assets prior to the consideration of liabilities and is intended to approximate the amount a willing buyer would pay for the assets immediately after a restructuring. The reorganization value was derived from our enterprise value, which was the estimated fair value of our long-term debt, asset retirement obligations and shareholder’s equity at emergence. In support of the Plan, our enterprise value was estimated and approved by the Bankruptcy Court to be in the range of $2.2 billion to $2.8 billion.

This valuation analysis was prepared using reserve information, development schedules, other financial information and financial projections, and applying standard valuation techniques, including net asset value analysis, precedent transactions analyses and comparable public company analyses. We engaged third-party valuation advisors to assist in determining the value of our Elk Hills power plant, cryogenic gas processing plant, certain real estate and warrants. Using these valuations along with our own internal estimates and assumptions for the value of our proved oil and natural gas reserves, we estimated our enterprise value to be $2.5 billion for financial reporting purposes.

The following is a summary of our valuation approaches and assumptions for significant non-current assets and liabilities, which excludes our working capital where our carrying value approximated fair value.

Property, Plant and Equipment

Our principal assets are our oil and natural gas properties. In valuing our proved oil and natural gas properties we used an income approach. Our estimated future revenue, operating costs and development plans were developed internally by our reserve engineers. We applied a discount rate using a market-participant weighted average cost of capital which utilized a blended expected cost of debt and expected returns on equity for similar industry participants. We used a risk-adjusted discount rate for our proved undeveloped locations only. We estimated futures prices to calculate future revenue, as reported on the ICE Brent for oil and NGLs and NYMEX Henry Hub for natural gas as of October 31, 2020, adjusted for pricing differentials and without giving effect to derivative transactions. Operating costs and realized prices for periods after the forward price curve becomes illiquid were adjusted for inflation. No value was ascribed to unproved locations.

The fair value of our Elk Hills power plant, cryogenic gas processing facility (CGP-1) and commercial building in Bakersfield were estimated using a cost approach. The cost approach estimates fair value by considering the amount required to construct or purchase a new asset of equal utility at current prices, with adjustments for asset function, age, physical deterioration and obsolescence. We also considered the history of major capital expenditures.

We internally valued our surface acreage based on recent market data.

Right of Use Assets and Lease Liabilities

The fair value of ROU assets and associated lease liabilities were measured at the present value of the remaining fixed minimum lease payments as if the leases were new leases at emergence. We used our incremental borrowing rate as the discount rate in determining the present value of the remaining lease payments. Based upon the corresponding lease term, our incremental borrowing rates ranged from 4% to 5%.

Pension and Postretirement Benefit Plans

The valuations of our pension liabilities and postretirement benefit obligations were performed by a third-party actuary. Valuation assumptions, including discount rates, expected future returns on plan assets, rates of future salary increases, rates of future increases in medical costs, turnover and mortality rates were developed in consultation with the third-party actuary based on current market conditions, current mortality rates and our expectation for future salary increases.

Long-term Debt Obligations

The fair value of our post-emergence long-term debt approximated carrying value based on the terms of the debt instruments and stated interest rates.

Asset Retirement Obligations

The fair value of our asset retirement obligations was estimated using a discounted cash flow approach for existing idle and currently producing wells and facilities. We estimated an average plugging and abandonment cost by field based on historical averages. We also factored in our testing plans related to idle well management and estimated failure rates to determine the timing of the cash flows. We utilized a credit adjusted risk free rate as our discount rate which was based on our credit rating and expected cost of borrowing at our emergence date. Our asset retirement obligations were reduced to our working interest share and factored in cost recovery related to our PSCs.

Warrants

The fair value of the warrants was estimated using a Black-Scholes model, a commonly used option pricing model. The Black-Scholes was used to estimate the fair value of our warrants with a stock price equal to book equity value per share, strike price, time to expiration, risk-free rate, equity volatility, which was based on a peer group of energy companies and dividend yield, which we estimated to be zero.

Reorganization Value

The following table summarizes our enterprise value upon emergence (in millions):

Fair value of total equity upon emergence	$	1,345
Fair value of long-term debt		725
Fair value of asset retirement obligations		593
Less: Unrestricted cash[(a)]		(163)
Total Enterprise Value	**$**	**2,500**

(a) Includes $118 million of cash used to temporarily collateralize letters of credit at our emergence date.

The following table reconciles our enterprise value to our reorganization value, or total asset value, upon emergence (in millions):

Enterprise value	$	2,500
Add: Unrestricted cash[(a)]		163
Add: Current liabilities[(b)]		396
Add: Other long-term liabilities[(b)]		231
Less: Other		(2)
Reorganization value	**$**	**3,288**

(a) Includes $118 million of cash used to temporarily collateralize letters of credit.
(b) Excludes asset retirement obligations of $50 million in current liabilities and $543 million in other long-term liabilities.

Consolidated Balance Sheet

The following consolidated balance sheet, with accompanying explanatory notes, illustrates the effects of the transactions contemplated by the Plan (Reorganization Adjustments) and fair value adjustments resulting from the adoption of fresh start accounting (Fresh Start Adjustments) as of October 31, 2020 (in millions):

	Predecessor	Reorganization Adjustments		Fresh Start Adjustments		Successor
CURRENT ASSETS						
Cash	$ 106	$ 97	(1)	$ —		$ 203
Trade receivables	149	—		—		149
Inventories	61	—		—		61
Other current assets, net	104	(2)	(2)	—		102
Total current assets	420	95		—		515
PROPERTY, PLANT AND EQUIPMENT	22,918	—		(20,236)	(12)	2,682
Accumulated depreciation, depletion and amortization	(18,588)	—		18,588	(12)	—
Total property, plant and equipment, net	4,330	—		(1,648)		2,682
OTHER ASSETS	77	18	(3)	(4)	(13)	91
TOTAL ASSETS	$ 4,827	$ 113		$ (1,652)		$ 3,288
CURRENT LIABILITIES						
Debtor-in-possession financing	733	(733)	(4)	—		—
Accounts payable	215	—		—		215
Accrued liabilities	233	(16)	(5)	14	(14)	231
Total current liabilities	1,181	(749)		14		446
LONG-TERM DEBT, NET	—	723	(6)	—		723
OTHER LONG-TERM LIABILITIES	725	—		49	(15)	774
LIABILITIES SUBJECT TO COMPROMISE	4,516	(4,516)	(7)	—		—
MEZZANINE EQUITY						
Redeemable noncontrolling interests	691	(691)	(8)	—		—
EQUITY						
Predecessor preferred stock	—	—		—		—
Predecessor common stock	—	—		—		—
Predecessor additional paid-in capital	5,149	(5,149)	(9)	—		—
Successor preferred stock	—			—		—
Successor common stock	—	1	(10)	—		1
Successor additional paid-in capital	—	1,253	(10)	—		1,253
Successor warrants	—	15	(10)	—		15
Accumulated deficit	(7,481)	9,226	(11)	(1,745)	(16)	—
Accumulated other comprehensive loss	(23)	—		23	(17)	—
Total equity attributable to common stock	(2,355)	5,346		(1,722)		1,269
Equity attributable to noncontrolling interests	69	—		7	(18)	76
Total equity	(2,286)	5,346		(1,715)		1,345
TOTAL LIABILITIES AND EQUITY	$ 4,827	$ 113		$ (1,652)		$ 3,288

Reorganization Adjustments

(1) Net change in cash upon our emergence included the following transactions (in millions):

Proceeds from Revolving Credit Facility	$	225
Proceeds from Subscription Rights and Backstop Commitment, net		446
Proceeds from Second Lien Term Loan		200
Repayment of debtor-in-possession facilities		(733)
Payment of legal, professional and other fees		(15)
Debt issuance costs for the Revolving Credit Facility		(18)
Debt issuance costs for the Second Lien Term Loan		(2)
Acquisition of noncontrolling interest as part of the Settlement Agreement		(2)
Distribution to noncontrolling interest holder		(3)
Payment of accrued interest and bank fees		(1)
Net change	$	97

Our cash balance of $203 million at October 31, 2020 included $158 million of restricted cash, of which $118 million was used to temporarily collateralize letters of credit, $22 million was held for distributions to a JV partner and $18 million was reserved for legal and professional fees related to our Chapter 11 Cases.

(2) Represents the write-off of unamortized insurance premiums for our directors and officers policy, which was cancelled as a result of changing the composition of our Board of Directors.

(3) Represents the capitalization of debt issuance costs for our Revolving Credit Facility.

(4) Represents the payoff of $733 million of debtor-in-possession financing including $83 million of borrowings that were outstanding under our Senior DIP Facility and $650 million of borrowings that were outstanding under our Junior DIP Facility. Refer to *Note 15 Chapter 11 Proceedings* for more information on our debtor-in-possession credit agreements.

(5) Reflects the payment of $15 million for legal, professional and other fees related to our bankruptcy proceedings upon emergence and $1 million for accrued interest and bank fees.

(6) Our exit financing at emergence included the following:

	October 31, 2020 ($ in millions)	
Revolving Credit Facility	$	225
Second Lien Term Loan		200
EHP Notes		300
Long-term debt (principal amount)	**$**	**725**
Debt issuance costs		(2)
Total long-term debt, net	**$**	**723**

For additional information on our Successor debt, refer to *Note 4 Debt*.

(7) Our liabilities subject to compromise at emergence included the following (in millions):

Long-term debt (principal amount):		
2017 Credit Agreement	$	1,300
2016 Credit Agreement		1,000
Second Lien Notes		1,808
2021 Notes		100
2024 Notes		144
Accrued interest		164
Total liabilities subject to compromise	**$**	**4,516**

(8) Represents the acquisition of the noncontrolling interest in our Ares JV. In accordance with the Settlement Agreement, we exercised a conversion right upon our emergence from bankruptcy, allowing us to acquire all (but not less than all) of the equity interests in the Ares JV held by ECR in exchange for the EHP Notes, 17.3 million shares of common stock and approximately $2 million in cash.

(9) Represents the elimination of Predecessor additional paid-in capital.

(10) Represents the fair value of 83.3 million shares of Successor common stock and Warrants issued in accordance with the Plan as follows (in millions):

Par value	$	1
Additional paid-in capital		1,253
Warrants		15
Total	**$**	**1,269**

(11) Represents the decrease in accumulated deficit resulting from reorganization adjustments and the reclassification from Predecessor additional paid-in capital.

Fresh Start Adjustments

(12) Represents fair value adjustments to property, plant and equipment (PP&E), including the elimination of Predecessor accumulated depreciation, depletion and amortization.

The fair value of our PP&E at emergence consisted of the following:

Proved oil and natural gas properties	$	2,409
Facilities and other		273
Total PP&E	**$**	**2,682**

(13) Represents an adjustment to our right of use assets as if our lease agreements were new leases on our emergence date.

(14) Represents a $20 million fair value adjustment to the current portion of asset retirement obligations partially offset by a $5 million decrease in our liability for self-insured medical. Also included are fair value adjustments for our postretirement benefits and a remeasurement of the current portion of our lease liability.

(15) Represents a $36 million fair value adjustment related to the long-term portion of asset retirement obligations and $8 million related to environmental and other abandonment obligations. The adjustment also includes $5 million related to remeasuring our long-term lease liability as if our contracts were new leases.

(16) Represents the elimination of Predecessor accumulated deficit.

(17) Represents the elimination of Predecessor accumulated other comprehensive loss.

(18) Represents a fair value adjustment of the noncontrolling interest in the BSP JV based on discounted expected future cash flows.

NOTE 17 SUBSEQUENT EVENTS

Dividends

On February 23, 2023, our Board of Directors declared a cash dividend of $0.2825 per share of common stock. The dividend is payable to shareholders of record at the close of business on March 6, 2023 and is expected to be paid on March 16, 2023.

Share Repurchase Program

On February 23, 2023 our Board of Directors increased the Share Repurchase Program by $250 million to $1.1 billion and extended the program through June 30, 2024.

Income Taxes

In February 2023, the original tax treatment of the Lost Hills divestiture was amended. As a result, we are no longer limited on the realization of the tax loss and will release our $35 million valuation allowance in the first quarter of 2023. See *Note 3 Divestitures and Acquisitions* for more information on our Lost Hills divestiture and *Note 9 Income Taxes* for more information on our valuation allowance.

Stock-Based Compensation

In February 2023, certain of our executives were granted an aggregate of 329,000 RSUs and 493,000 PSUs. The PSUs cliff vest on either the second or the third anniversary of the grant date. The RSUs vest ratably over either two or three years, with units vesting on the anniversary date of each grant, generally subject to continued employment through the applicable vesting dates.

Supplemental Oil and Gas Information (Unaudited)

The following table sets forth our net operating and non-operating interests in quantities of proved developed and undeveloped reserves of oil (including condensate), NGLs and natural gas and changes in such quantities. Estimated reserves include our economic interests under PSCs in our Long Beach operations in the Wilmington field. All of our proved reserves are located within the state of California.

PROVED DEVELOPED AND UNDEVELOPED RESERVES

	Oil[(a)]	NGLs	Natural Gas	Total[(b)]
	(MMBbl)	(MMBbl)	(Bcf)	(MMBoe)
Balance at December 31, 2019	483	52	654	644
Revisions of previous estimates[(c)]	(164)	(7)	(86)	(185)
Improved recovery	—	—	—	—
Extensions and discoveries	20	1	24	25
Divestitures	(1)	—	(3)	(2)
Production	(25)	(5)	(62)	(40)
Balance at December 31, 2020	313	41	527	442
Revisions of previous estimates[(c)]	50	5	108	73
Improved recovery	1	—	—	1
Extensions and discoveries	4	—	6	5
Acquisitions and divestitures	(3)	(1)	(7)	(5)
Production	(22)	(4)	(58)	(36)
Balance at December 31, 2021	343	41	576	480
Revisions of previous estimates[(c)]	(38)	—	(36)	(44)
Improved recovery	6	—	—	6
Extensions and discoveries	11	1	26	16
Acquisitions and divestitures	(8)	—	(1)	(8)
Production	(20)	(4)	(54)	(33)
Balance at December 31, 2022	294	38	511	417
PROVED DEVELOPED RESERVES				
December 31, 2019	357	45	543	493
December 31, 2020	266	39	460	382
December 31, 2021	282	38	510	405
December 31, 2022[(d)]	251	36	458	363
PROVED UNDEVELOPED RESERVES				
December 31, 2019	126	7	111	151
December 31, 2020	47	2	67	60
December 31, 2021	61	3	66	75
December 31, 2022	43	2	53	54

(a) Includes proved reserves related to economic arrangements similar to PSCs of 92 MMBbl, 111 MMBbl, 85 MMBbl and 125 MMBbl at December 31, 2022, 2021, 2020 and 2019, respectively.

(b) Natural gas volumes have been converted to Boe based on the equivalence of energy content of six Mcf of natural gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

(c) Commodity price changes affect the proved reserves we record. For example, higher prices generally increase the economically recoverable reserves in all of our operations, because the extra margin extends their expected lives and renders more projects economic. Partially offsetting this effect, higher prices decrease our share of proved cost recovery reserves under arrangements similar to production-sharing contracts at our Long Beach operations in the Wilmington field because fewer reserves are required to recover costs. Conversely, when prices drop, we experience the opposite effects. Performance-related revisions can include upward or downward changes to previous proved reserves estimates due to the evaluation or interpretation of recent geologic, production decline or operating performance data.

(d) Approximately 19% of proved developed oil reserves, 7% of proved developed NGLs reserves, 10% of proved developed natural gas reserves and, overall, 16% of total proved developed reserves at December 31, 2022 are non-producing. A majority of our non-producing reserves relate to steamfloods and waterfloods where full production response has not yet occurred due to the nature of such projects.

2022

Revisions of previous estimates – We had net positive price-related revisions of 6 MMBoe primarily resulting from a higher commodity price environment in 2022 compared to 2021. The price revision reflects the extended economic lives of our fields, estimated using 2022 SEC pricing. Additionally, we have experienced higher vendor-related pricing and compensation-related cost increases due to inflation.

We had 16 MMBoe of net negative performance-related revisions which included negative performance-related revisions of 31 MMBoe and positive performance-related revisions of 15 MMBoe. Our negative performance-related revisions primarily were due to wells and incremental waterflood response that underperformed forecasts and removal of proved undeveloped locations due to unsuccessful drilling results in certain areas. Our positive performance-related revisions primarily related to better-than-expected well performance and addition of proved undeveloped locations due to positive drilling results in certain areas. The majority of these revisions were located in the San Joaquin and Los Angeles basins.

We had 34 MMBoe of negative revisions to our proved reserves due to the impact of California regulatory changes and court challenges on our development plans. Of this amount, negative revisions of 20 MMBoe of proved reserves were due to the uncertainty of the outcome of the referendum and potential impact of Senate Bill No. 1137. The majority of these volumes are in the LA Basin. Negative revisions of 14 MMBoe to our proved reserves were due to challenges to Kern County's ability to issue well permits in reliance on an existing EIR for CEQA purposes. The volumes affected by these court challenges are in Kern County. See *Part I, Item 1 & 2 Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

Extensions and discoveries – We added 16 MMBoe from extensions and discoveries resulting from successful drilling and workovers in the San Joaquin and Los Angeles basins.

Acquisitions and Divestitures – We had a reduction of 8 MMBoe which primarily related to our Lost Hills divestiture. See *Note 3 Divestitures and Acquisitions* for more information on these transactions.

2021

Revisions of previous estimates – We had positive price-related revisions of 64 MMBoe primarily resulting from a higher commodity price environment in 2021 compared to 2020. The net price revision reflects the extended economic lives of our fields, estimated using 2021 SEC pricing, partially offset by higher operating costs.

We had 9 MMBoe of net positive performance-related revisions which included positive performance-related revisions of 21 MMBoe and negative performance-related revisions of 12 MMBoe. Our positive performance-related revisions of 21 MMBoe primarily related to better-than-expected well performance and adding proved undeveloped locations due to positive drilling results in certain areas. The positive revision also included proved undeveloped reserves added to our five-year development plans in 2021. Our negative performance-related revisions primarily relate to wells and incremental waterflood response that underperformed forecasts and removal of proved undeveloped locations due to unsuccessful drilling results in certain areas. The majority of these revisions were located in the San Joaquin and Los Angeles basins.

Extensions and discoveries – We added 5 MMBoe from extensions and discoveries resulting from successful drilling and workovers in the San Joaquin and Los Angeles basins.

Acquisitions and Divestitures – We had a reduction of 11 MMBoe in connection with our Ventura divestiture and added 6 MMBoe in connection with our acquisition of the working interest in certain wells from MIRA. See *Note 3 Divestitures and Acquisitions* for more information on these transactions.

<u>2020</u>

Revisions of previous estimates – We had negative price-related revisions of 72 MMBoe primarily resulting from a lower commodity price environment in 2020 compared to 2019. The net price revision reflects the shortened economic lives of our fields, as estimated using 2020 SEC pricing, which for oil was significantly lower than current prices, partially offset by our lower operating costs.

We had 61 MMBoe of net negative performance-related revisions which included negative performance-related revisions of 73 MMBoe and positive performance-related revisions of 12 MMBoe. Our negative performance-related revisions are primarily related to wells that underperformed their forecasts. A significant factor for this underperformance was a reduction in our capital program in 2020 due to the extremely low commodity price environment and constraints during our bankruptcy process. This led to higher overall decline rates due to injection curtailments, capacity limitations and reduced well maintenance. Our positive performance-related revisions of 12 MMBoe primarily related to better-than-expected well performance.

We removed 52 MMBoe of proved undeveloped reserves, all of which were no longer included in our development plans because they did not meet internal investment thresholds at lower SEC prices. The majority of these revisions were located in the San Joaquin and Los Angeles basins.

Extensions and discoveries – We added 25 MMBoe from extensions and discoveries, approximately half of which resulted from the booking of proved undeveloped reserves in connection with fresh start accounting. Successful drilling and workovers in the San Joaquin and Los Angeles basins also contributed to the increase.

CAPITALIZED COSTS

Capitalized costs relating to oil and natural gas producing activities and related accumulated depreciation, depletion and amortization (DD&A) were as follows:

	Successor	
	December 31, 2022	**December 31, 2021**
	(in millions)	(in millions)
Proved properties	$ 2,972	$ 2,626
Unproved properties	2	8
Total capitalized costs	2,974	2,627
Accumulated depreciation, depletion and amortization	(394)	(219)
Net capitalized costs	$ 2,580	$ 2,408

COSTS INCURRED

Costs incurred relating to oil and natural gas activities include capital investments, exploration (whether expensed or capitalized), acquisitions and asset retirement obligations but exclude corporate items. The following table summarizes our costs incurred:

	Successor			Predecessor
	Year ended December 31, 2022	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
		(in millions)		(in millions)
Property acquisition costs				
Proved properties[a]	$ —	$ 53	$ —	$ —
Unproved properties	—	—	—	—
Exploration costs	4	7	1	10
Development costs[b]	389	210	7	35
Costs incurred	$ 393	$ 270	$ 8	$ 45

(a) Acquisition costs relates to our acquisition of MIRA's working interests in certain wells in 2021.
(b) Development costs include a $24 million increase in ARO in 2022 (including assets held for sale). Development costs include a $19 million increase in ARO in 2021. There were no costs incurred for development costs related to ARO in 2020.

RESULTS OF OPERATIONS

Our oil and natural gas producing activities, which exclude items such as asset dispositions, corporate overhead and interest, were as follows:

	Successor						Predecessor	
	Year ended December 31, 2022		Year ended December 31, 2021		November 1, 2020 - December 31, 2020		January 1, 2020 - October 31, 2020	
	(millions)	($/Boe)	(millions)	($/Boe)	(millions)	($/Boe)	(millions)	($/Boe)
Revenues[a]	$ 1,901	$ 57.51	$ 1,729	$ 47.55	$ 235	$ 37.49	$ 1,196	$ 34.98
Operating costs[b]	785	23.75	705	19.39	114	18.19	511	14.95
General and administrative expenses	36	1.09	34	0.94	7	1.12	38	1.11
Other operating expenses[c]	21	0.64	25	0.68	6	0.94	20	0.58
Depreciation, depletion and amortization	175	5.29	190	5.23	31	4.95	299	8.75
Taxes other than on income	111	3.36	103	2.83	4	0.64	106	3.10
Asset impairment	—	—	—	—	—	—	1,733	50.69
Accretion expense	43	1.30	50	1.38	8	1.28	33	0.97
Exploration expenses	4	0.12	7	0.19	1	0.16	10	0.29
Pretax income	726	21.96	615	16.91	64	10.21	(1,554)	(45.46)
Income tax expense[d]	(189)	(5.72)	(144)	(3.96)	(18)	(2.87)	435	12.72
Results of operations	$ 537	$ 16.24	$ 471	$ 12.95	$ 46	$ 7.34	$ (1,119)	$ (32.74)

(a) Revenues include oil, natural gas and NGL sales, cash settlements on our commodity derivatives and other revenue related to our oil and natural gas operations.
(b) Operating costs are the costs incurred in lifting the oil and natural gas to the surface and include gathering, processing, field storage and insurance on proved properties.
(c) Other operating expenses primarily include transportation costs.
(d) Income taxes are calculated on the basis of a stand-alone tax filing entity. The combined U.S. federal and California statutory tax rate was 26%. The effective tax rate for 2022 and 2021 includes the benefit of enhanced oil recovery and marginal well tax credits.

STANDARDIZED MEASURE, INCLUDING YEAR-TO-YEAR CHANGES THEREIN, OF DISCOUNTED FUTURE NET CASH FLOWS

For purposes of the following disclosures, discounted future net cash flows were computed by applying to our proved oil and natural gas reserves the unweighted arithmetic average of the first-day-of-the-month price for each month within the years ended December 31, 2022, 2021 and 2020, respectively. The realized prices used to calculate future cash flows vary by producing area and market conditions. Future operating and capital costs were determined using the current cost environment applied to expectations of future operating and development activities. Future income tax expense was computed by applying, generally, year-end statutory tax rates (adjusted for permanent differences and tax credits) to the estimated net future pre-tax cash flows, after allowing for the deductions for intangible drilling costs and tax DD&A. The cash flows were discounted using a 10% discount factor. The calculations assumed the continuation of existing economic, operating and contractual conditions at December 31, 2022, 2021 and 2020. Such assumptions, which are prescribed by regulation, have not always proven accurate in the past. Other valid assumptions would give rise to substantially different results.

Standardized Measure of Discounted Future Net Cash Flows

	Successor		
(in millions)	December 31, 2022	December 31, 2021	December 31, 2020
Future cash inflows	$ 35,190	$ 28,031	$ 15,532
Future costs			
Operating costs[a]	(15,294)	(13,508)	(9,389)
Development costs[b]	(1,973)	(2,607)	(2,392)
Future income tax expense	(4,843)	(3,124)	(701)
Future net cash flows	13,080	8,792	3,050
Ten percent discount factor	(6,354)	(4,243)	(1,118)
Standardized measure of discounted future net cash flows	$ 6,726	$ 4,549	$ 1,932

(a) Includes general and administrative expenses related to our field operations and taxes other than on income.
(b) Includes asset retirement costs.

Changes in the Standardized Measure of Discounted Future Net Cash Flows from Proved Reserve Quantities

	Successor		
(in millions)	2022	2021	2020
Beginning of year	$ 4,549	$ 1,932	$ 5,231
Sales of oil and natural gas, net of production and other operating costs	(1,156)	(543)	(1,257)
Changes in price, net of production and other operating costs	3,814	3,414	(3,940)
Previously estimated development costs incurred	228	185	519
Change in estimated future development costs	306	(401)	1,032
Extensions, discoveries and improved recovery, net of costs	509	115	122
Revisions of previous quantity estimates[a]	(1,041)	1,114	(1,407)
Accretion of discount	573	226	650
Net change in income taxes	(869)	(1,131)	1,124
Purchases and sales of reserves in place	(141)	(15)	(25)
Change in timing of estimated future production and other	(46)	(347)	(117)
Net change	2,177	2,617	(3,299)
End of year	$ 6,726	$ 4,549	$ 1,932

(a) Includes revisions related to performance and price changes.

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

(in millions)	Balance at Beginning of Period	Charged (Credited) to Costs and Expenses	Charged (Credited) to Other Accounts	Deductions	Balance at End of Period
2022 (Successor)					
Deferred tax valuation allowance	$ —	$ 35	$ —	$ —	$ 35
Other asset valuation allowance	$ —	$ 1	$ —	$ —	$ 1
2021 (Successor)					
Deferred tax valuation allowance	$ 549	$ (526)	$ (23)	$ —	$ —
Other asset valuation allowance	$ —	$ —	$ —	$ —	$ —
November 1, 2020 - December 31, 2020 (Successor)					
Deferred tax valuation allowance	$ 511	$ 35	$ 3	$ —	$ 549
Other asset valuation allowance	$ —	$ —	$ —	$ —	$ —
January 1, 2020 - October 31, 2020 (Predecessor)					
Deferred tax valuation allowance	$ 646	$ (571)	$ 436	$ —	$ 511
Other asset valuation allowance	$ 22	$ (22)	$ —	$ —	$ —

ITEM 9 CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A CONTROLS AND PROCEDURES

Management's Annual Assessment of and Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. Our 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 our assets; (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 our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our 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.

Our management has assessed the effectiveness of our internal control system as of December 31, 2022 based on the criteria for effective internal control over financial reporting described in Internal Control – Integrated Framework issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, our management believes that, as of December 31, 2022, our system of internal control over financial reporting is effective.

Our independent auditors, KPMG LLP, have issued a report on our internal control over financial reporting, which is set forth in *Item 8 – Financial Statements and Supplementary Data.*

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer (CEO) and Chief Financial Officer (CFO), has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act)), as of the end of the period covered by this Annual Report on Form 10-K. Based on that evaluation, our CEO and CFO have concluded that, as of December 31, 2022, our disclosure controls and procedures are effective and are designed to provide reasonable assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission (SEC), and that such information is accumulated and communicated to our management, including our CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act of 1934) identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during the three months ended December 31, 2022 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Limitations on Effectiveness of Controls and Procedures

In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

ITEM 9B OTHER INFORMATION

Management Team Realignment

On February 24, 2023, the Company announced that Francisco J. Leon, the Company's current Executive Vice President and Chief Financial Officer, will succeed Mark A. (Mac) McFarland as the Company's President and Chief Executive Officer, and is expected to join the Company's Board of Directors, effective at the Company's 2023 Annual Meeting of Stockholders. Mr. McFarland will continue to serve as a non-executive member of the Company's Board of Directors and chair of the board of the Company's Carbon TerraVault subsidiary. The Company has an ongoing search for a Chief Financial Officer to succeed Mr. Leon.

Mr. Leon, age 46, has been the Company's Executive Vice President and Chief Financial Officer since August 2020. Prior to that, he served as the Company's Executive Vice President, Corporate Development & Strategic Planning from January 2018 to August 2020 and as the Company's Vice President – Portfolio Management and Strategic Planning from December 2014 to January 2018. Mr. Leon holds an M.B.A. from the University of Texas, Austin and a bi-national Bachelor of Arts degree in International Business from San Diego State University and CETYS Universidad in Mexico.

The Company entered into a new employment agreement with Mr. Leon (the "CEO Employment Agreement") in connection with his anticipated promotion to the position of President and Chief Executive Officer, which will supersede the employment agreement previously maintained by the Company and Mr. Leon, dated June 8, 2021, for his position of Executive Vice-President and Chief Financial Officer of the Company. The CEO Employment Agreement will initially govern his role as the Company's Executive Vice-President and Chief Financial Officer but will automatically begin covering his new role as President and Chief Executive Officer in connection with his anticipated promotion on the date of the Company's 2023 Annual Meeting of Stockholders.

The CEO Employment Agreement provides for an initial two-year term beginning on February 23, 2023 (the "Effective Date") and will automatically renew for an additional one-year term on each anniversary of the Effective Date unless the Company or Mr. Leon provides 90 days' written notice to the other that no such automatic renewal shall occur.

The CEO Employment Agreement provides that Mr. Leon will receive an annual base salary of $750,000. Mr. Leon will also be eligible to receive: (i) an annual cash bonus with a target value equal to 120% of his annual base salary; (ii) participation in those benefit plans and programs of the Company available to similarly situated executives; and (iii) at the same time as other executive officers of the Company receive 2023 annual equity award grants, annual long-term incentive awards (to be comprised 60% of performance stock units and 40% of restricted stock units) under the Company's 2021 Long Term Incentive Plan (as amended, the "LTIP") with a target grant value of 600% of his base salary as in effect on the applicable grant date. The performance stock unit awards will vest over a three-year cliff vesting period beginning on the date of grant, and the restricted stock units will vest in three equal installments over a three-year vesting period beginning on the date of grant. In addition to his annual 2023 LTIP awards described above, Mr. Leon will also receive two separate awards pursuant to the LTIP in 2023: (i) an award of restricted stock units valued at $1,200,000 and (ii) an award of performance units valued at $1,800,000, each award of which will vest over a two-year vesting period.

The CEO Employment Agreement also provides for certain severance payments and benefits to be provided to Mr. Leon upon his termination of employment by the Company without "Cause" (including a termination of employment at the expiration of the term because the Company elected not to renew the CEO Employment Agreement) or the executive's resignation for "Good Reason," death or "Disability" (each quoted term as defined in the CEO Employment Agreement). Upon Mr. Leon's termination of employment for any reason, the CEO Employment Agreement provides that the Company shall pay all unpaid base salary, any unreimbursed business expenses incurred prior to the date on which the employment terminates (as applicable, the "Termination Date"), and all benefits to which he is entitled under the terms of any applicable benefit plan (collectively, the "Accrued Benefits").

Upon Mr. Leon's termination of employment by the Company without Cause (including a termination of employment at the expiration of the term because the Company elected not to renew the Employment Agreement), or by Mr. Leon for Good Reason, Mr. Leon will receive payment of any earned but unpaid annual bonus for the calendar year preceding the calendar year in which the Termination Date occurs and, so long as Mr. Leon executes a release of claims in favor of the Company and its affiliates and abides by the restrictive covenants within the CEO Employment Agreement, Mr. Leon shall receive severance payments, generally payable in monthly installments following the Termination Date consisting of: (i) cash payments equal to a predetermined multiple of annual base salary plus target annual bonus awards for the year in which the termination occurs (the multiple being two (2.0) times, increased to two and one-half (2.5) times if such termination of employment occurs within the one (1)-year period following a qualifying Change in Control (such term as defined in the CEO Employment Agreement); (ii) a pro-rata annual bonus for the calendar year in which the Termination Date occurs, based on actual performance levels earned for the applicable calendar year, (iii) reimbursement for the difference between the amount Mr. Leon pays to effect continued coverage (including coverage for his spouse and eligible dependents) under the Company's group health plans pursuant to the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended, and Mr. Leon's contribution amount that similarly situated executives of the Company pay for the same or similar coverage under such group health plans, during the portion, if any, of the 24-month period for following the Termination Date that Mr. Leon elects to continue coverage, and (iv) full vesting of the restricted stock units and performance stock units previously granted to Mr. Leon during the 2021 calendar year under the LTIP and his original employment agreement.

If Mr. Leon's employment is terminated due to death or Disability, then he will receive (i) the Accrued Benefits, (ii) payment of any earned but unpaid annual bonus for the calendar year preceding the calendar year in which the termination of employment occurs, and (iii) a pro-rata portion of the annual bonus for the calendar year in which the Termination Date occurs, based on actual performance for such calendar year and payable at the time such bonuses are paid to similarly situated executives of the Company.

The foregoing description of the CEO Employment Agreement is qualified in its entirety by reference to the full and complete text of the CEO Employment Agreement, which is attached here as Exhibit 10.25 and incorporated herein by reference.

Retention Awards

In order to incentivize the retention of certain key employees, on February 24, 2023, the Company entered into individual Retention Bonus Agreements with the following named executive officers: Jay A. Bys, Shawn M. Kerns and Michael L. Preston. Each Retention Bonus Agreement provides for the grant of a retention bonus in an aggregate amount that is equal to the annual base salary in effect for that employee at the time of grant. The retention bonus will be subject to installment vesting over an eighteen-month period, with twenty percent becoming vested on the six-month anniversary of the date of grant, an additional twenty percent becoming vested on the twelve-month anniversary of the date of grant, and the remaining sixty percent of the award becoming vested on the eighteen-month anniversary of the date of grant. Vested portions of the retention bonus will become immediately payable following the vesting date. During the retention period, if a participating employee is terminated by the Company without cause or due to the employee’s death or disability, any remaining unvested bonus award will immediately become vested and will be paid to the employee.

The foregoing description of the retention bonus awards are qualified in their entirety by reference to the full and complete text of the form Retention Bonus Agreement that will govern each retention bonus award, which is attached hereto as Exhibit 10.28 and incorporated herein by reference.

ITEM 9C DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10 DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated by reference from our Proxy Statement for the 2023 Annual Meeting of Stockholders, which will be filed with the SEC within 120 days of the fiscal year ended December 31, 2022 (2023 Proxy Statement). See the list of our executive officers and related information below.

Our board of directors has adopted a code of business conduct applicable to all officers, directors and employees, which is available on our website (www.crc.com). We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding amendment to, or waiver from, a provision of our code of business conduct by posting such information on our website at the address specified above.

EXECUTIVE OFFICERS

Executive officers are appointed annually by the Board of Directors. The following table sets forth our current executive officers:

Name	Employment History	Age at February 24, 2023
Mark A. (Mac) McFarland	President, Chief Executive Officer and Director since 2021; Chairman of the Board and Interim Chief Executive Officer 2020 to 2021; GenOn Energy Executive Chairman since December 2018; GenOn Energy President and Chief Executive Officer 2017 to 2018; Luminant Holdings Chief Executive Officer and Executive Vice President, Corporate Development 2013 to 2016; Luminant Holdings Chief Commercial Officer 2008 to 2013.	53
Francisco J. Leon	Executive Vice President and Chief Financial Officer since 2020; Executive Vice President - Corporate Development and Strategic Planning 2018 to 2020; Vice President - Portfolio Management and Strategic Planning 2014 to 2018; Occidental Director - Portfolio Management 2012 to 2014; Occidental Director of Corporate Development and M&A 2010 to 2012; Occidental Manager of Business Development 2008 to 2010.	46
Shawn M. Kerns	Executive Vice President and Chief Operating Officer since 2021; Executive Vice President - Operations and Engineering 2018 to 2021; Executive Vice President - Corporate Development 2014 to 2018; Vintage Production California President and General Manager 2012 to 2014; Occidental of Elk Hills General Manager 2010 to 2012; Occidental of Elk Hills Asset Development Manager 2008 to 2010.	52
Michael L. Preston	Executive Vice President, Chief Strategy Officer and General Counsel since 2019; Executive Vice President, General Counsel and Corporate Secretary 2014 to 2019; Occidental Oil and Gas Vice President and General Counsel 2001 to 2014.	58
Jay A. Bys	Executive Vice President and Chief Commercial Officer since 2021; Private Energy Advisor 2019 to 2020 and 2015 to 2016; GenOn Energy and affiliate companies Chief Commercial Officer 2017 to 2018; Luminant Energy Vice President Origination and Capital Management 2007 to 2014; TXU, Enserch Energy various positions 1997 to 2007.	58
Chris D. Gould	Executive Vice President and Chief Sustainability Officer since 2021; Exelon Corporation Senior Vice President Corporate Strategy and Chief Innovation and Sustainability Officer 2010 to 2021; Exelon Corporation Vice President, Corporate Financial Planning and Analysis 2008 to 2010.	52

ITEM 11 EXECUTIVE COMPENSATION

The information required by this item is incorporated by reference from our 2023 Proxy Statement. Pursuant to the rules and regulations under the Exchange Act, the information in the *Compensation Discussion and Analysis – Compensation Committee Report* section shall not be deemed to be "soliciting material," or to be "filed" with the SEC, or subject to Regulation 14A or 14C under the Exchange Act or to the liabilities under Section 18 of the Exchange Act, nor shall it be deemed incorporated by reference into any filing under the Securities Act of 1933.

ITEM 12 SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item is incorporated by reference from our 2023 Proxy Statement. See also *Part II, Item 5 – Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities – Securities Authorized for Issuance Under Equity Compensation Plans*.

ITEM 13 CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated by reference from our 2023 Proxy Statement.

ITEM 14 PRINCIPAL ACCOUNTANT FEES AND SERVICES

Our independent registered public accounting firm is KPMG LLP, Los Angeles, CA, Auditor ID: 185.

The information required by this item is incorporated by reference from our 2023 Proxy Statement.

PART IV

ITEM 15 EXHIBITS

The agreements included as exhibits to this report are included to provide information about their terms and not to provide any other factual or disclosure information about us or the other parties to the agreements. The agreements contain representations and warranties by each of the parties to the applicable agreement that were made solely for the benefit of the other agreement parties and:

- should not be treated as categorical statements of fact, but rather as a way of allocating the risk among the parties if those statements prove to be inaccurate;
- have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
- may apply standards of materiality in a way that is different from the way the Company and investors may view materiality; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

(a) (1) and (2). Financial Statements

Reference is made to Item 8 of the Table of Contents of this report where these documents are listed.

(a) (3). Exhibits

Exhibit Number	Exhibit Description
2.1	Separation and Distribution Agreement, dated as of November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
2.2	Amended Debtors' Joint Plan of Reorganization Under Chapter 11 of the Bankruptcy Code (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed October 19, 2020 and incorporated herein by reference).
3.1	Amended and Restated Certificate of Incorporation of California Resources Corporation (filed as Exhibit 3.1 to the Registrant's Registration Statement on Form 8-A filed October 27, 2020 and incorporated herein by reference).
3.2	Certificate of Amendment of Amended and Restated Certificate of Incorporation of California Resources Corporation (filed as Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on May 6, 2022 and incorporated by reference).
3.3	Amended and Restated Bylaws of California Resources Corporation (filed as Exhibit 3.2 to the Registrant's Registration Statement on Form 8-A filed October 27, 2020 and incorporated herein by reference).
4.1	Description of Registrant's Securities (filed as Exhibit 4.1 to the Registrant's Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
4.2	Indenture, dated January 20, 2021, by and among California Resources Corporation, the Guarantors and Wilmington Trust, National Association (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed January 21, 2021 and incorporated herein by reference).
4.3	First Supplemental Indenture, dated January 20, 2021, by and among California Resources Corporation, the Guarantors, Elk Hills Power, LLC, EHP Midco Holding Company, LLC, EHP Topco Holding Company, LLC and Wilmington Trust, National Association (filed as Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed January 21, 2021 and incorporated herein by reference).
10.1	Contractors' Agreement, by and between the City of Long Beach, Humble Oil & Refining Company, Shell Oil Company, Socony Mobil Oil Company, Inc., Texaco, Inc., Union Oil Company of California, Pauley Petroleum, Inc., Allied Chemical Corporation, Richfield Oil Corporation and Standard Oil Company of California (filed as Exhibit 10.12 to Amendment No. 2 to the Registrant's Registration Statement on Form 10 filed August 20, 2014, and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.2	Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, dated November 5, 1991, by and among the State of California, by and through the State Lands Commission, the City of Long Beach, Atlantic Richfield Company and ARCO Long Beach, Inc. (filed as Exhibit 10.10 to Amendment No. 2 to the Registrant's Registration Statement on Form 10 filed August 20, 2014 and incorporated herein by reference.
10.3	Amendment to the Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, dated January 16, 2009, by and among the State of California, by and through the State Lands Commission, the City of Long Beach, and Oxy Long Beach, Inc. (filed as Exhibit 10.11 to Amendment No. 2 to the Registrant's Registration Statement on Form 10 filed August 20, 2014, and incorporated herein by reference).
10.4	Intellectual Property License Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.7 to the Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.5	Area of Mutual Interest Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.5 to the Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.6	Confidentiality and Trade Secret Protection Agreement, dated November 25, 2014, by and between Occidental Petroleum Corporation and California Resources Corporation, dated November 24, 2014 (filed as Exhibit 10.6 to the Registrant's Current Report on Form 8-K filed on December 1, 2014, and incorporated herein by reference).
10.7	Credit Agreement, dated as of October 27, 2020, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent, Collateral Agent and an Issuing Bank (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed November 2, 2020 and incorporated herein by reference).
10.8	Warrant Agreement, dated as of October 27, 2020, by and between California Resources Corporation and American Stock Transfer & Trust Company, LLC, as Warrant Agent (filed as Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed November 2, 2020 and incorporated herein by reference).
10.9	Registration Rights Agreement, dated as of October 27, 2020, by and among California Resources Corporation and the holders party thereto (filed as Exhibit 10.1 to the Registrant's Registration Statement on Form 8-A filed October 27, 2020 and incorporated herein by reference).
10.11	First Amendment to the Credit Agreement, dated as of May 7, 2021, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent, Collateral Agent and an Issuing Bank (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed May 10, 2021 and incorporated herein by reference.)
10.11	Second Amendment to the Credit Agreement, dated as of February 11, 2022, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent, Collateral Agent and an Issuing Bank (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed February 16, 2022 and incorporated herein by reference.)
10.12	Third Amendment to the Credit Agreement, dated as of April 29, 2022, by and among California Resources Corporation, as the Borrower, the credit parties party thereto, the several lenders from time to time parties thereto and Citibank, N.A. as administrative agent (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q filed May 5, 2022 and incorporated herein by reference).
	The following are management contracts and compensatory plans required to be identified specifically as responsive to Item 601(b)(10)(iii)(A) of Regulation S-K pursuant to Item 15(b) of Form 10-K.
10.13	Form of Indemnification Agreement by and between California Resources Corporation and its directors and executive officers (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed October 27, 2020 and incorporated herein by reference).
10.14	California Resources Corporation 2021 Long Term Incentive Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed January 22, 2021 and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.15	Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award for Non-Employee Directors Grant Agreement (filed as Exhibit 10.45 to the Registrant's Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
10.16	Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Term and Conditions (filed as Exhibit 10.46 to the Registrant's Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
10.17	Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Term and Conditions (filed as Exhibit 10.47 to the Registrant's Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
10.18	Form of California Resources Corporation 2021 Long Term Incentive Plan Performance Stock Unit Award Term and Conditions (filed as Exhibit 10.48 to the Registrant's Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
10.19	Employment Agreement by and between Mark A. McFarland and California Resources Corporation, dated March 22, 2021 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed March 22, 2021 and incorporated herein by reference).
10.20	Employment Agreement by and between Shawn M. Kerns and California Resources Corporation, dated June 8, 2021 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed June 11, 2021 and incorporated herein by reference).
10.21	Employment Agreement by and between Francisco J. Leon and California Resources Corporation, dated June 8, 2021 (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed June 11, 2021 and incorporated herein by reference).
10.22	Employment Agreement by and between Michael L. Preston and California Resources Corporation, dated June 8, 2021 (filed as Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q filed August 5, 2021 and incorporated herein by reference).
10.23	Employment Agreement by and between Jay A. Bys and California Resources Corporation, dated June 8, 2021 (filed as Exhibit 10.5 to the Registrant's Quarterly Report on Form 10-Q filed August 5, 2021 and incorporated herein by reference).
10.24	Employment Agreement by and between Chris Gould and California Resources Corporation, dated June 8, 2021 (filed as Exhibit 10.6 to the Registrant's Quarterly Report on Form 10-Q filed August 5, 2021 and incorporated herein by reference).
10.25*	Employment Agreement by and between Francisco J. Leon and California Resources Corporation, dated February 23, 2023.
10.26*	2023 Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Term and Conditions.
10.27*	2023 Form of California Resources Corporation 2021 Long Term Incentive Plan Performance Stock Unit Award Term and Conditions.
10.28*	Form of Cash Retention Bonus Agreement.
10.29	California Resources Corporation Employee Stock Purchase Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on May 6, 2022 and incorporated herein by reference).
21*	List of Subsidiaries of California Resources Corporation.
23.1*	Consent of Independent Registered Public Accounting Firm.
23.2*	Consent of Independent Petroleum Engineers, Ryder Scott Company, L.P.
23.3*	Consent of Independent Petroleum Engineers, Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Ryder Scott Company, L.P. Estimated Future Reserves Attributable to Certain Leasehold and Royalty Interests as of December 31, 2022.
99.2*	Netherland, Sewell & Associates, Inc. Estimated Future Reserves Attributable to Certain Leasehold and Royalty Interests as of December 31, 2022.

Exhibit Number	Exhibit Description
101.INS*	Inline XBRL Instance Document.
101.SCH*	Inline XBRL Taxonomy Extension Schema Document.
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document.
104	Cover Page Interactive Data File (formatted in inline XBRL and contained in Exhibits 101).

* - Filed herewith.

SIGNATURES

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

CALIFORNIA RESOURCES CORPORATION

February 24, 2023

By: /s/ Mark A. (Mac) McFarland

Mark A. (Mac) McFarland
President,
Chief Executive Officer and Director

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

	Title	Date
/s/ Mark A. (Mac) McFarland Mark A. (Mac) McFarland	President, Chief Executive Officer and Director	February 24, 2023
/s/ Francisco J. Leon Francisco J. Leon	Executive Vice President and Chief Financial Officer	February 24, 2023
/s/ Noelle M. Repetti Noelle M. Repetti	Senior Vice President and Controller and Principal Accounting Officer	February 24, 2023
/s/ Tiffany (TJ) Thom Cepak Tiffany (TJ) Thom Cepak	Chair of the Board	February 24, 2023
/s/ Andrew B. Bremner Andrew B. Bremner	Director	February 24, 2023
/s/ Douglas E. Brooks Douglas E. Brooks	Director	February 24, 2023
/s/ James N. Chapman James N. Chapman	Director	February 24, 2023
/s/ Nicole Neeman Brady Nicole Neeman Brady	Director	February 24, 2023
/s/ Julio M. Quintana Julio M. Quintana	Director	February 24, 2023
/s/ William B. Roby William B. Roby	Director	February 24, 2023
/s/ A. Alejandra Veltmann A. Alejandra Veltmann	Director	February 24, 2023

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Annual Meeting

California Resources Corporation's annual meeting of stockholders will be held virtually at 11:00 a.m. Pacific Time on April 28, 2023. You will not be able to attend the annual meeting physically. If you wish to attend the annual meeting, you must follow the instructions under "Attending the Annual Meeting" in the proxy statement.

Auditors

KPMG LLP, Los Angeles, California

Transfer Agent & Registrar

American Stock Transfer and Trust Company, LLC
Shareholder Services
6201 15th Avenue, Brooklyn, New York 11219
(866) 659-2647
crc@astfinancial.com
www.astfinancial.com

Investor Relations

Company financial information, public disclosures and other information are available through our website at www.crc.com. We will promptly deliver free of charge, upon request, an annual report on Form 10-K to any stockholder requesting a copy. Requests should be directed to our Investor Relations team at our corporate headquarters address or sent to CRC_IR@crc.com.

Stock Exchange Listing

California Resources Corporation's common stock is listed on the New York Stock Exchange (NYSE). The symbol is CRC.

CRC
LISTED
NYSE

Officers

Mark A. (Mac) McFarland
President and Chief Executive Officer

Jay A. Bys
Executive Vice President
and Chief Commercial Officer

Chris D. Gould
Executive Vice President
and Chief Sustainability Officer

Shawn M. Kerns
Executive Vice President
and Chief Operating Officer

Francisco J. Leon
Executive Vice President
and Chief Financial Officer

Michael L. Preston
Executive Vice President,
Chief Strategy Officer
and General Counsel

Board of Directors

Tiffany (TJ) Thom Cepak
Chair of the Board. Director since 2020

Andrew B. Bremner
Member of the Compensation Committee and
Sustainability Committee. Director since 2021

Douglas E. Brooks
Member of the Audit Committee. Director since 2020

James N. Chapman
Chair of the Compensation Committee and
Member of the Nominating and Governance Committee.
Director since 2020

Mark A. (Mac) McFarland
President, Chief Executive Officer. Director since 2020

Nicole Neeman Brady
Member of the Sustainability Committee and
Compensation Committee. Director since 2021

Julio M. Quintana
Chair of the Nominating and Governance Committee and
Member of the Audit Committee. Director since 2020

William B. Roby
Chair of the Sustainability Committee and
Member of the Audit Committee. Director since 2020

Alejandra (Ale) Veltmann
Chair of the Audit Committee and
Member of the Nominating and Governance Committee.
Director since 2021

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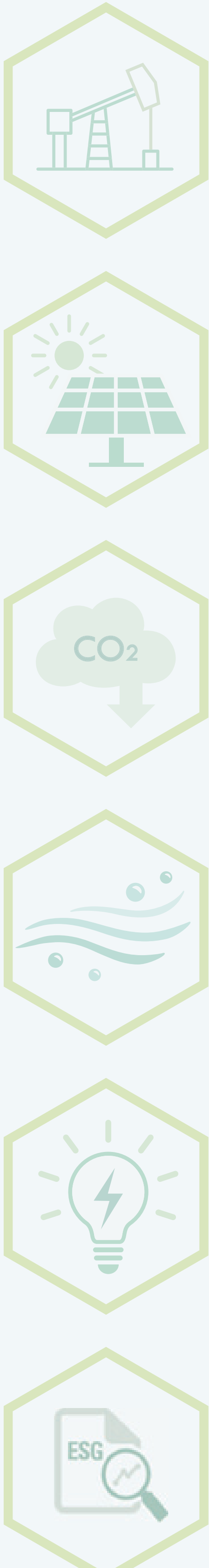
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