ANNUAL REPORT
2020

CALIFORNIA RESOURCES CORPORATION

FINANCIAL & OPERATIONAL HIGHLIGHTS

FINANCIAL HIGHLIGHTS	2020 Combined*	2019*	2018*
Dollar amounts in millions, except share and per-share amounts, as of and for the years ended December 31,			
Total Revenue	$ 1,559	$ 2,634	$ 3,064
Net Income (Loss)	$ 1,871	$ 99	$ 429
Net Income Attributable to Noncontrolling Interests	$ 105	$ 127	$ 101
Net (Loss) Income Attributable to Common Stock	$ 1,766	$ (28)	$ 328
Adjusted Net Income (Loss)(a)	$ (257)	$ 70	$ 61
Net (Loss) Income Attributable to Common Stock per Share – Diluted	–	$ (0.57)	$ 6.77
Adjusted Net Income (Loss)(a) per Share – Diluted	–	$ 1.40	$ 1.27
Net Cash Provided by Operating Activities	$ 106	$ 676	$ 461
Capital Investments	$ 47	$ 455	$ 690
Free Cash Flow(a)	$ 172	$ 269	$ (180)
Net Cash (Used) Provided by Financing Activities	$ (58)	$ (282)	$ 692
Total Assets	$ 3,074	$ 6,958	$ 7,158
Long-Term Debt, Net	$ 597	$ 5,023	$ 5,467
Equity	$ 1,182	$ (296)	$ (247)
Weighted-Average Shares Outstanding - Diluted	–	49.0	47.4
Year-End Shares	83.3	49.2	48.7

OPERATIONAL HIGHLIGHTS	2020 Combined*	2019*	2018*
Production:			
Oil (MBbl/d)	69	80	82
NGLs (MBbl/d)	13	15	16
Natural Gas (MMcf/d)	172	197	202
Total (MBoe/d)(b)	111	128	132
Average Realized Prices:			
Oil with hedge ($/Bbl)	$ 43.53	$ 68.65	$ 62.60
Oil without hedge ($/Bbl)	$ 41.89	$ 64.83	$ 70.11
NGLs ($/Bbl)	$ 27.63	$ 31.71	$ 43.67
Natural Gas ($/Mcf)	$ 2.28	$ 2.87	$ 3.00
Reserves:			
Oil (MMBbl)	313	483	530
NGLs (MMBbl)	41	52	60
Natural Gas (Bcf)	527	654	734
Total (MMBoe)(b)	442	644	712
PV-10 of Cash Flows (in billions)(a)	$ 2.4	$ 6.8	$ 9.4
Net Mineral Acreage (in thousands):			
Developed	717	673	701
Undeveloped	1,388	1,491	1,539
Total	2,105	2,164	2,240
Closing Share Price	$ 23.59	$ 9.03	$ 17.04

*Note: 2020 represents the combined successor and predecessor periods as defined in Part I - Item 7 – Basis of Presentation. 2019 and 2018 represent predecessor periods.

(a) See www.crc.com, Investor Relations for 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,

The past year was one of the most disruptive in memory. The COVID-19 global pandemic, previously unimaginable by most, upturned nearly every aspect of our lives. The steep economic downturn associated with pandemic-related lockdowns, combined with OPEC+ actions, significantly impacted California Resources Corporation (CRC).

These events of early 2020 contributed to CRC's entrance into a Chapter 11 restructuring in July to eliminate the burden of an over leveraged balance sheet. CRC emerged in October with an improved balance sheet, which we simplified further in January with our high yield offering, and we are committed to building on CRC's strong assets and repositioning the company to optimize returns to our investors.

Looking forward, CRC is shareholder-return focused and building on our strengths

1. **Asset portfolio providing resilient and predictable production.** Our assets keep on producing. The majority of our interests are in producing properties located in stacked-pay reservoirs that we believe have long-lived production profiles and repeatable development opportunities. CRC's conventional assets are also characterized by shallow base decline rates which limits the investment required to offset production declines and is a competitive advantage over many shale-based peers.
2. **Dynamic and disciplined capital investment strategy which facilitated free cash flow[1] generation in 2020.** CRC's flexible approach responds to changes in commodity pricing. As Brent oil prices fell from over $68 at the start of the year to below $20 in April, CRC cut non-discretionary capital spend and shut-in selected wells. Our decisive response to economic conditions enabled $172MM in free cash flow[1] generation for the year despite the drastic change in price environment in the first half of the year and hefty restructuring costs in the second half. CRC continuously analyzes the operating and economic performance of our assets so we can manage our portfolio for the highs and lows of the commodity price cycle.
3. **Steadfast commitment to safety and environmental, social and governance (ESG) practices.** At CRC, health and safety leads everything we do. Safeguarding people and the environment as we provide reliable energy is our number one principle. In 2020, CRC received 24 National Safety Achievement awards and set a new company safety record for our combined workforce of employees and contractors, better than the insurance and finance sectors. We earned an A- from CDP for our climate disclosure, tied for first among U.S. oil and natural gas companies, and marked two years in a row at CDP's Leadership Level.

Repositioning CRC for the future

In concert with the Board of Directors, CRC's re-aligned senior management team conducted a full-scale business review. The 2021 repositioning efforts will focus on the following:

1. **CRC will be laser-focused on core assets with the highest operating cash flow potential.** Non-core assets with insufficient cash generation will be transformed or rationalized.
2. **CRC will maintain operating and overhead cost reductions** in line with our scale and rationalized asset portfolio.
3. **CRC will practice disciplined capital investment** with a target of less than 60% of discretionary cash flow[1].
4. **CRC will maintain balance sheet strength.** In 2021, CRC will continue hedging ~80% of its production to underpin cashflows and ensure a return on capital. In addition, CRC will focus on retaining low leverage of <1.5x Net Debt/Adjusted EBITDAX[1].

A word of gratitude

I would like to thank the talented women and men of CRC for their dedication and support as we chart a new course for CRC. The reliability of our workforce has proven to be just as critical as the resilience of our assets. Our essential workers have safely and reliably met the energy needs of their fellow Californians before and during the pandemic. Just as the workforce led us through this challenging time, it will implement the actions necessary to CRC's future success. With a foundation built upon focused operations on core assets and our commitment to ESG, CRC is set up to drive both sustainable energy production and shareholder returns.

Thank you,

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

[1] Adjusted EBITDAX, discretionary cash flow, free cash flow and net debt are non-GAAP measures. See the Investor Relations page at www.crc.com for additional information about these non-GAAP measures and reconciliations of non-GAAP measures to their closest GAAP equivalents.

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, 2020

☐ **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.)

27200 Tourney Road, Suite 200
Santa Clarita, California 91355
(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. ☐

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, 2020: $59 million.

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 February 28, 2021, there were 83,319,660 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement to be filed within 120 days after December 31, 2020 with the Securities and Exchange Commission in connection with the registrant's 2021 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

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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 ample, 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 making value-based capital investments. 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.

Our average net production was 111 thousand barrels of oil equivalent per day (MBoe/d) for the year ended December 31, 2020. We have the largest privately held mineral acreage position in the state, consisting of approximately 2.1 million net mineral acres spanning four of California's major oil and natural gas basins. As of December 31, 2020, our proved reserves totaled an estimated 442 million barrels of oil equivalent (MMBoe), of which 313 million barrels (MMBbl) were crude oil and condensate reserves, 41 MMBbl were NGL reserves and 527 billion cubic feet (BcF), or 88 MMBoe, were natural gas reserves. 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 gas industry.

Reorganization Under Chapter 11 and Emergence from Bankruptcy Proceedings and Subsequent Refinancing

A severe industry downturn and commodity price collapse caused by the global Coronavirus Disease 2019 (COVID-19) pandemic and the over-supply resulting from a price war between members of the Organization of the Petroleum Exporting Countries (OPEC) and Russia and other allied producing countries led us to file voluntary petitions for relief under a Chapter 11 proceeding on July 15, 2020 (Chapter 11 Cases) in the United States Bankruptcy Court for the Southern District of Texas, Houston Division (Bankruptcy Court).

We emerged from bankruptcy on October 27, 2020 with a new board of directors, new equity owners and a significantly improved financial position. Under the plan of reorganization approved by the Bankruptcy Court (the Plan), all of our outstanding pre-emergence indebtedness under our credit facilities and senior notes was cancelled. At emergence, we entered into a new revolving credit facility with a $1.2 billion borrowing base and $540 million of lender commitments (Revolving Credit Facility). Our post-emergence capital structure also included a $200 million second lien term loan (Second Lien Term Loan), and $300 million of secured notes due 2027 issued by our wholly-owned subsidiary in connection with our acquisition of our partner's interest in our Elk Hills Power joint venture (EHP Notes).

On January 20, 2021, we completed an offering of $600 million aggregate principal amount of 7.125% senior notes due 2026 (Senior Notes). We used the net proceeds to repay in full our Second Lien Term Loan and EHP Notes, with the remainder of the net proceeds used to repay a portion of the outstanding borrowings under our Revolving Credit Facility.

For information on the significant transactions which occurred upon our emergence from Chapter 11, see *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Basis of Presentation and Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Chapter 11 Proceedings*. For more information on our debt, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Debt.*

Board of Directors

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. The new directors have different backgrounds, experiences and perspectives from those individuals who previously served on our Board and, thus, have different views on the issues that will determine our strategic direction. In addition, our former Chief Executive Officer and director Todd A. Stevens departed on December 31, 2020. Our Board is led by Mark A. (Mac) McFarland, our Chairman and interim Chief Executive Officer, and James N. Chapman, our Lead Independent Director.

The Board has initiated a search process for our next Chief Executive Officer and a strategic review of our business. As a result of this review, we have streamlined our organization and are repositioning ourselves as a low-cost operator. We intend to pursue asset divestitures to focus our operations on core fields that we expect will further lower our costs and enhance free cash flow.

Fresh Start Accounting

We adopted fresh start accounting in connection with our 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 and (2) the reorganization value of our assets immediately prior to the confirmation of the Plan was less than our post-petition liabilities and allowed claims. 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.

Under fresh start accounting, the reorganized entity is considered a new reporting entity for financial reporting purposes. As a result, the reorganization value of the emerging entity is assigned to individual assets and liabilities based on their estimated relative fair values. The reorganization value was derived from our enterprise value, which was the estimated fair value of our long-term debt and shareholder's equity at emergence from bankruptcy. 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. Based on our internal estimates and assumptions, we estimated our enterprise value to be $2.5 billion, at about the mid-point of the range approved by the Bankruptcy Court. For additional information on the effects of fresh start accounting, see *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Basis of Presentation* and *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Fresh Start Accounting.*

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 transactions between October 28, 2020 and October 31, 2020 were not material and the use of an accounting convenience date was appropriate. As such, fresh start accounting was reflected in our consolidated balance sheet as of October 31, 2020. 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 ending on or prior to October 31, 2020 and references to "Successor" refer to the Company for periods subsequent to October 31, 2020.

Business Strategy

Under the leadership of our new Board appointed in October 2020, we have implemented a business strategy with the following key priorities:

- **Deliver value and drive free cash flow generation.**

  With a right-sized balance sheet, a leaner organization and a lower cost base, we believe we are well positioned to compete across a wide range of potential commodity price environments. Our asset base – with its low decline rates and efficient capital requirements – provides significant advantages. Our capital program is designed to be funded from operating cash flow and improved margins. We intend to focus on crude oil projects, thus over time improving our margins. We believe this operating model, coupled with premium pricing on our products, as compared to U.S. benchmarks, position us as a leading exploration and production (E&P) company to deliver operationally and financially.

- **Maintain our commitment to safety and sustainability and show leadership on environmental, social and governance (ESG) practices in the E&P space**.

  We are focused on our ESG performance while improving overall corporate transparency and highlighting the positive impact we have on communities in which we operate. Our 2030 Sustainability Goals and our ongoing sustainability strategy are intended to align with the climate goals of California, which has committed to adhere to the Paris Agreement, which entered into force on November 4, 2016 (the Paris Agreement). We publish a sustainability report annually that documents our proven track record of safety, technological innovation and operational excellence and dedication to our ESG policies. As part of this strategy, our 2020 compensation metrics for our management team included specific ESG targets for safety, environmental stewardship and sustainability project milestones.

- **Maintain dynamic capital allocation process to drive cash flow generation across a range of commodity price environments.**

  In the current Brent oil price environment, a substantial portion of our expected capital expenditures will be allocated to oil driven workover and shallow drilling, which we expect to generate strong margins and cash flow with short nominal payback. If Brent oil prices decrease, we retain the flexibility to reduce capital spending, while benefiting from the downside protection from our hedges, in order to preserve free cash flow. If Brent oil prices increase, we would consider incremental investment to further enhance value and increase long-term free cash flow generation.

- **Continue to pursue a predictable, advantaged and integrated asset base.**

  Our diverse, lower-decline and lower-risk production portfolio in prolific conventional basins with a high net revenue interest provides a higher level of predictability. Our integrated and owned infrastructure assets further enhance margins and provide operational control. Our asset characteristics and integrated operations exemplify our strategy of maintaining low business and execution risk. Our operations are further advantaged by our location in California, a leading economy within the United States. The deficit in California’s energy supply, combined with the local infrastructure and transportation systems constraints, provides premium realizations on all of our products as compared to U.S. benchmarks.

- **Maintain operational excellence while reducing our cost structure.**

  We expect to further improve our performance and execution by continuing to lower operating costs and increase drilling, completion and related facilities capital efficiencies. We reduced our operating expenses to an average of $55 million per month in the fourth quarter of 2020. We have retooled our organization for the current commodity price environment as we have steadily reduced general and administrative (G&A) expenses from approximately $300 million in 2019 to approximately $250 million in the twelve months ended December 31, 2020.

- **Preserve balance sheet strength with a disciplined approach to capital allocation and a robust hedging program**.

  Our capital allocation priorities are guided by our focus on maximizing the value of our assets while protecting our balance sheet, maintaining mechanical integrity of our infrastructure and maintaining or, in a higher commodity price environment, growing our base production while generating free cash flow. We target a capital budget that is funded from expected cash flows. As part of this strategy, we typically utilize a combination of derivative instruments to protect our cash flows. We intend to maintain low leverage going forward. Additionally, we are targeting a net debt to adjusted EBITDAX ratio of less than 1.5x and are committed to maintaining a strong liquidity position.

Operations

We have the largest privately held mineral acreage position in California, consisting of approximately 2.1 million net mineral acres spanning four of California's major oil and natural gas basins. Our operated asset base spans 130 distinct fields with approximately 12,000 operated wells. Our average net production of approximately 111 MBoe/d (62% oil) for the year ended December 31, 2020. Our average net revenue interest was approximately 87% as of December 31, 2020. The following table highlights key information about our operations as of and for the year ended December 31, 2020:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total Operations
Mineral Acreage					
Net mineral acreage (thousands)	1,347	30	225	503	2,105
Average net mineral acreage held in fee (%)	73%	47%	81%	37%	65%
Number of fields	44	6	27	53	130
Average net revenue interest (%)[(a)]	90%	80%	89%	80%	87%
Average drilling rigs[(b)]	2	—	—	—	2
Net wells drilled and completed[(b)]	4.0	4.5	—	0.4	8.9
Proved reserves					
Oil (MMBbl)	199	104	10	—	313
NGLs (MMBbl)	40	—	1	—	41
Natural gas (Bcf)	468	7	7	45	527
Total (MMBoe)	317	105	12	8	442
Oil percentage of proved reserves	63%	99%	83%	—%	71%
Production					
Total net production (MMBoe)	29	9	1	1	40
Average daily net production (MBoe/d)	79	24	4	4	111
Oil percentage of net production	53%	100%	75%	—%	62%
Reserves to production ratio (years)[(c)]	10.9	11.7	12.0	8.0	11.1

Note: MMBbl refers to millions of barrels; Bcf refers to billions of cubic feet; MMBoe refers to millions of barrels of oil equivalent; and MBoe/d refers to thousands of barrels of oil equivalent (Boe) per day. Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of natural gas to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

(a) The average net revenue interest represents our interest in production after considering royalties and similar burdens and third-party working interests.

(b) Beginning in March 2020, as a result of the low commodity price environment, we reduced our operating costs and planned capital expenditures to those necessary to maintain mechanical integrity of our facilities to operate them in a safe and environmentally responsible manner. We also decreased the number of drilling rigs we then operated throughout the state to zero.

(c) Calculated as total proved reserves as of December 31, 2020 divided by total production for the year ended December 31, 2020.

San Joaquin Basin

The San Joaquin basin contains some of the largest oil fields in the United States based on cumulative production and proved reserves. Commercial petroleum development in the basin began in the 1800s. The basin contains multiple stacked formations throughout its areal extent, and we believe that the San Joaquin basin provides appealing opportunities for field 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. Approximately 75% of California's total daily oil production for 2018 was produced in the San Joaquin basin, according to CalGEM.

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 one of the largest fields in the continental U.S.

At Elk Hills we also operate efficient natural gas processing facilities, including a state-of-the-art 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 have a large ownership interest in several of the largest existing oil fields in the San Joaquin basin including Buena Vista and Coles Levee. We have also been successfully developing steamfloods in our Kern Front operations.

We believe our extensive 3D seismic library, which covers approximately 800,000 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 and further exploration.

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. The basin contains multiple stacked formations throughout its depths, and we believe that the Los Angeles basin provides a considerable inventory of existing field re-development opportunities as well as new play discovery potential. Large active oil fields include the Wilmington and Huntington Beach fields, where we have significant operations.

The Wilmington field has been one of the largest fields in the continental U.S. 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.

Ventura Basin

The Ventura Basin is the oldest operating oil basin in California extending from northern Los Angeles County to the coastal area of Ventura. The earliest discoveries were mines dug into hillsides to mine active oil seeps. The first commercial oil well started in 1866. The entire sedimentary section is productive at various locations, and most reservoirs are sandstones with favorable porosity and permeability. As of December 31, 2020, we operated more than 20 oil fields in this historic and prolific basin. The basin contains multiple stacked formations and provides an appealing inventory of existing field re-development opportunities, as well as new exploration potential.

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.

Mineral Acreage

The following table summarizes our gross and net developed and undeveloped mineral acreage as of December 31, 2020.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in thousands)		
Developed[a]					
Gross[b]	438	21	60	265	784
Net[c]	398	16	58	245	717
Undeveloped[d]					
Gross[b]	1,171	17	201	317	1,706
Net[c]	949	14	167	258	1,388
Total					
Gross[b]	1,609	38	261	582	2,490
Net[c]	1,347	30	225	503	2,105

(a) Mineral acres spaced or assigned to productive wells.
(b) Total number of mineral acres in which interests are owned.
(c) Net mineral acreage includes acreage reduced to our fractional ownership interest and interests under PSC-type contracts.
(d) 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.

Approximately 65% of our total net mineral interest position is held in fee and the remainder is leased. Of our leased acreage, approximately 49% 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 ten 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.

Approximately 58,000 net mineral acres will expire in 2021, 119,000 net mineral acres will expire in 2022 and 57,000 net mineral acres will expire in 2023 if production is not established and we take no other action to extend the terms of the leases. These leases expiring in the next three years represented 17% of our total net undeveloped acreage at December 31, 2020 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 we will need to do so in the future.

Production, Price and Cost History

The following table sets forth information regarding our production, average realized and benchmark prices and operating costs per Boe for the years ended December 31, 2020, 2019 and 2018. For additional information on production and prices, see information set forth in *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Production and Prices*.

	Successor	Predecessor	Combined	Predecessor	
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year Ended December 31, 2020	Year Ended December 31, 2019	Year Ended December 31, 2018
Average daily production					
Oil (MBbl/d)	63	70	69	80	82
NGLs (MBbl/d)	12	13	13	15	16
Natural gas (MMcf/d)	165	174	172	197	202
Total daily production (MBoe/d)(a)(b)	103	112	111	128	132
Total production (MMBoe)(a)(b)	6	34	40	47	48
Average realized prices					
Oil with hedge ($/Bbl)	$ 45.37	$ 43.19	$ 43.53	$ 68.65	$ 62.60
Oil without hedge ($/Bbl)	$ 45.65	$ 41.21	$ 41.89	$ 64.83	$ 70.11
NGLs ($/Bbl)	$ 38.00	$ 25.70	$ 27.63	$ 31.71	$ 43.67
Natural gas without hedge ($/Mcf)	$ 3.21	$ 2.11	$ 2.28	$ 2.87	$ 3.00
Average benchmark prices					
Brent oil ($/Bbl)	$ 47.10	$ 42.43	$ 43.21	$ 64.18	$ 71.53
WTI oil ($/Bbl)	$ 44.21	$ 38.44	$ 39.40	$ 57.03	$ 64.77
NYMEX gas ($/MMBtu)	$ 2.86	$ 1.95	$ 2.10	$ 2.67	$ 2.97
Operating costs per Boe(b)					
Operating costs	$ 18.19	$ 14.95	$ 15.45	$ 19.16	$ 18.88
Operating costs, excluding effects of PSC-type contracts(c)	$ 16.86	$ 14.14	$ 14.56	$ 17.70	$ 17.47

Note: Bbl refers to barrels; MBbl/d refers to thousands of barrels per day; MMcf/d refers to millions of cubic feet per day; MMBtu refers to millions of British Thermal Units.

(a) We temporarily shut in production of 3 MBoe/d in 2020, which negatively impacted our production compared to 2019. Additionally, our divestiture of a 50% working interest in certain zones within our Lost Hills field resulted in a decrease of approximately 2 MBoe/d beginning in the second quarter of 2019. Our PSC-type contract positively impacted our oil production in 2020 by approximately 3 MBoe/d compared to 2019. PSC-type contracts had no impact on our oil production in 2019 compared to 2018.

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

(c) The reporting of our PSC-type contracts 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 operating costs after adjusting for the excess costs attributable to PSC-type contracts.

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

	Elk Hills			Wilmington		
	2020	2019	2018	2020	2019	2018
Average daily production						
Oil (MBbl/d)	18	22	22	21	20	21
NGLs (MBbl/d)	10	12	12	—	—	—
Natural gas (MMcf/d)	90	103	108	1	1	1
Total daily production (MBoe/d)	43	51	52	21	20	21

Oil, NGLs and natural gas are commodities, and the prices we receive for our production are largely a function of market supply and demand. Product prices are affected by a variety of factors, including changes in domestic and global supply and demand; domestic and global inventory levels; political and economic conditions; 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 regulations, 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, along with market perceptions with respect to all of these factors. We have a hedging program to help protect our cash flow, operating margin and capital program, while maintaining adequate liquidity.

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. The measures taken to address the recent industry downturn demonstrate that we can significantly reduce our operating costs in response to prevailing market conditions. We further believe that a significant portion of our operating costs are variable over the lifecycle of our fields. We actively manage our fields to optimize production and minimize costs in a safe and responsible manner throughout their lifecycles.

Our share of production and reserves from operations in the Wilmington field in the Los Angeles basin is subject to contractual arrangements similar to PSC-type contracts 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 PSC-type contracts represented 18% of our production for the year ended December 31, 2020.

In addition, in line with industry practice for reporting PSC-type contracts, 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 PSC-type contracts. 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.

Estimated Proved Reserves, Future Net Cash Flows and Drilling Locations

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, 2020. 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 $41.77 per barrel was adjusted for gravity, quality and transportation costs. For natural gas volumes, the average NYMEX gas price of $1.98 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, 2020 were $42.35 per barrel for oil, $26.42 per barrel for NGLs and $2.28 per Mcf for natural gas.

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

	As of December 31, 2020				
	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Proved developed reserves					
Oil (MMBbl)	171	85	10	—	266
NGLs (MMBbl)	38	—	1	—	39
Natural Gas (Bcf)	413	6	7	34	460
Total (MMBoe)(a)(b)	278	86	12	6	382
Proved undeveloped reserves					
Oil (MMBbl)	28	19	—	—	47
NGLs (MMBbl)	2	—	—	—	2
Natural Gas (Bcf)	55	1	—	11	67
Total (MMBoe)(b)	39	19	—	2	60
Total proved reserves					
Oil (MMBbl)	199	104	10	—	313
NGLs (MMBbl)	40	—	1	—	41
Natural Gas (Bcf)	468	7	7	45	527
Total (MMBoe)(b)	317	105	12	8	442

(a) As of December 31, 2020, approximately 27% of proved developed oil reserves, 13% of proved developed NGLs reserves, 16% of proved developed natural gas reserves and, overall, 24% 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) Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of gas to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

Changes to Proved Reserves

There were material changes to our December 31, 2020 reserve estimates when compared to our December 31, 2019 reserve estimates due to factors including (i) price-related revisions, (ii) performance-related revisions and (iii) booking of certain proved undeveloped reserves as part of fresh start accounting which were previously written off under the SEC's five year rule.

The components of the changes to our proved reserves during the year ended December 31, 2020 were as follows:

	San Joaquin Basin	Los Angeles Basin[(a)]	Ventura Basin	Sacramento Basin	Total
			(in MMBoe)		
Balance at December 31, 2019	417	170	42	15	644
Revisions related to price	(38)	(20)	(14)	—	(72)
Revisions related to performance	(23)	(19)	(14)	(5)	(61)
Removal of proved undeveloped reserves	(27)	(23)	(1)	(1)	(52)
Extensions and discoveries	19	6	—	—	25
Divestitures	(2)	—	—	—	(2)
Production	(29)	(9)	(1)	(1)	(40)
Balance at December 31, 2020	317	105	12	8	442

Note: Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of natural gas and one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

(a) Includes proved reserves related to PSC-type contracts of 85 MMBoe and 125 MMBoe at December 31, 2020 and 2019, respectively.

Price-related revisions – 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 oil prices, partially offset by our lower operating costs.

Performance-related revisions – 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 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 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.

Removal of proved undeveloped reserves – 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.

Proved Undeveloped Reserves

The total changes to our proved undeveloped reserves during the year ended December 31, 2020 were as follows:

	San Joaquin Basin	Los Angeles Basin[a]	Ventura Basin	Sacramento Basin	Total
			(in MMBoe)		
Balance at December 31, 2019	88	47	13	3	151
Revisions related to price	(14)	(8)	(6)	—	(28)
Revisions related to performance	(13)	(3)	(6)	—	(22)
Removal of proved undeveloped reserves	(27)	(23)	(1)	(1)	(52)
Extensions and discoveries	17	6	—	—	23
Improved recovery	—	—	—	—	—
Divestitures	—	—	—	—	—
Transfers to proved developed reserves	(12)	—	—	—	(12)
Balance at December 31, 2020	39	19	—	2	60

Note: Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of natural gas and one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

Price-related revisions – We had negative price-related revisions of 28 MMBoe primarily resulting from a lower commodity price environment in 2020 compared to 2019.

Performance-related revisions – We had 22 MMBoe of net negative performance-related revisions. As a result of underperformance of certain producing wells, proved undeveloped projects were revised downward by 24 MMBoe. The performance of producing wells can impact undeveloped projects in several ways such as estimation of analogous type curves, constraining infrastructure capacity and field curtailment due to economic limits. A significant factor was a reduction in our capital program due to the low commodity price environment and constraints during the bankruptcy process. This led to a steepening of base decline due to injection curtailment, capacity limitations and reduced well maintenance. We also added 2 MMBoe primarily related to better-than-expected performance.

Removal of proved undeveloped reserves – We removed a total of 52 MMBoe of proved undeveloped reserves, all of which were no longer prioritized in our development plans because they did not meet internal investment thresholds at lower SEC prices. The majority of these revisions are located in the San Joaquin and Los Angeles basins.

Extensions and discoveries – We added 23 MMBoe of proved undeveloped reserves through extensions and discoveries, approximately half of which resulted from the booking of proved undeveloped reserves in connection with fresh start accounting. The remainder of additions resulted from a very limited drilling program concentrated on deeper wells in the San Joaquin basin and our low cost capital workover program in our shallow waterflood fields resulted in favorable results.

Transfers to proved developed reserves – We converted 12 MMBoe of proved undeveloped reserves to proved developed reserves in the San Joaquin basin. This resulted in a conversion rate of approximately 8% of our beginning-of-year proved undeveloped reserves, with an investment of approximately $10 million of drilling and completion capital, to the proved developed category.

Our year-end development plans and associated proved undeveloped reserves are consistent with SEC guidelines for development within five years. We believe we will have sufficient capital to develop all year-end 2020 proved undeveloped reserves within five years.

PV-10, Standardized Measure and Reserve Replacement Ratio

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, 2020 (in millions)
Standardized measure of discounted future net cash flows	$ 1,932
Present value of future income taxes discounted at 10%	494
PV-10 of cash flows[(a)]	$ 2,426

(a) The average realized prices for estimating our PV-10 of cash flow as of December 31, 2020 were $42.35 per barrel for oil, $26.42 per barrel for NGLs and $2.28 per Mcf for natural gas.

Reserves Evaluation and Review Process

Our estimates of proved reserves and associated discounted future net cash flows as of December 31, 2020 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. Production rate forecasts are derived using a number of methods, including estimates from decline-curve analysis, type-curve analysis, material balance calculations, which consider the volumes of substances replacing the volumes produced and associated reservoir pressure changes, 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. 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.

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, Reserves and Corporate Development has primary responsibility for overseeing the preparation of our reserves estimates. She has 20 years of experience as an energy sector engineer including as a Senior Reservoir Engineer with Ryder Scott Company, L.P. (Ryder Scott). She is a member of the Society of Petroleum Engineers (SPE) for which she served as past chair of the U.S. Registration Committee. She holds a Master of Business Administration from the Massachusetts Institute of Technology, a Master of Engineering in Petroleum Engineering from the University of Houston and a Bachelor of Science from the University of Florida. She is also a registered Professional Engineer in the state of Texas.

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 2020. 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, 2020, Ryder Scott audited 53% of our total proved reserves. NSAI audited 31% of our total proved reserves. Over 95% of our total 2020 proved reserves were audited by independent auditors at some time during the four-year period ended December 31, 2020.

Our independent reserve engineers examined the assumptions underlying our reserves estimates, adequacy and quality of our work product, and estimates of future production rates, net revenues, and the present value of such net revenues. 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 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, 2020, 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 40 years of petroleum engineering experience, the majority of which has been in the estimation and evaluation of reserves. He serves on the Ryder Scott Board of Directors and is a registered Professional Engineer in the state of Texas.

NSAI qualifications – The primary technical engineer primarily responsible for our audit has 20 years of petroleum engineering experience, with the majority spent evaluating California properties, and is a registered Professional Engineer in the state of Texas.

Drilling Locations

The table below sets forth our total gross identified proved drilling locations by basin as of December 31, 2020, excluding injection wells.

	Proved Drilling Locations
San Joaquin Basin	451
Los Angeles Basin	128
Ventura Basin	—
Sacramento Basin	12
Total Proved Drilling Locations	**591**

Based on our reserves report as of December 31, 2020, we have 591 gross drilling locations attributable to our proved undeveloped reserves. We use production data and experience gained from our development programs to identify and prioritize this proven drilling inventory. These drilling locations are included in our reserves only after we have adopted a development plan to drill them within a five-year time frame of the original reserve booking. As a result of rigorous technical evaluation of geologic and engineering data, we can estimate with reasonable certainty that reserves from these locations will be commercially recoverable in accordance with SEC guidelines. Management considers the availability of local infrastructure, drilling support assets, state and local regulations and other factors it deems relevant in determining such locations.

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. Net wells represent wells reduced to our fractional interest.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total Net Wells
2020					
Productive					
Exploratory	—	—	—	—	—
Development	4.0	4.5	—	0.4	8.9
2019					
Productive					
Exploratory	0.3	—	—	—	0.3
Development	117.5	25.2	2.0	2.4	147.1
2018					
Productive					
Exploratory	0.3	—	—	—	0.3
Development	127.0	48.2	3.2	—	178.4
Dry					
Exploratory	1.3	—	0.3	—	1.6
Development	—	—	—	—	—

We had one steamflood well, on a gross basis, which was pending completion in the San Joaquin basin as of December 31, 2020 and is not included in the table above.

Productive Wells

Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Our average working interest in our producing wells is 88%. 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, 2020, excluding wells that have been idle for more than five years:

	As of December 31, 2020			
	Productive Oil Wells		Productive Natural Gas Wells	
	Gross[(a)]	Net[(b)]	Gross[(a)]	Net[(b)]
San Joaquin Basin	8,099	7,113	152	148
Los Angeles Basin	1,723	1,634	—	—
Ventura Basin	755	743	—	—
Sacramento Basin	—	—	828	761
Total	10,577	9,490	980	909
Multiple completion wells included in the total above	177	158	42	37

(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 a robust prospect inventory of onshore conventional plays. California basins have generated billions of barrels of oil and trillions of cubic feet of natural gas and have established production from over 400 identified reservoir intervals in both structural and stratigraphic trap configurations, from depths of less than 1,000 feet to greater than 15,000 feet. Historical industry activity has focused on the primary and secondary development of known hydrocarbon accumulations, many of which were discovered over a century ago. We have a ranked near-field portfolio of over 150 exploration prospects across the San Joaquin, Sacramento and Ventura basins, as well as significant land positions in under-explored hydrocarbon reservoirs in each of California's four major oil and natural gas basins.

Our 3D seismic library covers approximately 4,950 square miles, representing approximately 90% of the 3D seismic data available in California, along with 12,000 square miles of 2D data. We have developed unique, proprietary stratigraphic and structural models of the subsurface geology and hydrocarbon potential in each of the four basins in which we operate. We have successfully implemented various exploration, drilling, completion and enhanced recovery technologies to increase recoveries, growth and value from our portfolio.

Human Capital

We believe our employees are our most important asset and, guided by our core values, strive to provide a safe and healthy workplace. We provide development opportunities and financial rewards so that our employees are engaged and focusing on providing safe, affordable, abundant energy for the people of California.

As of the date of this report, we had approximately 1,000 employees, all in the United States. Approximately 60 of our employees are covered by a collective bargaining agreement. We also utilize the services of many third party contractors throughout our operations.

Core Values

We believe our core values of Character, Responsibility and Commitment and our comprehensive business and ethical conduct policies sustain and enhance 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.

Safe and Healthy Workplace

Our unwavering commitment to health, safety and the environment permeates all of our operations. Each year, we set a threshold injury and illness incidence rate 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.

We promote the health and well-being of our employees by providing comprehensive health benefits and time off for illness and vacation.

Development Opportunities

Employee development opportunities are provided to enhance leadership development and expand career opportunities. A copy of our policies were provided to all employees, who also undergo mandatory annual training on the policies. Employer sponsored 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 our employees and those of our suppliers, vendors and joint ventures.

Financial Rewards

We provide our employees industry competitive base wages and incentive compensation opportunities, as well as comprehensive health and retirement benefits; life, disability and accident insurance coverages; and employee assistance and wellness programs to promote financial stability and healthy lifestyles.

Engagement

We survey our employees annually to assess engagement levels and drivers to determine areas to focus on going forward. The results of the engagement surveys are reviewed by senior management and the Board.

Organization Changes

During the course of the Chapter 11 Cases, we evaluated the structure of our workforce and implemented organizational changes in August 2020 that resulted in a reduction of our headcount from 1,250 to approximately 1,100 employees. Subsequent to our emergence from bankruptcy, we took steps to further align our cost structure to focus on our core assets and on becoming a low-cost operator. We reduced the size of our management team in January 2021 and then realigned several functions, which resulted in additional headcount and cost reductions. During the first quarter of 2021, we reduced our headcount to approximately 1,000 employees. We believe the steps taken improved and strengthened our business after we emerged from bankruptcy. In addition, on December 31, 2020, our former Chief Executive Officer and director Todd A. Stevens departed and Mark A. (Mac) McFarland was appointed our Interim Chief Executive Officer.

These personnel-related changes are expected to reduce the compensation expense component of our 2021 operating expenses by approximately $15 million per year and general and administrative expenses by approximately $50 million per year from our 2020 levels.

Marketing Arrangements

Crude Oil – We sell nearly all of our crude oil into the California refining markets, which offer favorable pricing for comparable grades relative to other U.S. regions. 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.

Although California state policies actively promote and subsidize renewable energy, the demand for oil and natural gas in California remains strong. California is heavily reliant on imported sources of energy, with approximately 70% of oil and 90% of natural gas consumed in 2019 imported from outside the state. Nearly all of the imported oil arrives via supertanker, mostly from foreign locations. As a result, California refiners have typically purchased crude oil at international waterborne-based Brent prices. We believe that the limited crude transportation infrastructure from other parts of the U.S. into California will continue to contribute to higher realizations 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 markets on a daily basis at average monthly index pricing. 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 enjoy higher netback pricing relative to out-of-state producers due to lower transportation costs on the delivery of our natural gas. Changes in natural gas prices have a smaller impact on our operating results than changes in oil prices as only approximately 25% of our total equivalent production volume and even a smaller percentage of our revenue is from 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 the operating costs but have a net negative effect on our financial results.

We currently have transportation capacity contracts to transport all of our natural gas volumes for the next three years. We sell virtually all of our natural gas production under individually negotiated contracts using market-based pricing.

NGLs – NGL price realizations are related to the supply and demand for the products making up these liquids. Some of them more typically correlate to the price of oil while others are affected by natural gas prices as well as the demand for certain chemical products for which they are used as feedstock. In addition, infrastructure constraints and seasonality can magnify price volatility.

Our earnings are also affected by the performance of our complementary 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 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 pipeline transportation contract for 6,500 barrels per day of NGLs. Our contract to transport NGLs requires us to cash settle any shortfall between the committed quantities and volumes actually shipped. We have thus far met all our shipping commitments under this contract. In connection with another pipeline delivery contract that we assumed from Occidental, we made a one-time deficiency payment of $20 million in April 2020 when the contract expired. We sell virtually all of our NGLs using index-based pricing. Our NGLs are generally sold pursuant to contracts that are renewed annually. Approximately 30% of our NGLs are sold to export markets.

Electricity – Part of the electrical output of the Elk Hills power plant is used by Elk Hills and other nearby fields, which reduces field operating costs and provides a reliable source of power. We sell the excess electricity generated to a local utility, other third parties and the grid. The power sold to the utility is subject to agreements through the end of 2023, which include a monthly capacity payment plus a variable payment based on the quantity of power purchased each month. Any excess capacity not sold to other third parties is sold to the wholesale power market. The prices obtained for excess power impact our earnings but generally by an relatively small amount.

Delivery Commitments

We have short-term commitments to certain refineries and other buyers to deliver oil, natural gas and NGLs. As of December 31, 2020, we had oil delivery commitments of 41 MBbl/d through March 2021, NGL delivery commitments of 11 MBbl/d through April 2021 and natural gas delivery commitments of 32 MMcf/d through the end of 2021. 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 are index-based contracts with prices set at the time of delivery.

Hedging

Our hedging strategy seeks to mitigate our exposure to commodity price volatility and ensure our financial strength and liquidity by protecting our cash flows. In addition, our Revolving Credit Facility requires us to maintain hedges on a minimum amount of crude oil production, determined semi-annually, of no less than (i) 75% of our reasonably anticipated oil production from our proved reserves for the first 24 months after the closing of the Revolving Credit Facility, which occurred upon emergence from bankruptcy, and (ii) 50% of our reasonably anticipated oil production from our proved reserves for a period from the 25th month through the 36th month after the same date. The Revolving Credit Facility specifies the forms of hedges and prices (which can be prevailing prices) that must be used for a portion of those hedges.

We must also maintain acceptable commodity hedges for no less than 50% of the reasonably anticipated oil production from our proved reserves for at least 24 months following the date of delivery of each reserve report. We may not hedge more than 80% of reasonably anticipated total forecasted production of crude oil, natural gas and natural gas liquids from our oil and gas properties for a 48-month period.

Refer to *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources* for current 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.

We had three customers that individually accounted for at least 10%, and collectively accounted for 53%, of our sales (before the effects of hedging) during 2020. These purchasers are in the crude oil refining industry. In light of the ongoing energy deficit in California and the 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 financial condition or results of operations.

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 8 Debt.*

Competition

We encounter strong competition from numerous parties in the oil and natural gas industry doing business in California, ranging from small independent producers to major international oil companies. The oil market in California is a captive market with no interstate crude pipelines and only limited rail access and unloading capacity for refineries. California imports approximately 70% of the oil it consumes and virtually all of that arrives from waterborne sources. Our proximity to the California refineries gives us a competitive advantage through lower transportation costs. Further, California refineries are generally designed to process crude with similar characteristics to the 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. However, the California energy industry has experienced only limited cost inflation in recent years due to excess capacity in the service and supply sectors. At current commodity price levels, we expect limited cost inflation in 2021. Further, 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 indirect competition from alternative energy sources, including wind and solar power. Competitive conditions could be affected by future legislation and regulation as California continues to develop renewable energy and implements climate-related policies.

Infrastructure

We own or control a network of strategically placed infrastructure that integrates with and complements our operations to maximize the value generated from our production. The significant scale of our integrated infrastructure helps us connect to third-party transportation pipelines, providing us with a competitive advantage by reducing our operating costs. We maintain a rigorous maintenance program, extending the life of our infrastructure and targeting safety and environmental stewardship. Our infrastructure includes the following:

Description	Quantity	Unit[(a)]	Capacity		
			San Joaquin Basin	Other Basins	Total
Gas Processing Plants	8	MMcf/d	525	40	565
Power Plants	3	MW	595	48	643
Steam Generators/Plants	>30	MBbl/d	150	—	150
Compressors	>300	MHp	320	31	351
Water Management Systems		MBw/d	1,900	2,055	3,955
Water Softeners	16	MBw/d	125	—	125
Oil and NGL Storage		MBbls	408	271	679
Gathering Systems		Miles			>8,000

(a) MW refers to megawatts of power; MBbl/d refers to thousand barrels of steam per day; MHp refers to thousand horsepower; MBw/d refers to thousand barrels of water per day; MBbl refers to thousands of barrels.

Natural Gas Processing

We believe we own or control the largest gas processing system in California. In the San Joaquin basin, the Elk Hills cryogenic gas plant has a capacity of 200 MMcf/d of inlet gas, bringing our total processing capacity in the basin to over 525 MMcf/d, which includes our two low temperature separation plants used as backup facilities. We also own and operate a system of natural gas processing facilities in the Ventura basin that are capable of processing our equity and third-party wellhead gas from the surrounding areas. 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.

Electricity

Our 550-megawatt combined-cycle Elk Hills power plant, located adjacent to the Elk Hills natural gas processing facility, 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 our operations and our subsidiary sells the excess to the grid and to a local utility. The Elk Hills power plant also provides primary steam supply to our cryogenic gas plant. We also operate intermittently a 45-megawatt cogeneration facility at Elk Hills that provides additional flexibility and reliability to support field operations. Within our Long Beach operations in the Los Angeles basin, we operate a 48-megawatt power generating facility that provides over 40% of our Long Beach operation's electricity requirements. All of these facilities are integrated with our operations to improve their reliability and performance while reducing operating costs.

Water and Steam Infrastructure

We own, control and operate water management and steam-generation infrastructure, including steam generators, steam plants, steam distribution systems, steam injection lines and headers, water softeners and water processing systems. We soften and self-supply water to generate steam, reducing our operating costs. This infrastructure is integral to our operations in the San Joaquin basin and supports our high-margin oil fields such as Kern Front.

Gathering Systems

We own an extensive network of over 8,000 miles of oil and natural gas gathering lines. These gathering lines 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. These lines connect our producing wells and facilities to gathering networks, natural gas collection and compression systems, and water and steam processing, injection and distribution systems. Our oil gathering systems connect to multiple third-party transportation pipelines, which increases our flexibility to ship to various parties. In addition, virtually all of our natural gas facilities connect with major third-party natural gas pipeline systems. As a result of these connections, we typically have the ability to access multiple delivery points to improve the prices we obtain for our oil and natural gas production.

Oil and NGL Storage

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.

Regulation of the Oil and Natural Gas Industry

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

Federal, state and local laws and regulations govern most aspects of exploration and production in California, including:

- oil and natural gas production, including siting and spacing of wells and facilities on federal, state and private lands with associated conditions or mitigation measures;
- methods of constructing, drilling, completing, stimulating, operating, inspecting, maintaining and abandoning wells;
- the design, construction, operation, inspection, maintenance and decommissioning of facilities, such as natural gas processing plants, power plants, compressors and liquid and natural gas pipelines or gathering lines;
- improved or enhanced recovery techniques such as fluid injection for pressure management;
- sourcing and disposal of water used in the drilling, completion, stimulation, maintenance and improved or enhanced recovery processes;
- imposition of taxes and fees with respect to our properties and operations;
- the conservation of oil and natural gas, including provisions for the unitization or pooling of oil and natural gas properties;
- posting of bonds or other financial assurance to drill, operate and abandon or decommission wells and facilities; and
- health, safety and environmental matters and the transportation, marketing and sale of our products as described below.

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.

CalGEM is California’s primary regulator of the oil and natural gas industry on private and state lands, with additional oversight from the State Lands Commission’s administration of state surface and mineral interests. The Bureau of Land Management (BLM) of the U.S. Department of the Interior exercises similar jurisdiction on federal lands in California, on which CalGEM also asserts jurisdiction over certain activities. Government actions, including the issuance of certain permits or approvals, by state and local agencies or by federal agencies may be subject to environmental reviews, respectively, under the California Environmental Quality Act (CEQA) or the National Environmental Policy Act (NEPA), which may result in delays, imposition of mitigation measures or litigation. CalGEM currently requires an operator to identify the manner in which 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 gas ordinance, which was supported by an Environmental Impact Report (EIR) certified by the Kern County Board of Supervisors in 2015. A group of plaintiffs challenged the EIR and on February 25, 2020, a California Court of Appeal issued a ruling that invalidates a portion of the EIR until the County makes certain revisions to the EIR and recertifies it. On February 12, 2021, the Kern County Planning Commission voted to recommend approval of the revisions in a supplementary EIR in order to reestablish the county’s oil and gas permitting system, though it must be approved by the county Board of Supervisors before becoming effective. This certification is expected to be completed in the first half of 2021; however, the supplemental EIR and certification may also be subject to litigation. After the supplementary EIR is certified, it is expected that CalGEM will rely on Kern County to serve as lead agent for CEQA purposes, reducing unnecessary delays at the state level.

The California Legislature has 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. 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 November 2019, the State Department of Conservation issued a press release announcing three actions by CalGEM: (1) a moratorium on approval of new high–pressure cyclic steam wells pending a study of the practice to address surface expressions experienced by certain operators; (2) review and updating of regulations regarding public health and safety near oil and natural gas operations pursuant to additional duties assigned to CalGEM by the Legislature in 2019; and (3) a performance audit of CalGEM's permitting processes for well stimulation treatment (WST) permits and project approval letters for underground injection (PALs) by the State Department of Finance and an independent review and approval of the technical content of pending WST and PAL applications by Lawrence Livermore National Laboratory. In September 2020, the Governor of California issued an executive order which, among other actions, requires CalGEM to complete its public health and safety review and propose additional regulations, which are expected to be released for public comment in the spring of 2021 and to include expanded land use setbacks or buffer zones, and noted the Governor's intent to seek legislation to end the issuance of new hydraulic fracturing permits by 2024. For more information, see *Part I, Item 1A – Risk Factors.* While the full impacts of this executive order cannot be predicted, additional state regulation of exploration and production activities could result in increased operating costs or delays in or the inability to obtain permits, or otherwise adversely affect production from the underlying properties.

The U.S. Environmental Protection Agency (EPA) and the BLM also regulate certain oil and gas activities. In January 2021, the Biden Administration issued orders temporarily suspending the issuance of new authorizations, and suspending the issuance of new leases (to the extent permitted by law) pending completion of a review of current practices, for oil and gas development on federal lands (the orders do not restrict such operations on tribal lands that the federal government merely holds in trust). Although the orders do not apply to existing operations under valid leases, we cannot guarantee that further action will not be taken to curtail oil and gas development on federal lands.

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 2020 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 Pipeline and Hazardous Materials Safety Administration issued new regulations in October 2019 expanding integrity management, leak detection and reporting requirements for liquid pipelines and natural gas transmission pipelines, with various implementation periods beginning in July 2020 and specific requirements dependent upon the characteristics of the line and its location.

In 2020, CalGEM commenced a series of public health and safety workshops to be followed by an associated rulemaking process that will consider various measures, including expanded land use setbacks or buffer zones. In February 2021, Senate Bill 467 (SB 467) was introduced. If passed, the bill would ban permits for hydraulic fracturing, acid well stimulation treatments, cyclic steaming, water flooding and steam flooding beginning in 2022 and would ban these activities entirely beginning in 2027. The bill would also allow local governments to prohibit such practices prior to 2027. After the bill was introduced one of the authors announced that it would also be amended to also add a 2,500 feet setback for new wells from sensitive receptors. We cannot predict the outcome of this most recent legislative effort. Previous high profile efforts to impose setbacks for new wells from sensitive receptors have failed; however, any restrictions on the use of well stimulation treatments or expanded setbacks could adversely impact our operations.

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. The most onerous of these local measures were adopted in 2016 by Monterey County, where we owned mineral rights but have no production and in 2020 by Ventura County, where we have both mineral rights and production. As written, the Monterey County measure sought to prohibit the drilling of new oil and natural gas wells, hydraulic fracturing and other well-stimulation techniques and to phase out the injection of produced water. This measure was challenged in state court and the Monterey County Superior Court issued a decision in 2017, finding that the bans on drilling new wells and water injection are preempted by and invalid under existing state and federal regulations and, if implemented, would constitute a taking of our property and that of other mineral rights owners without compensation. The court did not rule on the ban on hydraulic fracturing because the court found that the issue was not ripe since hydraulic fracturing is not currently being conducted in Monterey County, noting that the ban could be challenged in the event a project involving hydraulic fracturing is proposed. Although the County is complying with and declined to appeal the Court’s decision and settled the litigation, sponsors of the ballot measure have appealed.

In September 2020, the Ventura County Board of Supervisors (Ventura Board) adopted an amended General Plan and approved an associated EIR that impose significant restrictions on new discretionary development projects in Ventura County. With respect to new discretionary oil and gas development, the amended General Plan: requires setbacks of 1,500 feet and 2,500 feet from residences and schools, respectively; prohibits trucking of oil and produced water; restricts flaring; requires electrification of equipment; and requires additional reviews for projects involving WST or steam injection. Collectively, these restrictions would prevent or substantially reduce new development of at least five fields that we operate. In November 2020, the Ventura Board adopted ordinances to unilaterally revoke or revise longstanding conditional use permits, including permits held by us, thereby applying the amended General Plan to fields with existing permits, and to amend coastal and non-coastal specific plans to impose a 15-year time limit and other restrictions on new permits. Multiple lawsuits have been filed challenging the amended General Plan and EIR, including by us, on numerous statutory and constitutional grounds, and litigation is expected on the other ordinances as well.

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, and 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. As previously noted, the State Department of Finance is conducting a performance audit of CalGEM's permitting process for injection projects, with an independent review of the technical content of pending injection PALs by Lawrence Livermore National Laboratory.

Separately, the state began a review in 2015 of permitted surface discharge of produced water and the use of reclaimed water for agricultural irrigation, which led to additional permitting and monitoring requirements in 2017 for surface discharge. To date, the foregoing regulatory actions have not affected our oil and natural gas operations in a material way. These reviews are ongoing, and government authorities may ultimately restrict injection of produced water or other fluids in additional formations or certain wells, restrict the surface discharge or use of produced water or take other administrative actions. The foregoing reviews could also give rise to litigation with government authorities and third parties.

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 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 announced that climate change will be a focus of his administration, and he has issued several executive orders on the subject, which, among other things, recommit the United States to the Paris Agreement, call for the reinstatement or issuance of methane emissions standards for new, modified and existing oil and gas facilities and call 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 Governor 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 2020, the Governor of California issued an executive order directing several agencies to take further actions with respect to reducing emissions of GHGs. For more information, see *Part I, Item 1A – Risk Factors.*

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, several lawsuits have been filed challenging these amendments, and the amendments may be subject to reversal under a new presidential administration. 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.

Risks Related to Our Business

Prices for our products can fluctuate widely and an extended period of low prices could 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. In particular, as described in the risk factor below, the COVID-19 pandemic and related economic repercussions have had a significant impact on commodity prices. During the second quarter of 2020, the price of Brent crude oil reached a historic low of just under $20 per barrel. The current futures forward curve for Brent crude indicates that prices are expected to continue at about current levels for an extended time. The estimated average benchmark Brent oil price used to determine our December 31, 2020 reserves was $41.77 per barrel as compared to the average benchmark Brent oil price used to determine our 2019 year-end reserves of $63.15 per barrel, both based on SEC pricing.

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;
- 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, including as a result of impairments of existing reserves;
- limiting our ability to grow or maintain future production including a delay in the reversion dates of certain of our JVs;
- causing a reduction in our borrowing base under our Revolving Credit Facility, which could affect our liquidity;
- reducing our 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.

The COVID-19 pandemic caused crude oil prices to decline significantly in 2020, which has materially and adversely affected our business, results of operations and financial condition.

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. As a result, there has been an unprecedented reduction in demand for crude oil. The severity, magnitude and duration of current or future COVID-19 outbreaks, 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. Lower future commodity prices caused by the COVID-19 pandemic 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. Starting in March 2020, we reduced our operating expenses and planned capital expenditures to those necessary to maintain mechanical integrity of our facilities to operate them in a safe and environmentally responsible manner. In addition, we shut-in wells which reduced our 2020 net production by 3 MBoe/d. These operational decisions negatively impacted our production and may materially and adversely affect the quantity of estimated proved reserves that may be attributed to our properties. Our operations also may be adversely affected if significant portions of our workforce are unable to work effectively, including because of illness, quarantines, government actions or other restrictions in connection with the pandemic. In addition, we are exposed to changes in commodity prices which have been and will likely remain volatile.

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.

Recent and future actions by the state of California could result in restrictions to our operations and result in decreased demand for oil and gas within the state.

In September 2020, Governor Gavin Newsom of California issued an executive order (Order) that seeks to reduce both the demand for and supply of petroleum fuels in the state. The Order establishes several goals and directs several state agencies to take certain actions with respect to reducing emissions of GHGs, including, but not limited to: phasing out the sale of new emissions-producing passenger vehicles, drayage trucks and off-road vehicles by 2035 and, to the extent feasible, medium and heavy duty trucks by 2045; developing strategies for the closure and repurposing of oil and gas facilities in California; and proposing legislation to end the issuance of new hydraulic fracturing permits in the state by 2024. The Order also directs the California Department of Conservation, Geologic Energy Management Division (CalGEM) to strictly enforce bonding requirements for oil and gas operations and to complete its ongoing public health and safety review of oil production and propose additional regulations, which are expected to include expanded land use setbacks or buffer zones. In October 2020, the Governor issued an executive order that establishes a state goal to conserve at least 30% of California’s land and coastal waters by 2030 and directs state agencies to implement other measures to mitigate climate change and strengthen biodiversity. In February 2021, SB 467 was introduced in the state senate. If passed, the bill would ban new permits for hydraulic fracturing, acid well stimulation treatments, cyclic steaming, water flooding and steam flooding – beginning in 2022 and would ban these activities beginning in 2027. The bill would also allow local governments to prohibit such practices prior to 2027. After the bill was introduced one of the authors announced that it would also be amended to also add a 2,500 feet setback for new wells from sensitive receptors. We cannot predict the outcome of this most recent legislative effort. Previous high profile efforts to pass mandatory setbacks have failed; however, any of the foregoing developments and other future actions taken by the state may materially and adversely affect our operations and properties and the demand for our products.

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. Federal, state and local agencies may assert overlapping authority to regulate these areas. For example, the jurisdiction, duties and enforcement authority of various state agencies have significantly increased with respect to oil and natural gas activities in recent years, and these state agencies as well as certain cities and counties have significantly revised their regulations, regulatory interpretations and data collection and reporting requirements and plan to issue additional regulations governing various oil and natural gas activities in the future. On November 9, 2020, the EPA approved reclassification of the South Coast Air Quality Management District non-attainment area for the 2012 fine particulate matter National Ambient Air Quality Standard to “serious nonattainment,” which requires California to submit an attainment plan to achieve attainment as expeditiously as practicable. Any restrictions imposed by California pursuant to any future attainment plan to comply with this designation of serious nonattainment may result in increased compliance costs and adversely affect our business and results of operations. In addition, certain of these federal, state and local 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.

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. 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 customers, including refineries and utilities, and the businesses that transport our products to customers, are also highly regulated. For example, various government authorities have sought to restrict the use of oil, natural gas or certain petroleum–based products such as fuels and plastics. Federal and state pipeline safety agencies have adopted or proposed regulations to expand their jurisdiction to include more gas and liquid gathering lines and pipelines and to impose additional mechanical integrity, leak detection and reporting requirements. The state has adopted additional regulations on the storage of natural gas that could affect the demand for or availability of such storage, increase seasonal volatility, or otherwise affect the prices we receive from customers. The California Public Utilities Commission (CPUC) has 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. Certain municipalities have enacted restrictions on the installation of natural gas appliances and infrastructure in new residential or commercial construction, which could affect the retail natural gas market for our utility customers and the demand and prices we receive for the natural gas we produce.

Costs of compliance may increase and operational delays or restrictions may occur as existing laws and regulations are revised or reinterpreted, or as new laws and regulations become applicable to our operations, each of which has occurred in the past.

Government authorities and other organizations continue to study health, safety and environmental aspects of oil and natural gas operations, including those related to air, soil and water quality, ground movement or seismicity and natural resources. For example, the California legislature expanded CalGEM duties in 2019 to include public health and safety and CalGEM is expected to complete a review of potential public health and safety concerns resulting from the impacts of oil and gas extraction activities by the first half of 2021 and to propose a rulemaking to address the findings of the agency's review. Government authorities have also adopted or proposed new or more stringent requirements for permitting, inspection and maintenance of wells, pipelines and other facilities, and public disclosure or environmental review of, or restrictions on, oil and natural gas operations, including proposed setback distances or buffer zones from other land uses, as well as proposals to declare oil and gas production a non-conforming use in certain jurisdictions in an effort to prevent future development or phase out existing production over time. Such requirements or associated litigation could result in potentially significant added costs to comply, delay or curtail our exploration, development, fluid injection and disposal or production activities, preclude us from drilling, completing or stimulating wells, or otherwise restrict our ability to access and develop mineral rights, any of which could have an adverse effect on our expected production, other operations and financial condition.

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.

Recent actions by the Biden administration could result in restrictions to our operations

In January 2021, the U.S. Department of the Interior announced that it was restricting its employees for a period of 60 days, other than senior identified leadership, from approving certain activities including entering into new leases or approving drilling permits on public lands and waters. Approximately 9% of our net production is on federal lands and the Biden administration may extend such restrictions or add others that make it more difficult or costly to operate on these lands.

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 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 17% of our total net undeveloped acreage at December 31, 2020.

Our business can involve substantial capital investments, which may include acquisitions or JVs. We may be unable to fund these investments 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. Following our emergence from Chapter 11 bankruptcy, our capital investments will mainly be funded through a combination of cash flow from operations and borrowings under our Revolving Credit Facility. We seek to manage our internally funded capital investments to align with projected 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
- the availability of external sources of financing.

Access to future capital may be limited by our lenders, our JV partners, 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 JVs.

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.

From time to time we may engage in exploratory drilling, including 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 our exploration drilling locations is higher than for other locations because we have less geologic and production data and drilling history, in particular for those exploration drilling locations 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.

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 include local price fluctuations, changes in state or regional laws and regulations affecting our operations 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 and earthquakes. 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.

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 commodity price risk-management activities may prevent us from fully benefiting from price increases and may expose us to other risks.

Our commodity price risk-management activities may prevent us from realizing the full benefits of price increases above any levels set in certain derivative instruments we may use to manage price risk. In addition, our commodity price risk-management activities may expose us to the risk of financial loss in certain circumstances, including instances in which the counterparties to our hedging or other price-risk management contracts fail to perform under those arrangements.

Under the Revolving Credit Facility, we are required to maintain acceptable commodity hedges hedging no less than (i) 75% of our reasonably anticipated oil production from our proved reserves for the first 24 months after the closing of the Revolving Credit Facility, which occurred upon emergence from bankruptcy and (ii) 50% of our reasonably anticipated oil production from our proved reserves for a period from the 25th month through the 36th month after the same date. The Revolving Credit Facility specifies the forms of hedges and prices (which can be prevailing prices) that must be used.

For the remaining duration of the Revolving Credit Facility, we must maintain acceptable commodity hedges for no less than 50% of the reasonably anticipated total forecasted production of crude oil from our oil and gas properties for at least 24 months following the date of delivery of each reserve report. We may not hedge more than 80% of reasonably anticipated total forecasted production of crude oil, natural gas and NGLs from our oil and gas properties for a 48-month period.

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 may affect both the size of positions that we may enter and the ability or willingness of counterparties to trade opposite us, potentially increasing costs for transactions. Moreover, the effects of these regulations could reduce our hedging opportunities which could adversely affect our revenues and cash flow during periods of low commodity prices.

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 are required to comply with the new SA-CCR rules beginning on January 1, 2022. The new rules could significantly increase the capital requirements for certain participants in the OTC derivatives market in which we participate. 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. These regulations could result in a reduction in our hedging opportunities or substantially increase our cost of hedging, which could adversely affect our business, financial condition and results of operations.

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.

Our actual financial results after emergence from bankruptcy may differ significantly from the projections included in our Plan. In addition, our actual financial results may not be comparable to our historical financial information as a result of the implementation of our Plan and our adoption of fresh start accounting.

In connection with the disclosure statement we filed with the Bankruptcy Court, and the hearing to consider confirmation of our Plan, we prepared projected financial information to demonstrate to the Bankruptcy Court the feasibility of our Plan and our ability to continue operations upon our emergence from bankruptcy. Those projections were prepared solely for the purpose of the bankruptcy proceedings and have not been, and will not be, updated on an ongoing basis and should not be relied upon by investors. At the time they were prepared, the projections reflected numerous assumptions concerning our anticipated future performance with respect to prevailing and anticipated market and economic conditions that were and remain beyond our control and that may not materialize. Projections are inherently subject to substantial and numerous uncertainties and to a wide variety of significant business, economic and competitive risks and the assumptions underlying the projections and/or valuation estimates may prove to be wrong in material respects. Actual results will likely vary significantly from those contemplated by the projections. As a result, investors should not rely on these projections.

In addition, upon our emergence from bankruptcy, we adopted fresh start accounting, as a result of which our assets and liabilities were recorded at fair value, which are materially different than the amounts reflected in our historical financial statements. Accordingly, our future financial statements may not be comparable to our historical financial statements.

Risks Related to our Indebtedness

Our existing and future indebtedness may adversely affect our cash flows and ability to operate our business, remain in compliance and repay our debt.

As of December 31, 2020, we had $599 million of total long-term debt, and additional borrowing capacity of $307 million under the Revolving Credit Facility (after taking into account $134 million of outstanding letters of credit). In addition, as of December 31, 2020, on a pro forma basis giving effect to the January 2021 issuance of our Senior Notes as described in *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity, High Yield Debt Offering*, we would have had approximately $397 million available for borrowing under the Revolving Credit Facility (after taking into account $134 million of outstanding letters of credit). The indenture that governs the Senior Notes permits us to incur significant additional debt, some of which may be secured. Our level of indebtedness could affect our operations 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;
- 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;
- make us vulnerable to increases in interest rates as our indebtedness under the Revolving Credit Facility varies with prevailing interest rates;
- place us at a competitive disadvantage relative to our competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and

- make it more difficult for us to satisfy our obligations under the Senior Notes or other debt and increase the risk that we may default on our debt obligations.

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.

Our lenders could limit our borrowing capabilities and restrict our ability to use or access 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, including various leverage ratios, hedging requirements and reporting obligations.

The borrowing base under our Revolving Credit Facility is redetermined semi-annually on April 1 and October 1 of each year. Our lenders determine our borrowing base by reference to the value of our reserves and other factors that the administrative agent may deem appropriate in good faith in accordance with its usual and customary oil and gas lending criteria as they exist at the particular time. The lenders under our Revolving Credit Facility may also factor other liabilities, including our other indebtedness, into the determination of our borrowing base. Currently, our borrowing base is set at $1.2 billion. Availability under our Revolving Credit Facility is the least of (i) the then-effective borrowing base, (ii) the then-effective aggregate commitments and (iii) the aggregate elected commitment amount, which is currently set at $540 million. The aggregate revolving commitment is subject to an automatic reduction if additional commitments from new lenders are not obtained. As a result, we expect the aggregate commitment of our lenders will be reduced to $492 million in April 2021.

Any reduction in our borrowing base could materially and adversely affect our liquidity and may hinder our ability to execute on our business strategy.

Restrictive covenants in our Revolving Credit Facility may limit our financial and operating flexibility.

As of December 31, 2020, total outstanding borrowings under the Revolving Credit Facility were $99 million and we had $307 million of available borrowing capacity after taking into account $134 million of outstanding letters of credit. Our Revolving Credit Agreement permits us to incur significant additional indebtedness as well as certain other obligations. In addition, we may seek amendments or waivers from our existing lenders to the extent we need to incur indebtedness above amounts currently permitted by our financing agreements.

Our Revolving Credit facility contains certain restrictions, which may have adverse effects on our business, financial condition, cash flows or results of operations, limiting our ability, among other things, to:

- incur additional indebtedness;
- incur additional liens;
- pay dividends or make other distributions;
- make investments, loans or advances;
- sell or discount receivables;

- enter into mergers;
- sell properties;
- enter into or terminate hedge agreements;
- enter into transactions with affiliates;
- maintain gas imbalances;
- enter into take-or-pay contracts or make other prepayments;
- enter into sale and leaseback agreements;
- prepay or modify the terms of junior debt;
- enter into negative pledge agreements;
- enter into production sharing contracts;
- amend our organizational documents; and
- 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. If a default occurs, 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 thereunder will also have the right to proceed against the collateral pledged to them to secure the indebtedness.

Variable rate indebtedness under our Revolving Credit Facility subjects us to interest rate risk, which could cause our debt service obligations to increase significantly. In addition, uncertainty relating to the LIBOR calculation process and potential phasing out of LIBOR after 2021 may adversely affect the market value of our current or future indebtedness.

Borrowings under our Revolving Credit Facility are at variable rates of interest and expose us to interest rate risk. As such, our results of operations are 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 a certain portion of our debt. 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.

In addition, a transition away from the London Interbank Offered Rate (LIBOR) as a benchmark for establishing the applicable interest rate may affect the cost of servicing our debt under the Revolving Credit Facility. The Financial Conduct Authority of the United Kingdom has announced that it plans to phase out LIBOR by the end of calendar year 2021. Although the Revolving Credit Agreement provides for alternative base rates, such alternative base rates may or may not be related to LIBOR, and the consequences of the phase out of LIBOR cannot be entirely predicted at this time. For example, if any alternative base rate or means of calculating interest with respect to our outstanding variable rate indebtedness leads to an increase in the interest rates charged, it could result in an increase in the cost of such indebtedness, impact our ability to refinance some or all of our existing indebtedness or otherwise have a material adverse impact on our business, financial condition and results of operations. Further, the discontinuation, reform or replacement of LIBOR or any other benchmark rates may have an unpredictable impact on contractual mechanics in the credit markets or cause disruption to the broader financial markets.

Risks Related to Our Common Stock

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 sales 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 February 28, 2021, we had 83,319,660 outstanding shares of common stock and 4,384,182 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.

Based on the most recent available public information, four of our shareholders collectively own approximately 72% 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.

General Risk Factors

Concerns about climate change and other air quality issues may 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 recent years, the regulation of methane emissions from oil and gas facilities has been subject to uncertainty. In September 2020, the Trump Administration revised prior regulations to rescind certain methane standards and remove the transmission and storage segments from the source category for certain regulations. However, on January 20, 2021, President Biden signed an executive order calling for the suspension, revision, or rescission of the September 2020 rule and the reinstatement or issuance of methane emissions standards for new, modified, and existing oil and gas facilities.

Internationally, the United Nations-sponsored Paris Agreement requires member states to individually determine and submit non-binding emissions reduction targets every five years after 2020. President Biden has signed executive orders recommitting to the Paris Agreement, and calling on the federal government to develop the United States' emissions reduction target. In addition, the current and former Governor 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.

Concern over climate change and GHG and other emissions has also resulted in increasing political risks in California and the United States, including climate change related pledges made by various candidates for and holders of public office. On January 27, 2021 President Biden issued an executive order calling for substantial action on climate change, including, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risk across governmental agencies and economic sectors. The January 27 order also suspends the issuance of new leases for oil and gas development on federal lands, to the extent permitted by law, pending completion of a review of current practices. Other actions that could be pursued by President Biden include more restrictive requirements for the establishment of pipeline infrastructure or other GHG emissions limitations for oil and gas facilities, which could negatively impact our operations and the value or use of our properties. Additionally, various claimants, including certain municipalities, have filed litigation alleging that energy producers are liable for damages attributed to climate change. Suits have also been brought against such companies under shareholder and consumer protection laws, alleging that the companies have been aware of the adverse effects of climate change but failed to adequately disclose those impacts.

In addition, other current and proposed international agreements and federal, state and local laws, regulations and policies seek to restrict or reduce the use of petroleum products in transportation fuels, electricity generation, plastics and other applications, prohibit future sale or use of vehicles, appliances or equipment that require petroleum fuels, impose additional taxes and costs on producers and consumers of petroleum products and require or subsidize the use of renewable energy. California has set an ambitious goal by executive order to be "carbon-neutral" by 2045 and initiated and funded studies to identify strategies to implement this goal. The California legislature, state agencies and various municipalities have adopted or proposed laws, regulations and policies that seek to significantly reduce emissions from vehicles, increase the use of "zero emission" vehicles, reduce the use of plastics, increase renewable energy mandates for utilities and in residential and commercial construction, and replace natural gas appliances and infrastructure in residential and commercial buildings with electric appliances.

Government authorities can impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations, and various state and local agencies are conducting increased regional, community and field air monitoring specifically with respect to oil and natural gas operations. In addition, California air quality laws and regulations, particularly in Southern and Central California where most of our operations are located, are in most instances more stringent than analogous federal laws and regulations. For example, the San Joaquin Valley will be required to adopt more rigorous attainment plans under the Clean Air Act to comply with federal ozone and particulate matter standards, and these efforts could affect our activities in the region and our ability and cost to obtain permits for new or modified 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 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 gas companies. Additionally, proponents of the Paris Agreement, including various state agencies and municipalities in California, and other governmental and non-governmental organizations concerned about climate change have sought to pressure public and private investment funds not to invest in oil and gas companies and institutional lenders to restrict oil and gas companies' access to capital. Recently, President Biden issued an executive order calling for the development of a "climate finance plan", and, separately, the Federal Reserve announced that it has applied to join the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. Limitation of investments in and financings for oil and gas companies like us could result in the restriction, delay or cancellation of drilling programs or development or production activities.

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.

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. Legislation has been previously 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 gas exploration and production companies. Such changes include, but are not 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; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. 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. Although such proposals targeting our industry have not become law, campaigns by various interest groups could lead to additional future taxes.

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 over 80% of our estimated proved reserve volumes as of December 31, 2020 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, including:

- historical production from the area compared with production from similar areas;
- the quality, quantity and interpretation of available relevant data;
- commodity prices;
- production and operating costs;
- ad valorem, excise and income taxes;
- development costs;
- the effects of government regulations; and
- future workover and facilities costs.

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.

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.

Part of our business strategy involves divesting non-core assets. 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 oil and natural gas exploration and production activities and our assets are subject to risks such as fires, explosions, releases, discharges, power outages, equipment or information technology failures and industrial accidents, as are the assets and properties of third parties who supply us with energy, equipment and services or who purchase, transport or use our products. 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. In addition, events such as earthquakes, floods, mudslides, wildfires, power outages, high winds, droughts, cybersecurity, vandalism or terrorist attacks and other events may cause operations to cease or be curtailed and could adversely affect our business, workforce and the communities in which we operate. Further, recent wildfires experienced in California have limited the availability and increased the cost of obtaining insurance against certain natural disasters. 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.

Information technology failures and cybersecurity attacks 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 in recent years and include attempts to gain unauthorized access to data, malicious software, ransomware and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential information or the corruption of data. In addition, our vendors, customers and other business partners may separately suffer disruptions or breaches from cybersecurity attacks that, in turn, could adversely impact our operations and compromise our information. 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. As the sophistication of cybersecurity attacks continues to evolve, we may be required to expend additional resources to further enhance our security.

Increasing attention to environmental, social and governance (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. 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.

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 10 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

On October 27, 2020, the Successor company's common stock was 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 approximately 175 stockholders of record at December 31, 2020.

Dividend Policy

We have not declared or paid dividends on either the Predecessor or the Successor company's respective common stock during 2019 or 2020. Our Revolving Credit Facility generally restricts the payment of dividends on our stock, subject to certain exceptions. Currently, we do not pay dividends, but may do so in future periods depending on our ability to do so under our Revolving Credit Facility.

Securities Authorized for Issuance Under Equity Compensation Plans

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

On October 27, 2020 in connection with our emergence from bankruptcy, the Amended and Restated California Resources Corporation Long-Term Incentive Plan and all outstanding awards thereunder were cancelled.

On January 18, 2021, our Board of Directors approved the California Resources Corporation 2021 Long Term Incentive Plan (2021 Incentive Plan). The shares issuable under the new long-term incentive plan had been previously authorized by the United States Bankruptcy Court for the Southern District of Texas in connection with our emergence from Chapter 11 of the Bankruptcy Code and the terms of the new long-term incentive plan were approved by our Board of Directors. As a result, the 2021 Incentive Plan became effective on January 18, 2021. The 2021 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 2021 Incentive Plan provides for the reservation of 9,257,740 shares of common stock for future issuances, subject to adjustment as provided in the 2021 Incentive Plan. Shares of stock subject to an award under the 2021 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 2021 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 2021 Incentive Plan.

ITEM 6 SELECTED FINANCIAL DATA

Not applicable.

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.

We emerged from Chapter 11 bankruptcy proceedings on October 27, 2020 as further described below. We adopted and applied the relevant guidance with respect to the accounting and financial reporting for entities that have emerged from bankruptcy proceedings. Under fresh start accounting, the reorganized entity is considered a new reporting entity. We elected to apply fresh start accounting effective October 31, 2020, an accounting convenience date, and the $2.5 billion reorganization value of the emerging entity was assigned to individual assets and liabilities based on their estimated relative fair values. As such, fresh start accounting was reflected on our consolidated balance sheet as of October 31, 2020. 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.

Certain operating results and key operating performance measures, for example production, average realized prices, revenues, operating expense, taxes other than on income and general and administrative expenses, were not significantly impacted by the reorganization. Accordingly, we believe that discussing the combined results of operations and cash flows of the Predecessor and Successor companies is useful when analyzing financial results and performance measures. For items that are not comparable, for example depreciation, depletion and amortization, interest expense, impairment and net income (loss), we have included additional analysis.

Emergence from Bankruptcy Proceedings and Subsequent Refinancing

On July 15, 2020, we filed voluntary petitions for relief under Chapter 11 of Title 11 of the Bankruptcy Code in the Bankruptcy Court. The Chapter 11 Cases were jointly administered under the caption *In re California Resources Corporation, et al.*, Case No. 20-33568 (DRJ). We filed with the Bankruptcy Court, on July 24, 2020, the *Debtors' Joint Plan of Reorganization under Chapter 11 of the Bankruptcy Code* and, on October 8, 2020, the *Amended Debtors' Joint Plan of Reorganization Under Chapter 11 of the Bankruptcy Code*. On October 13, 2020, the Bankruptcy Court confirmed the Plan, which was conditioned on certain items such as obtaining exit financing. The conditions to effectiveness of the Plan were satisfied and we emerged from Chapter 11 on October 27, 2020 (Effective Date).

We emerged from bankruptcy on the Effective Date with a new board of directors, new equity owners and a significantly improved financial position. Under the plan of reorganization approved by the Bankruptcy Court (the Plan), all of our outstanding pre-emergence indebtedness under our credit facilities and senior notes was cancelled. At emergence, we entered into a new revolving credit facility with a $1.2 billion borrowing base and $540 million of lender commitments (Revolving Credit Facility). Our post-emergence capital structure also included a $200 million second lien term loan (Second Lien Term Loan) and $300 million of secured notes due 2027 issued by our wholly-owned subsidiary in connection with our acquisition of our partner's interest in our Elk Hills power joint venture (EHP Notes).

On January 20, 2021, we completed an offering of $600 million aggregate principal amount of 7.125% senior notes due 2026 (Senior Notes). We used the net proceeds to repay in full our Second Lien Term Loan and EHP Notes, with the remainder of the net proceeds used to repay a portion of the outstanding borrowings under our Revolving Credit Facility.

For information on the transactions which occurred pursuant to the Plan upon our emergence from Chapter 11 and fresh start accounting, see *Part II, Item 8 – Financial Statements, Note 2 Chapter 11 Proceedings* and *Part II, Item 8 – Financial Statements, Note 3 Fresh Start Accounting.*

Response to COVID-19 Pandemic and Industry Downturn

We have taken several steps and continue to actively work to mitigate the effects of the COVID-19 pandemic and the industry downturn on our operations, financial condition and liquidity.

In response to the rapid fall in commodity prices in March 2020, we ceased all field development and growth projects and shut in certain wells. We also reduced our 2020 capital budget to a level that preserves the mechanical integrity of our facilities and allows us to operate them in a safe and environmentally responsible manner. As a result, our production declined during 2020. Our 2021 capital investment program targets development of shallow oil projects in core fields and with this program, we expect total production (on a BOE basis) will decline moderately throughout 2021; however, we believe oil production will likely remain mostly flat from entry to exit. We also monetized all of our crude oil hedges in March 2020, except for certain hedges held by our joint venture with Benefit Street Partners (BSP JV), for approximately $63 million to preserve our liquidity. We began shutting in high cost, negative margin wells in March 2020 to reduce operating costs and enhance cash flow which curtailed average net production volumes by approximately 3 MBoe/d in 2020. We began returning wells to production in December 2020. As part of our operational efficiency measures, we evaluated our diverse portfolio and our various production mechanisms with a focus on wells with higher operating costs. Our teams utilized our extensive automation controls, monitored weekly well margins, and made temporary adjustments to our producing wells to ensure our operations aligned with the price environment. As a result of these actions, as well as further cost rationalization and streamlining efforts coupled with lower activity levels, our average operating expense run rate in the second half of 2020 was approximately $50 million per month compared to the first quarter of 2020 average of $65 million per month.

We have also implemented various measures to protect the health of our workforce and to support the prevention of COVID-19 at our plants, rigs, fields and administrative offices. These initiatives were implemented in accordance with the orders, regulations and guidance of federal, state and local authorities to mitigate the risks of the disease and included restricting non-essential travel and temporarily closing our administrative offices during periods of higher incidence of community spread from mid-March until mid-June 2020 and resuming again in mid-November 2020 by implementing remote work for our management team and substantially all of our office personnel, with limited return to the office in accordance with applicable protocols and restrictions on occupancy for those employees for whom remote work was not feasible. In addition, in April 2020, we implemented reduced work hours for nearly all of our office employees and reduced salaries for our management team, in each case on a temporary basis that ended in May 2020. In August 2020, we implemented organizational and operational efficiencies that resulted in a reduction of our headcount to approximately 1,100 employees. These actions were made in an effort to preserve liquidity after the deterioration of commodity prices following the outbreak of COVID-19. Our operational employees and contractors, and certain support personnel, have been classified as an essential critical infrastructure workforce by government authorities. Accordingly, these essential personnel have been authorized to continue to work in their plant, rig, field and office locations under our COVID-19 Health and Safety Plan, which includes, among other things, protocols for employee training, health self-assessment screening by workers and visitors entering our locations, reporting of illness, notification of workers and contact tracing associated with positive COVID-19 cases, self-quarantine or isolation, hygiene, wearing facial coverings, applying social distancing to minimize close contact between workers, cleaning or disinfecting workspaces and protection of emergency response personnel. We have not experienced any operational slowdowns due to COVID-19 among our workforce.

Production and Prices

Prices for oil and gas products in 2020 have been strongly influenced by the COVID-19 pandemic and by the actions of foreign producers. The COVID-19 pandemic caused an unprecedented demand collapse due to global shelter-in-place orders, travel restrictions and general economic uncertainty, which negatively impacted crude oil prices. In response, members of the OPEC and Russia agreed to carry out record oil production cuts in April 2020 to be followed by gradual incremental increases in multiple steps. In addition, U.S. oil and gas companies reduced their oil production by approximately 3 MMBbl/d in 2020 from peak production levels addressing the oversupplied market situation at the time of crisis. Due to these developing market dynamics, which include a successful OPEC+ agreement, a disciplined return of production in the U.S. and a broader, gradual return of demand, oil prices rebounded above $50 per barrel by the end of 2020. Brent oil price traded around $60 per barrel in February 2021.

Reduced demand initially caused shortages in available storage facilities globally and required many oil and gas producers to shut-in wells or curtail production. In April 2020, oil prices declined precipitously, temporarily reaching negative values for spot West Texas Intermediate (WTI) crude. From May 2020 through August 2020, oil prices began to recover as inventory levels stabilized and an easing of shelter-in-place restrictions created partial demand recovery. Prices declined again slightly in September 2020 as demand for oil dropped due to an increase in COVID-19 cases around the world. Oil demand and underlying commodity prices remain fragile as potential resurgence in new COVID-19 cases could force government authorities to re-impose mobility restrictions further impacting oil demand. The current futures forward curve for Brent crude indicates that prices may maintain current levels in the near term.

We continue to closely monitor the impact of COVID-19, which negatively impacted our business and results of operations beginning in the first quarter of 2020. The extent to which our 2021 operating results are impacted by the pandemic will depend largely on future developments, which are highly uncertain and cannot be accurately predicted, including the delivery of vaccinations, a resurgence of the pandemic or mutation of the virus and actions taken to contain it or actions taken by government authorities or other producers in response to commodity price movements, among other things. See *Part I, Item 1A – Risk Factors*, for further discussion regarding the impact of the pandemic and declines in commodity prices.

The following table sets forth our average net production volumes of oil, NGLs and natural gas per day for the years ended December 31, 2020, 2019 and 2018:

	Successor	Predecessor	Combined	Predecessor	
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	2020	2019	2018
Oil (MBbl/d)					
San Joaquin Basin	38	42	42	52	53
Los Angeles Basin	23	25	24	24	25
Ventura Basin	2	3	3	4	4
Total	63	70	69	80	82
NGLs (MBbl/d)					
San Joaquin Basin	12	13	13	15	15
Ventura Basin	—	—	—	—	1
Total	12	13	13	15	16
Natural gas (MMcf/d)					
San Joaquin Basin	138	147	145	162	165
Los Angeles Basin	1	2	2	2	1
Ventura Basin	3	4	4	5	7
Sacramento Basin	23	21	21	28	29
Total	165	174	172	197	202
Total Production (MBoe/d)[(a)(b)]	103	112	111	128	132

Note: MBbl/d refers to thousands of barrels per day; MMcf/d refers to millions of cubic feet per day; MBoe/d refers to thousands of barrels of oil equivalent per day.

(a) We temporarily shut-in production of 3 MBoe/d in 2020, which negatively impacted our production compared to 2019. Additionally, our divestiture of a 50% working interest in certain zones within our Lost Hills field resulted in a decrease of approximately 2 MBoe/d beginning in the second quarter of 2019. Our PSC-type contract positively impacted our oil production in 2020 by approximately 3 MBoe/d compared to 2019. PSC-type contracts had no impact on our oil production in 2019 compared to 2018.

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

Our operating results and those of the oil and natural gas industry as a whole are heavily influenced by commodity prices. 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		Predecessor	
	November 1, 2020 - December 31, 2020		January 1, 2020 - October 31, 2020	
	Price	Realization	Price	Realization
Oil ($ per Bbl)				
Brent	$ 47.10		$ 42.43	
Realized price without hedge	$ 45.65	97%	$ 41.21	97%
Settled hedges	(0.28)		1.98	
Realized price with hedge	$ 45.37	96%	$ 43.19	102%
WTI	$ 44.21		$ 38.44	
Realized price without hedge	$ 45.65	103%	$ 41.21	107%
Realized price with hedge	$ 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)	$ 2.86		$ 1.95	
Realized price without hedge ($/Mcf)	$ 3.21	112%	$ 2.11	108%
Settled hedges	(0.07)		0.06	
Realized price with hedge ($/Mcf)	$ 3.14	110%	$ 2.17	111%

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

	Combined		Predecessor			
	January 1, 2020 - December 31, 2020		2019		2018	
	Price	Realization	Price	Realization	Price	Realization
Oil ($ per Bbl)						
Brent	$ 43.21		$ 64.18		$ 71.53	
Realized price without hedge	$ 41.89	97%	$ 64.83	101%	$ 70.11	98%
Settled hedges	1.64		3.82		(7.51)	
Realized price with hedge	$ 43.53	101%	$ 68.65	107%	$ 62.60	88%
WTI	$ 39.40		$ 57.03		$ 64.77	
Realized price without hedge	$ 41.89	106%	$ 64.83	114%	$ 70.11	108%
Realized price with hedge	$ 43.53	110%	$ 68.65	120%	$ 62.60	97%
NGLs ($ per Bbl)						
Realized price(a)	$ 27.63	64%	$ 31.71	49%	$ 43.67	61%
Realized price(b)	$ 27.63	70%	$ 31.71	56%	$ 43.67	67%
Natural gas						
NYMEX ($/MMBTU)	$ 2.10		$ 2.67		$ 2.97	
Realized price without hedge ($/Mcf)	$ 2.28	109%	$ 2.87	107%	$ 3.00	101%
Settled hedges	0.04		(0.01)		(0.02)	
Realized price with hedge ($/Mcf)	$ 2.32	110%	$ 2.86	107%	$ 2.98	100%

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

Joint Ventures

We have a number of joint ventures that have allowed us to accelerate the development of our assets, which provided us with operational and financial flexibility as well as near-term production benefits.

Development Joint Ventures

Alpine JV

In July 2019, we entered into a development joint venture with Alpine Energy Capital, LLC (Alpine) to fund the drilling of certain wells within the Elk Hills field (Alpine JV). Alpine committed to invest an initial $320 million in the Elk Hills field of which $226 million has been invested to date. Our consolidated financial statements reflect only our working interest share in the productive wells.

On March 27, 2020, Alpine elected to suspend its funding obligations pursuant to a contractual right that was triggered when the average NYMEX 12-month forward strip price for Brent crude oil fell below $45 per barrel over a 30-trading day period. The suspension may be lifted by mutual consent. Funding for the initial development phase had not re-started.

In connection with the Alpine JV, we issued a warrant to purchase up to 1.25 million shares of our Predecessor common stock at an exercise price of $40 per share. On the Effective Date, this warrant was cancelled, pursuant to the Plan.

Royale JV

In October 2018, we entered into a three-year development joint venture for a 30-well program with Royale Energy, Inc. (Royale) where Royale committed approximately $23 million for natural gas development in Sacramento Valley, of which $8 million has been funded to date. We committed to investing approximately $13 million, of which $4 million has been funded to date. In June 2020, we entered into an amendment with Royale which postponed the start dates of the second- and third-year drilling programs by one year. Our consolidated results reflect our 40% working interest share of production from these wells.

MIRA JV

In April 2017, we entered into a development joint venture with Macquarie Infrastructure and Real Assets Inc. (MIRA) to develop certain of our oil and natural gas properties in the San Joaquin basin in exchange for a 90% working interest in the related properties (MIRA JV). MIRA funded 100% of the drilling and completion costs of agreed-upon wells in the drilling program. Our 10% working interest increases to 75% if MIRA receives cash distributions equal to a predetermined threshold return. The initial phase of the agreed-upon capital program was funded through December 31, 2020. Our consolidated results reflect only our working interest share in the productive wells.

BSP JV

In February 2017, we entered into a development joint venture with Benefit Street Partners (BSP) where BSP cumulatively contributed $200 million over a period of approximately two years in exchange for preferred interests in the BSP JV. BSP is entitled to preferential distributions and, if BSP receives cash distributions equal to a predetermined threshold, the preferred interest is automatically redeemed in full with no additional payment. At current prices, we believe BSP's preferred interest could be redeemed within the next twelve months. The funds contributed by BSP were used to develop certain of our oil and natural gas properties.

The BSP JV holds net profits interests in existing and future cash flow from certain of our properties and the proceeds from the net profits interests are used by the BSP JV to (1) pay quarterly minimum distributions to BSP, (2) make additional distributions to BSP until the predetermined threshold is achieved, and (3) pay for development costs within the project area, upon mutual agreement between members. Our consolidated results reflect the full operations of the BSP JV, with BSP's share of net income reported in net income attributable to noncontrolling interests on our consolidated statements of operations.

Midstream JV

Ares JV

In February 2018, our wholly-owned subsidiary California Resources Elk Hills, LLC (CREH) entered into a joint venture 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 (Elk Hills Power), and each of CREH and ECR held an equity interest in this entity.

On July 15, 2020, we entered into the Settlement Agreement with ECR and Ares which, among other things, granted us the right to acquire all of the equity interests of Elk Hills Power owned by ECR in exchange for (i) EHP Notes in the aggregate principal amount of $300 million, (ii) approximately 20.8% (subject to dilution) of common stock issued upon our emergence from bankruptcy, and (iii) approximately $2.0 million in cash. The Settlement Agreement also provided that all joint venture arrangements would be terminated upon exercise of this right.

We were deemed to have exercised the conversion right on October 27, 2020. Upon our emergence from bankruptcy, 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 this conversion, Elk Hills Power's limited liability company agreement was amended and restated.

We determined that the amended terms were substantively different such that the existing equity 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 accounting rules, the gain from the modification of the equity instrument was recorded to additional paid-in capital on our consolidated Predecessor balance sheet. However, as required by GAAP, the gain on the modification was included in our earnings per share calculations. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 17 Earnings per Share* for adjustments to net income (loss) attributable to common stock which includes a modification of noncontrolling interest.

Our consolidated statements of operations for the Predecessor reflects the operations of the Ares JV, with ECR's share of net income (loss) reported in net income attributable to noncontrolling interests. ECR's redeemable noncontrolling interests was reported in mezzanine equity due to an embedded optional redemption feature.

For more information on the Ares JV, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Joint Ventures.* For more information on the Settlement Agreement, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Chapter 11 Proceedings.*

Divestitures and Acquisitions

Divestitures

In May 2019, we sold 50% of our working interest and transferred operatorship in certain zones within our Lost Hills field, located in the San Joaquin basin, for total consideration in excess of $200 million, consisting of approximately $168 million in cash and a carried 200-well development program to be drilled through 2023 with an estimated value of $35 million (Lost Hills divestiture). We received cash proceeds of $164 million after transaction costs and purchase price adjustments, which were used to pay down our 2014 Revolving Credit Facility. The low commodity price environment in 2020 extended the time period of the carry through 2024.

In January 2020, we sold royalty interests and divested non-core assets resulting in $41 million of proceeds and no gain or loss was recognized. In 2018, we divested non-core assets resulting in $18 million of proceeds and a $5 million gain.

Acquisitions

In April 2018, we acquired from Chevron U.S.A., Inc. (Chevron) its share of the remaining working, surface and mineral interests in the approximately 47,000-acre Elk Hills unit (the Elk Hills transaction) for approximately $518 million, including $7 million of liabilities assumed relating to asset retirement obligations. We accounted for the Elk Hills transaction as a business combination and allocated $435 million to proved properties, $77 million to other property, plant and equipment and $6 million to materials and supplies. The consideration paid consisted of $460 million in cash and 2.85 million shares of our pre-emergence common stock issued at the close of the transaction (valued at $51 million).

As part of the Elk Hills transaction, Chevron reduced its royalty interest in one of our oil and natural gas properties by half and extended the time frame to invest the remainder of our capital commitment on that property by two years, to the end of 2022. As of December 31, 2020, our remaining commitment was approximately $12 million. In addition, the parties mutually agreed to release each other from pending claims with respect to the former Elk Hills unit.

In April 2018, we acquired an office building and land in Bakersfield, California for $48 million.

Additionally, we had several other acquisitions totaling approximately $6 million in 2019 and $39 million in 2018.

Seasonality

While certain aspects of our operations are affected by seasonal factors, such as energy costs, overall, seasonality has not been a material driver of changes in our earnings during the year.

Income Taxes

Net (loss) income before income taxes, for all periods presented, was generated solely from domestic operations. We did not record a significant income tax provision (benefit) in any of the periods presented, due to our valuation allowance.

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

	Successor	Predecessor		
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Years ended December 31,	
			2019	2018
U.S. federal statutory tax rate	(21)%	21%	21%	21%
State income taxes, net	(7)	7	7	6
Exclusion of income attributable to noncontrolling interests, net	—	(1)	(35)	(5)
Debt restructuring, net	—	(8)	—	—
Changes in tax attributes, net	—	7	(9)	(6)
Nondeductible compensation, net	—	—	3	—
Change in valuation allowance, net	27	(27)	14	(17)
Other, net	1	1	—	1
Effective tax rate	—%	—%	1%	—%

Our effective tax rate is primarily affected by state taxes, income included in our consolidated results which is taxed to noncontrolling interests, the benefit of tax credits, when available. Further, as a result of our emergence from bankruptcy, we wrote-off deferred tax assets because of the limitation on the realizability of our net operating loss and tax carryforwards as described further below. Given our income tax position, any item affecting our effective tax rate is generally offset by an equal change in the valuation allowance.

In connection with our emergence from bankruptcy and cancellation of claims, which were included in liabilities subject to compromise as of our emergence date, we generated cancellation of debt income for tax purposes which was excluded from taxable income under rules related to bankruptcy proceedings. In exchange for this exclusion, for federal purposes, we were required to reduce our net operating loss (NOL) and tax credit carryforwards and the tax basis of our assets, primarily property, plant and equipment. The primary driver of the income tax benefit related to the cancellation of our debt is due to the mechanics of attribute reduction for state combined income tax reporting purposes.

Our ability to utilize our remaining NOL, tax credit and interest expense carryforwards may be limited since we experienced an “ownership change” in connection with the restructuring process. Absent an applicable exception, if a corporation undergoes an ownership change, the amount of its NOLs and other carryforwards that may be used to reduce U.S. federal and state income tax obligations is subject to an annual limitation. Although an exception to the imposition of an annual limitation applies in Chapter 11 Cases under Section 382(l)(5) of the Internal Revenue Code of 1986, as amended, it is currently not likely if we will apply such section because if we experience a subsequent ownership change within two years of the Effective Date, any remaining net operating losses and certain other tax attributes, including interest expense carryforwards, may be subject to further and more severe limitations. Accordingly, the write-off of the benefit for our remaining NOLs and other carryforwards had the effect of increasing our effective tax rate in the Predecessor period. We are evaluating alternatives available in order to minimize the impact of the change in ownership that does not subject pre-emergence NOLs and other tax attributes to an ownership change.

Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit use of existing deferred tax assets. A significant piece of evidence evaluated is a history of operating losses. Such evidence limits our ability to consider other evidence such as projections for growth. As of December 31, 2020, we concluded that we could not realize, on a more-likely-than-not basis, any of our deferred tax assets and there is not sufficient evidence to support the reversal of all or any portion of this allowance. Given our recent and anticipated future earnings trends, we do not believe any significant amount of the valuation allowance as of December 31, 2020 will be released within the next 12 months. Changes in assumptions could materially affect the recognized amount of valuation allowance.

As of December 31, 2020, we had U.S. federal net operating loss carryforwards of approximately $17 million, which begin to expire in 2039. Our carryforward for business interest expense of $855 million does not expire.

As of December 31, 2020, we had California net operating loss carryforwards of approximately $2 billion, which begin to expire in 2026, and an insignificant amount of tax credit carryforwards.

For additional information on tax-related items, see information set forth in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 12 Income Taxes*.

Statement of Operations Analysis

Results of Oil and Natural Gas Operations

The following represents key operating data for our oil and natural gas operations, excluding corporate items, on a per Boe basis for the years ended December 31, 2020, 2019 and 2018:

	Successor	Predecessor		
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	2019	2018
Operating costs[(a)]	$ 18.19	$ 14.95	$ 19.16	$ 18.88
Operating costs, excluding effects of PSC-type contracts[(b)]	$ 16.86	$ 14.14	$ 17.70	$ 17.47
Field general and administrative expenses[(c)]	$ 1.12	$ 1.11	$ 1.20	$ 1.01
Field depreciation, depletion and amortization[(d)]	$ 4.95	$ 8.75	$ 9.40	$ 9.71
Field taxes other than on income[(e)]	$ 0.64	$ 3.10	$ 2.59	$ 2.42

(a) The decrease in operating costs in the Predecessor period in 2020 was primarily due to shut-in wells and lower activity in response to the lower price environment as well as workforce reductions and reduced work hours in the second quarter of 2020. Operating costs on a per barrel basis were higher in the Successor period as a result of moderately lower production volumes and higher workover and maintenance activity levels.

(b) As described in *Items 1 and 2 – Business and Properties – Operations – Production, Price and Cost History*, the reporting of our PSC-type contracts 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.

(c) Field general and administrative expenses increased in 2019 compared to 2018, primarily due to the Elk Hills transaction that occurred in April 2018 since certain costs are no longer recovered from our former working interest partner. Our 2019 costs include 12 months without such cost recovery compared to nine months without cost recovery in 2018.

(d) Field depreciation, depletion and amortization decreased in the Predecessor period in 2020 from prior years as a result of a lower depletable basis resulting from our asset impairment recorded in the first quarter. Field depreciation, depletion and amortization further declined in the Successor period due to a decrease in our depletable basis as a result of our fresh start fair value adjustments.

(e) Field taxes other than on income declined in the Successor period primarily resulting from reduced emissions compared to 2019 due to lower activity levels, including shut-in wells, and better-than-expected market pricing on the purchase of greenhouse gas emission credits.

Consolidated Results of Operations

The periods of 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 upon emergence from Chapter 11 bankruptcy and are not comparable to prior periods. We have combined these periods in 2020 to provide comparability of information to the years ended December 31, 2019 and 2018. While this combined presentation is not presented according to generally accepted accounting principles in the United States (GAAP) and no comparable GAAP measures are presented, management believes that providing this information is relevant and useful for making comparisons to the prior years. Where the combined amounts are not on a comparable basis to prior years (including depreciation, depletion and amortization and interest and debt expense, net and net loss (income) attributable from noncontrolling interests), our discussion addresses Predecessor and Successor results separately.

The following represents key operating data for consolidated operations for the periods presented (in millions):

	Successor	Predecessor	Combined	Predecessor	
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2020	Year ended December 31, 2019	Year ended December 31, 2018
Oil and natural gas sales[(a)]	$ 237	$ 1,092	$ 1,329	$ 2,270	$ 2,590
Net derivative (loss) gain from commodity contracts	(141)	91	(50)	(59)	1
Trading revenue	38	124	162	286	330
Electricity sales	15	86	101	112	111
Other revenue	3	14	17	25	32
Operating costs	(114)	(511)	(625)	(895)	(912)
General and administrative expenses	(40)	(212)	(252)	(290)	(299)
Depreciation, depletion and amortization	(34)	(328)	(362)	(471)	(502)
Asset impairment	—	(1,736)	(1,736)	—	—
Taxes other than on income	(10)	(134)	(144)	(157)	(149)
Exploration expense	(1)	(10)	(11)	(29)	(34)
Trading costs	(24)	(78)	(102)	(201)	(250)
Electricity cost of sales	(10)	(53)	(63)	(68)	(61)
Transportation costs	(8)	(35)	(43)	(40)	(36)
Other expenses, net	(17)	(89)	(106)	(54)	(52)
Reorganization items, net	(3)	4,060	4,057	—	—
Interest and debt expense, net	(11)	(206)	(217)	(383)	(379)
Net gain on early extinguishment of debt	—	5	5	126	57
Gain on asset divestitures	—	—	—	—	5
Other non-operating expenses	(5)	(84)	(89)	(72)	(23)
Income (loss) before income taxes	(125)	1,996	1,871	100	429
Income tax provision	—	—	—	(1)	—
Net income (loss)	(125)	1,996	1,871	99	429
Net loss (income) attributable to noncontrolling interests	$ 2	$ (107)	$ (105)	$ (127)	$ (101)
Net (loss) income attributable to common stock	$ (123)	$ 1,889	$ 1,766	$ (28)	$ 328
Adjusted net income (loss)[(a)]	$ 28	$ (285)	$ (257)	$ 70	$ 61
Adjusted EBITDAX[(a)]	$ 83	$ 406	$ 489	$ 1,142	$ 1,117

(a) Adjusted net income (loss) and Adjusted EBITDAX are non-GAAP measures. See the *Non-GAAP Financial Measures* section below for a reconciliations to their nearest GAAP measures.

Year Ended December 31, 2020 (Combined) vs. 2019

Oil and natural gas sales – Oil and natural gas sales, excluding the impact of settled hedges, were $1,329 million for the combined period of January 1, 2020 through December 31, 2020, which is a decrease of 41%, or $941 million, compared to $2,270 million in 2019. The decrease was due to changes in realized prices and production as reflected in the following table:

	Oil	NGLs	Natural Gas	Total
		(in millions)		
Year ended December 31, 2019	$ 1,884	$ 179	$ 207	$ 2,270
Changes in realized prices	(666)	(23)	(42)	(731)
Changes in production	(168)	(21)	(21)	(210)
Year ended December 31, 2020	$ 1,050	$ 135	$ 144	$ 1,329

Note: See *Production and Prices* for average benchmark and realized prices, realizations and production.

The effect of settled hedges is not included in the table above. Proceeds from settled hedges were $107 million for the combined year ended December 31, 2020. For the year ended December 31, 2019, proceeds from settled hedges were $111 million.

Net derivative (loss) gain from commodity contracts – Net derivative loss from commodity contracts was $50 million for the combined year ended December 31, 2020 compared to $59 million for same period of 2019, representing an overall change of $9 million as reflected in the following table. The non-cash changes in the fair value of our outstanding derivatives resulted from the positions held as well as the relationship between contract prices and the associated forward curves at the end of each year.

	Successor	Predecessor	Combined	Predecessor
(in millions)	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2020	Year ended December 31, 2019
Non-cash derivative (loss) gain, excluding noncontrolling interest	$ (138)	$ (19)	$ (157)	$ (166)
Non-cash derivative (loss) gain, noncontrolling interest	(2)	2	—	(4)
Total non-cash changes	(140)	(17)	(157)	(170)
Net (payments) proceeds on commodity derivatives	(1)	108	107	111
Net derivative (loss) gain from commodity contracts	$ (141)	$ 91	$ (50)	$ (59)

Trading revenue – Trading revenues were a combined $162 million for the year ended December 31, 2020, a decrease of $124 million, or 43% from $286 million during the year ended December 31, 2019. The decrease was due to lower volumes and prices related to our natural gas trading activities. The decline in volumes and prices were impacted by a decrease in energy demand resulting from the pandemic and milder temperatures in 2020.

Operating costs – Operating costs for the combined year ended December 31, 2020 was $625 million, which was a decrease of $270 million or 30% from $895 million for the same period in 2019. The decrease was primarily attributable to efficiencies and streamlining of our operations and reduced operating costs from shut-in wells as well as lower activity levels such as downhole maintenance. Operating costs also declined as a result of our workforce reductions and reduced work schedules during April and May 2020.

General and administrative expenses – Our general and administrative expenses (G&A) were $252 million for the combined year ended December 31, 2020, which was a decrease of $38 million from $290 million in the year ended December 31, 2019. The decrease in G&A expenses resulted from workforce reductions, cost saving efforts, a decline in spending across a number of cost categories and reduced work hours in April and May 2020. These savings were partially offset by the cost of obtaining additional directors and officers insurance related to our Chapter 11 Cases, lower capitalized salary costs as a result of suspending our capital program beginning in March 2020 as well a slight increase in employee incentive awards due to changes to the variable portion of our incentive compensation program in May 2020, which had the effect of increasing our cash-settled awards to target and achieving a higher payout on performance metrics.

Depreciation, depletion and amortization – Depreciation, depletion and amortization during the Successor period reflects fair value adjustments recorded as part of fresh start accounting on our emergence date. For further detail about fresh start accounting, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Fresh Start Accounting*.

The decrease in depreciation, depletion and amortization on an annualized basis for the Predecessor period ended October 31, 2020 from 2019 was predominately due to a decrease in our depletable basis as a result of our asset impairment recorded in the first quarter of 2020, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 13 Asset Impairments*.

Asset impairments – We recorded an impairment charge in March 2020 due to the sharp drop in commodity prices at the end of the first quarter of 2020. The 2020 Predecessor period includes this impairment charge of $1.7 billion, of which $1.5 billion related to certain of our proved properties and approximately $228 million related to unproved acreage that is no longer included in our development plans.

The fair values of our proved oil and natural gas properties were determined as of the date of the assessment using discounted cash flow models, which included estimates of future oil and natural gas production, index prices based on available forward curves and internally generated price forecasts thereafter, pricing adjustments for differentials, estimated future operating costs and capital development plans. We used a market-based weighted average cost of capital to discount the future net cash flows. For further detail about our first quarter 2020 asset impairment, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 13 Asset Impairments*.

Exploration expense – Exploration expense decreased to $11 million for the combined year ended December 31, 2020 compared to $29 million in the same period of 2019. The decrease was due to limited exploration activity in 2020 as a result of the lower commodity price environment.

Trading costs – Natural gas purchases related to trading activity were $102 million for the combined year ended December 31, 2020, which was a decrease of $99 million or 49% from $201 million in 2019. The decrease was predominantly the result of lower volume and prices related to our natural gas trading activities. The decline in volumes and prices were impacted by a decrease in energy demand resulting from the pandemic and milder temperatures in 2020.

Other expenses, net – Other expenses, net was $106 million for the combined year ended December 31, 2020, which was an increase of $52 million from $54 million in 2019. The increase was largely the result of a one-time deficiency payment made in April 2020 in connection with an expiring pipeline delivery contract and employee termination charges related to our August 2020 workforce reduction and the departure of our former chief executive officer in December 2020.

Reorganization items, net – We recognized a $4.1 billion net gain in the 2020 Predecessor period primarily related to the cancellation of our pre-emergence debt and the associated write-off of the unamortized balance of deferred gain, original issue discounts and deferred issuance costs partially offset by legal, professional and other fees, including debtor-in-possession financing costs, which were incurred during our bankruptcy proceedings. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Chapter 11 Proceedings* for additional information about reorganization items, net.

Interest and debt expense, net – Interest and debt expense, net for the Successor period includes interest on our Revolving Credit Facility, Second Lien Notes and EHP Notes as well as amortization of debt issuance costs as shown in the table below. We expect that our future interest expense will generally be in line with the interest on debt for the Successor period on an annualized basis.

Interest and debt expense, net decreased in the Predecessor period of 2020 compared to the year ended December 31, 2019 primarily due to ceasing to record interest expense on our debt as of the petition date and the subsequent discharge of our debt upon emergence from bankruptcy. Additionally, we decreased the amount of interest expense capitalized in the 2020 Predecessor period as compared to 2019 primarily due to decreased drilling activity. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Debt* for additional information on our credit agreements.

The table below shows interest and debt expense, net for the Successor and Predecessor periods (in millions):

	Successor	Predecessor	Predecessor
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2019
Interest expense on debt	$ 10	$ 223	$ 437
Amortization of deferred gain	—	(39)	(70)
Amortization of debt issuance	1	29	28
Other interest	—	1	2
Capitalized interest	—	(8)	$ (14)
Interest and debt expense, net	$ 11	$ 206	$ 383

Net gain on early extinguishment of debt – We repurchased debt in the first quarter of 2020 and recognized a net gain on early extinguishment of debt for the combined year ended December 31, 2020 of $5 million, which is a decrease of $121 million from $126 million during the same period in 2019. The decrease was due to lower debt repurchase activity in 2020.

Other non-operating expenses – Other non-operating expenses for the combined year ended December 31, 2020 increased $17 million to $89 million, compared to $72 million for the same period of 2019. This increase was primarily the result of legal, professional and other fees associated with the preparation of the Chapter 11 Cases, incurred prior to our petition date.

Net loss (income) attributable to noncontrolling interests – Upon emergence from bankruptcy, we acquired all of ECR's member interests in the Ares JV; therefore, the allocation of net loss (income) to noncontrolling interest holders in the Successor period is not comparable to the Predecessor periods.

The net loss allocated to the noncontrolling interest holder in the Successor period primarily relates to non-cash losses on derivatives.

The decrease in net income allocated to noncontrolling interests in the Predecessor period of 2020 included ten months as compared to twelve months in 2019 due to the acquisition of ECR's interest in the Ares JV at emergence and to a lesser extent, lower revenue from the net profits interest held by the BSP JV due to a decline in commodity prices between periods.

See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Joint Ventures* for additional information on the Ares JV.

Year Ended December 31, 2019 vs. 2018

See *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Statement of Operations Analysis* in our 2019 Form 10-K for our analysis of the changes in our consolidated statements of operations for the year ended December 31, 2019 compared to December 31, 2018.

Non-GAAP Financial Measures

Adjusted net income (loss) – Our results of operations, which are presented in accordance with U.S. generally accepted accounting principles (GAAP), can include the effects of unusual, out-of-period and infrequent transactions and events affecting earnings that vary widely and unpredictably (in particular certain non-cash items such as derivative gains and losses) in nature, timing, amount and frequency. Therefore, management uses a measure called adjusted net income (loss) that excludes those items. This measure is not meant to disassociate these items from management's performance but rather is meant to provide useful information to investors interested in comparing our performance between periods. Reported earnings are considered representative of management's performance over the long term. Adjusted net income (loss) is not considered to be an alternative to net income (loss) reported in accordance with GAAP.

The following table presents a reconciliation of the GAAP financial measure of net income (loss) to the non-GAAP financial measure of adjusted net income (loss) and presents the GAAP financial measure of net income (loss) attributable to common stock per diluted share and the non-GAAP financial measure of adjusted net income (loss) per diluted share (in millions, except per share data):

	Successor	Predecessor	Combined	Predecessor	
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2020	Year ended December 31, 2019	Year ended December 31, 2018
Net income (loss)	$ (125)	$ 1,996	$ 1,871	$ 99	$ 429
Net income attributable to noncontrolling interests	2	(107)	(105)	(127)	(101)
Net (loss) income attributable to common stock	(123)	1,889	1,766	(28)	328
Unusual, infrequent and other items:					
Asset impairment	—	1,736	1,736	—	—
Reorganization items, net	3	(4,060)	(4,057)	—	—
Legal, professional and other fees related to our reorganization	—	65	65	—	—
Non-cash derivative loss (gain) from commodities, excluding noncontrolling interest	138	19	157	166	(224)
Non-cash derivative loss from interest-rate contracts	—	—	—	4	6
Severance and termination costs	5	10	15	47	4
Deficiency payment on a pipeline delivery contract	—	20	20	—	—
Power plant maintenance	—	7	7	—	—
Write-off of deferred financing costs	—	4	4	4	4
Incentive and retention award modification	—	4	4	—	—
Net gain on early extinguishment of debt	—	(5)	(5)	(126)	(57)
Gain on asset divestitures	—	—	—	—	(5)
Rig termination expenses	1	4	5	3	8
Ad valorem late payment penalties	—	4	4		
Other, net	4	18	22	—	(3)
Total unusual, infrequent and other items	151	(2,174)	(2,023)	98	(267)
Adjusted net income (loss)	$ 28	$ (285)	$ (257)	$ 70	$ 61
Net (loss) income attributable to common stock per diluted share	$ (1.48)	$ 40.42	—	$ (0.57)	$ 6.77
Adjusted net income (loss) per diluted share	$ 0.34	$ (2.98)	—	$ 1.40	$ 1.27

Adjusted EBITDAX – We define Adjusted EBITDAX as earnings before interest expense; income taxes; depreciation, depletion and amortization; exploration expense; other unusual, infrequent and out-of-period items; and other non-cash items. We believe this measure provides useful information in assessing our financial condition, results of operations and cash flows and is widely used by the industry, the investment community and our lenders. Although this is a non-GAAP measure, the amounts included in the calculation were computed in accordance with GAAP. Certain items excluded from this non-GAAP measure are significant components in understanding and assessing our financial performance, such as our cost of capital and tax structure, as well as depreciation, depletion and amortization of our assets. This measure should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP. A version of Adjusted EBITDAX is a material component of certain of our financial covenants under our Revolving Credit Facility and is provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP.

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

	Successor	Predecessor	Combined	Predecessor	
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2020	Year ended December 31, 2019	Year ended December 31, 2018
Net income (loss)	$ (125)	$ 1,996	$ 1,871	$ 99	$ 429
Interest and debt expense, net	11	206	217	383	379
Depreciation, depletion and amortization	34	328	362	471	502
Exploration expense	1	10	11	29	34
Unusual, infrequent and other items	151	(2,174)	(2,023)	98	(267)
Non-cash items					
Accretion expense	8	33	41	36	27
Stock-settled compensation	—	6	6	13	15
Post-retirement medical and pension	1	3	4	8	4
Other non-cash items	2	(2)	—	5	(6)
Adjusted EBITDAX	$ 83	$ 406	$ 489	$ 1,142	$ 1,117

The following table sets forth a reconciliation of the GAAP measure of net cash provided by operating activities to the non-GAAP financial measure of Adjusted EBITDAX (in millions):

	Successor	Predecessor	Combined	Predecessor	
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2020	Year ended December 31, 2019	Year ended December 31, 2018
Net cash provided (used) by operating activities	$ (12)	$ 118	$ 106	$ 676	$ 461
Cash interest	8	87	95	439	441
Exploration expenditures	1	10	11	18	17
Working capital changes	86	191	277	8	199
Other, net	—	—	—	1	(1)
Adjusted EBITDAX	$ 83	$ 406	$ 489	$ 1,142	$ 1,117

Liquidity and Capital Resources

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 net cash provided by operating activities of $106 million for the combined year ended December 31, 2020 decreased $570 million, or 84%, from $676 million for the same period in 2019. This decrease was primarily driven by a lower commodity price environment, declining production and $113 million of payments of professional and other fees related to our bankruptcy proceedings during 2020. This decrease was partially offset by a reduction in our cost structure due to lower activity levels in 2020, including the effect of shut-in wells, operational efficiencies and workforce reductions as compared to 2019 as well as reduced cash interest between comparative periods.

Cash flows from investing activities – Our net cash used in investing activities was $37 million in the combined year ended December 31, 2020, which was a decrease of $357 million, or 91%, from $394 million for the same period in 2019. The decrease primarily related to reducing our capital investment in 2020 to a level necessary to maintain the mechanical integrity of our facilities to operate them in a safe and environmentally responsible manner partially offset by a decrease in proceeds from asset divestitures.

The table below summarizes net cash used in investing activities (in millions):

	Successor	Predecessor	Combined	Predecessor
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2020	Year ended December 31, 2019
Capital investments	$ (7)	$ (40)	$ (47)	$ (455)
Changes in capital investment accruals	(1)	(24)	(25)	(85)
Acquisitions, divestitures and other	1	34	35	146
Net cash used in investing activities	$ (7)	$ (30)	$ (37)	$ (394)

Cash flows from financing activities – Our net cash used in financing activities was $58 million in the combined year ended December 31, 2020. Uses of cash in 2020 related to our debt transactions including $518 million net repayments on our 2014 Revolving Credit Facility (some of which was repaid with debtor-in-possession financing) and $100 million used to payoff of our 2020 Senior Notes in the first quarter. At emergence, we borrowed $200 million under our Second Lien Term Loan, the proceeds of which were used to repay a portion of our debtor-in-possession financing. The outstanding balance on our Revolving Credit Facility was $99 million as of December 31, 2020. As a result of our bankruptcy proceedings, we incurred $45 million in debt financing and issuance costs. We also made $104 million of distributions to noncontrolling interest holders in the Predecessor period of 2020, which included payments to our former noncontrolling interest holder, ECR. Our distributions to noncontrolling interest holders was $30 million in the Successor period. We raised proceeds of $446 million from an equity issuance at the time of our emergence from bankruptcy.

Our net cash used in financing activities for the year ended December 31, 2019 was $282 million and included net repayments of $23 million on our 2014 Revolving Credit facility, $102 million in net distributions to noncontrolling interest holders and $156 million used to repurchase our Second Lien Notes.

The table below summarizes net cash (used) provided by financing activities for the years ended December 31, 2020 and 2019 (in millions):

	Successor	Predecessor	Combined	Predecessor
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2020	Year ended December 31, 2019
Debt transactions	$ (126)	$ (241)	$ (367)	$ (181)
(Distributions to) contributions from noncontrolling interest holders, net	(30)	(104)	(134)	(102)
Issuance of common stock	—	446	446	4
Other	—	(3)	(3)	$ (3)
Net cash (used) provided by financing activities	$ (156)	$ 98	$ (58)	$ (282)

Liquidity

Our primary sources of liquidity and capital resources are cash flows from operations, cash on hand and available borrowing capacity under our Revolving Credit Facility. We emerged from our bankruptcy with a strong balance sheet and low leverage. We have substantially revamped our cost structure while maintaining sustainable operations. We consider our low leverage and ability to control costs to be a core strength and strategic advantage, which we are focused on maintaining. At current commodity prices and the 2021 capital program described below, we expect to generate positive free cash flow, which may be used to (i) increase investments in our drilling program to accelerate value, (ii) pay dividends or buy back stock to the extent permitted under our Revolving Credit Facility, or (iii) maintain cash on our balance sheet. We may be required to begin paying income taxes if Brent prices remain above $55 per barrel for a sustained period. 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. We believe we have sufficient sources of cash to meet our obligations for the next twelve months.

As of December 31, 2020, we had liquidity of $335 million, which consisted of $28 million in unrestricted cash and $307 million of available borrowing capacity under our Revolving Credit Facility. After giving effect to our January 2021 debt issuance discussed below, we had on a pro forma basis liquidity of $425 million, which consisted of $28 million in unrestricted cash and $397 million of available borrowing capacity under our Revolving Credit Facility.

In January 2021, we completed a private offering of $600 million in aggregate principal amount of our 7.125% senior unsecured notes due 2026 (Senior Notes). The net proceeds of $590 million were used to repay in full our Second Lien Term Loan and our EHP Notes, with the remaining proceeds used to pay down a portion of the outstanding borrowings under our Revolving Credit Facility. The proceeds received were net of $10 million in debt issuance and transaction costs. For more information on this debt issuance, refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 19 Subsequent Events* and for more information on our debt, refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Debt.*

The following table presents our pro forma long-term debt assuming the January 2021 debt issuance and related use of proceeds occurred on December 31, 2020:

	Actual December 31, 2020	Transaction Adjustments	Pro Forma
		(in millions)	
Revolving Credit Facility	$ 99	$ (90)	$ 9
Second Lien Term Loan	200	(200)	—
EHP Notes	300	(300)	—
Senior Notes	—	600	600
Face amount of long-term debt	599	10	609
Unamortized debt issuance costs	(2)	(8)	(10)
Total long-term debt	$ 597	$ 2	$ 599

As of December 31, 2020, we were in compliance with all of the covenants of our new Revolving Credit Facility.

For a description of the terms and conditions of our long-term indebtedness, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Debt.*

Derivatives and Hedging Activities

Commodity Contracts

The credit agreement governing our senior debtor-in-possession facility during bankruptcy, which was paid in full and terminated on the Effective Date, required us to enter into hedging arrangements covering at least 25% of our share of expected crude oil production for the next twelve months. On July 24, 2020, we entered into various instruments to satisfy this requirement. Our post-emergence Revolving Credit Facility and Second Lien Term Loan require us to maintain a significantly higher amount of hedges on expected crude oil production, as described in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Debt*. As described above, our Second Lien Term Loan was paid in full in January 2021.

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. We did not have any commodity derivatives designated as accounting hedges as of and during the combined year ended December 31, 2020.

We currently have the following Brent-based crude oil contracts, as of February 28, 2021:

	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022	January - October 2023
Sold Calls:						
Barrels per day	19,028	33,537	36,362	36,700	30,783	17,758
Weighted-average price per barrel	$ 47.88	$ 48.73	$ 50.31	$ 60.70	$ 59.37	$ 58.01
Purchased Puts						
Barrels per day	39,148	37,872	36,617	35,483	30,783	17,758
Weighted-average price per barrel	$ 41.88	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00
Sold Puts						
Barrels per day	15,659	15,149	14,647	14,193	3,042	—
Weighted-average price per barrel	$ 35.97	$ 31.41	$ 30.00	$ 32.00	$ 32.00	$ —
Swaps						
Barrels per day	8,524	9,639	9,063	8,922	6,576	5,919
Weighted-average price per barrel	$ 44.54	$ 46.35	$ 47.18	$ 48.57	$ 46.29	$ 47.57

The BSP JV entered into crude oil derivatives for insignificant volumes through 2021 that are included in our consolidated results but not in the above table. The BSP JV also entered into natural gas swaps for insignificant volumes for periods through May 2021. The hedges entered into by the BSP JV could affect the timing of the reversion of BSP’s preferred interest.

Capital Program

We seek to create value by investing part of our operating cash flow back into our business. We respond to economic conditions by adjusting the amount and allocation of our capital program while continuing to identify efficiencies and cost savings. Because we own or control substantially all of our assets, the amount and timing of capital expenditures is within our control, subject to our discretion and may be adjusted during the year depending on commodity prices and other factors. We retain the flexibility to defer planned capital expenditures depending on a variety of factors, including, but not limited to, prevailing and anticipated prices for oil, natural gas and NGLs, the success of our drilling program, operating costs and other general market conditions.

We focus our capital program on oil projects that provide high margins and low decline rates, prioritizing projects with quick paybacks and full-cycle returns to maximize our free cash flow. Our technical teams are consistently working to enhance value by improving the economics of our inventory through detailed geologic studies as well as application of more effective and efficient drilling and completion techniques. We regularly monitor internal performance and external factors and adjust our capital investment program with the objective of creating the most value from our asset portfolio. We believe investing in these projects will generate positive cash flow allowing us to fund future capital programs with a high oil mix. Our low decline rates compared to our industry peers together with our high level of operational control give us the flexibility to adjust the level of our capital investments as circumstances warrant.

2020 Capital Program

We entered 2020 with an internally funded capital program plan of $100 million to $300 million. In March 2020, we reduced our capital investment to a level that intended to maintain the mechanical integrity of our facilities to operate in a safe and environmentally responsible manner in response to the collapse in crude oil prices and ceased all field development and growth projects. We made $40 million of internally funded capital investments during the 2020 Predecessor period and $7 million during the Successor period.

Our JV partners invested $93 million during the year ended December 31, 2020 as shown in the table below. For further information regarding the Alpine JV see *Joint Ventures* above.

The table below sets forth our internally funded capital investments by activity type included in our consolidated financial statements for the combined year ended December 31, 2020 and investments in our fields by our JV partners (in millions):

	Drilling	Workovers	Facilities	Exploration	Other	Total Capital Investments
Internally funded	$ 15	$ 9	$ 22	$ —	$ 1	$ 47
Capital investments not included in our financial statements						
MIRA-funded capital	1	—	—	—	$ —	$ 1
Alpine-funded capital	92	—	—	—	$ —	$ 92
Total capital investments	$ 108	$ 9	$ 22	$ —	$ 1	$ 140

2021 Capital Program

Our capital program will be dynamic in response to oil market volatility while focusing on maintaining strong liquidity and maximizing our free cash flow. The 2021 capital program will target reinvestment of approximately 50% of anticipated available cash flow from operations at current commodity prices. Our 2021 capital program is anticipated to be between $200 million and $225 million, including approximately $40 million of mechanical integrity and midstream turnaround activities deferred from 2020 to 2021. The current plan anticipates CRC to gradually raise quarterly investment throughout the year if the commodity environment continues to strengthen. If commodity prices decline significantly from current levels, we may need to adjust our capital program in response to market conditions.

Off-Balance-Sheet Arrangements

We have no off-balance-sheet arrangements other than the purchase obligations described in the *Contractual Obligations* section below.

Contractual Obligations

The table below summarizes our on- and off- balance sheet obligations as of December 31, 2020.

	Payments Due by Year				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
			(in millions)		
On-Balance Sheet					
Long-term debt[(a)]	$ 599	$ —	$ —	$ 299	$ 300
Interest on long-term debt[(b)]	257	43	86	79	49
Pension and postretirement[(c)]	221	19	23	19	160
Operating and finance leases[(d)]	49	8	15	11	15
Other long-term liabilities	9	3	6	—	—
Off-Balance Sheet					
Purchase obligations[(e)]	186	42	85	12	47
Total[(f)]	$ 1,321	$ 115	$ 215	$ 420	$ 571

(a) In performing the calculation, the Revolving Credit Facility borrowings outstanding at December 31, 2020 of $99 million were assumed to be outstanding for the entire term of the agreement. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Debt* for more information. On January 20, 2021, we completed an offering of $600 million aggregate principal amount of the Senior Notes. We used the net proceeds to repay in full our Second Lien Term Loan and EHP Notes, with the remainder of the net proceeds used to repay a portion of the outstanding borrowings under the Revolving Credit Facility. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 19 Subsequent Events* for more information.

(b) The calculation of cash interest payments on our variable interest-rate debt assumes the interest rate at December 31, 2020 will continue for the entire term. This amount excludes the effects of the January 2021 refinancing.

(c) Represents undiscounted future obligations for defined benefit and supplemental plans.

(d) Our operating leases include commercial office space, fleet vehicles and certain facilities. Our finance leases include information technology equipment and are not material to our consolidated financial statements taken as a whole.

(e) Amounts include payments that will become due under long-term agreements to purchase goods and services used in the normal course of business primarily including pipeline capacity and land leases. Purchase obligations for pipeline capacity are based on contractual volumes and current market rates for that firm transportation capacity during the contract period. Land leases reflect obligations for fixed payments under our term contracts. Also included is a commitment to invest approximately $12 million in evaluation and development activities at one of our oil and natural gas properties prior to January 1, 2023. Any deficiency in meeting this capital investment obligation would need to be paid in cash.

(f) This table does not include our asset retirement obligations. 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.

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, 2020 and 2019 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 determined that former lessees, including our former parent, Occidental Petroleum Corporation (Oxy) with an approximately 35% share, are responsible for accrued decommissioning obligations associated with these offshore platforms. Oxy notified us of the claim under the indemnification provisions of the Separation and Distribution Agreement between us and Oxy. We are currently evaluating this claim.

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 10 Lawsuits, Claims, Commitments and Contingencies.*

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates include property, plant and equipment and fair value measurements. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 1 Nature of Business, Summary of Significant Accounting Policies and Other* for details on these critical accounting policies and estimates that involve management's judgment and that could result in a material impact to the consolidated financial statements due to the levels of subjectivity and judgment.

Significant Accounting and Disclosure Changes

See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Accounting and Disclosure Changes* for a discussion of new accounting standards.

FORWARD-LOOKING STATEMENTS

The information included herein contains forward-looking statements that involve risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects. Such statements include those regarding our expectations as to our future:

- financial position, liquidity, cash flows and results of operations
- business prospects
- transactions and projects
- operating costs
- operations and operational results including production, hedging and capital investment
- budgets and maintenance capital requirements
- reserves
- type curves
- expected synergies from acquisitions and joint ventures

Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. While we believe assumptions or bases underlying our expectations are reasonable and make them in good faith, they almost always vary from actual results, sometimes materially. We also believe third-party statements we cite are accurate but have not independently verified them and do not warrant their accuracy or completeness. Factors (but not necessarily all the factors) that could cause results to differ include:

- our ability to execute our business plan post-emergence;
- the volatility of commodity prices and the potential for sustained low oil, natural gas and natural gas liquids prices;
- impact of our recent emergence from bankruptcy on our business and relationships;
- debt limitations on our financial flexibility;
- insufficient cash flow to fund planned investments, interest payments on our debt, debt repurchases or changes to our capital plan;
- insufficient capital or liquidity, including as a result of lender restrictions, unavailability of capital markets or inability to attract potential investors;
- limitations on transportation or storage capacity and the need to shut-in wells;
- inability to enter into desirable transactions, including acquisitions, asset sales and joint ventures;
- our ability to utilize our net operating loss carryforwards to reduce our income tax obligations;
- legislative or regulatory changes, including those related to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases (GHGs) or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products;
- joint ventures and acquisitions and our ability to achieve expected synergies;
- the recoverability of resources and unexpected geologic conditions;
- incorrect estimates of reserves and related future cash flows and the inability to replace reserves;
- changes in business strategy;
- production-sharing contracts’ effects on production and unit operating costs;
- the effect of our stock price on costs associated with incentive compensation;
- effects of hedging transactions;
- equipment, service or labor price inflation or unavailability;
- availability or timing of, or conditions imposed on, permits and approvals;
- lower-than-expected production, reserves or resources from development projects, joint ventures or acquisitions, or higher-than-expected decline rates;
- disruptions due to accidents, mechanical failures, power outages, transportation or storage constraints, natural disasters, labor difficulties, cyber-attacks or other catastrophic events;
- pandemics, epidemics, outbreaks, or other public health events, such as the COVID-19; and
- factors discussed in *Part I, Item 1A – Risk Factors.*

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, whether as a result of new information, future events or otherwise, except as required by applicable law.

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. In 2021, we expect that price changes at current levels of production, excluding hedge settlements, would affect our pre-tax annual income and cash flows as follows (in millions):

Pre-tax 2021 Price Sensitivities	
$1 change in Brent index – Oil[(a)]	$19.30
$1 change in Brent index – NGLs	$ 2.81
$0.10 change in NYMEX – Natural gas[(b)]	$ 2.94

(a) Assumes no hedges.
(b) Amount includes the offsetting effect of gas used in our operations.

Currently, due to our income tax position, there is no difference between the impact of commodity price changes on our income and cash flows. These price-change sensitivities include the impact on income of volume changes under PSC-type contracts. If production and price levels change in the future, the sensitivity of our results to prices also will change.

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, 2020, we had net liabilities of $56 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. A 10% increase or decrease in the fair value of our net derivative assets would affect pre-tax earnings by approximately $6 million.

A summary of our Brent-based crude oil derivative contracts through October 2023 are included in *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources, Derivatives and Hedging Activities*.

Counterparty Credit Risk

Our counterparty credit risk relates primarily to trade receivables and derivative financial instruments. Credit exposure for each customer is monitored for outstanding balances and current activity. For trade receivables, no single purchaser accounted for more than 23% of total revenues for the year ended December 31, 2020. We actively manage our credit risk by selecting counterparties that we believe to be financially sound and continue to monitor their financial health. Our two largest purchasers, which make up approximately 44% of our revenue for the combined year ended December 31, 2020 currently have investment grade credit ratings. 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 actively manage this credit risk by selecting counterparties that we believe to be financially strong and continue to monitor their financial health. Concentration of credit risk is regularly reviewed to ensure that counterparty credit risk is adequately diversified.

Interest-Rate Risk

As of December 31, 2020, we had borrowings of $99 million outstanding under our Revolving Credit Facility, which bears interest at a variable interest rate, which at December 31, 2020 was 5.5% (ABR) and 4.25% (LIBOR) per annum. As of December 31, 2020 we had $200 million of borrowings outstanding under our Second Lien Term Loan and $300 million of borrowings outstanding under our EHP Notes. The Second Lien Term Loan bore interest at a variable rate, which at December 31, 2020 was 10% per annum. The EHP Notes bore interest 6.0% per annum through the fourth anniversary of issuance, increasing to 7.0% per annum after the fifth anniversary of issuance and to 8.0% per annum after the fifth anniversary of issuance.

As discussed in *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources, Debt,* we issued $600 million of Senior Notes in January 2021 the net proceeds of which were used to repay in full our Second Lien Term Loan and repay all the outstanding EHP Notes with the remaining $90 million used to repay a portion of the outstanding borrowings under our Revolving Credit Facility. Our new Senior Notes bear interest at a fixed rate of 7.125% per annum.

The following table shows the face value and fair value of our fixed- and variable-rate debt pro forma for our January 2021 debt offering, as of December 31, 2020 as illustrated in *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources*:

Year of Maturity	**U.S. Dollar Fixed-Rate Debt**	**U.S. Dollar Variable-Rate Debt**	**Total**
		(in millions)	
2021	$ —	$ —	$ —
2022	—	—	—
2023	—	—	—
2024	—	9	9
2025	—	—	—
2026	600	—	600
Total	$ 600	$ 9	$ 609
Weighted-average interest rate	7.125%	4.88%	7.09%
Fair value	$ 600	$ 9	$ 609

A one percent change in the interest rate on the borrowings outstanding under our Revolving Credit Facility would result in an insignificant change in annual interest expense.

In May 2018, we entered into derivative contracts that limit our interest rate exposure with respect to $1.3 billion of our variable-rate indebtedness. These interest-rate contracts reset monthly and require the counterparties to pay any excess interest owed on such amount in the event the one-month LIBOR exceeds 2.75% for any monthly period prior to May 4, 2021. We have not received any settlement payments under these interest-rate contracts.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors

California Resources Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of California Resources Corporation and subsidiaries (the Company) as of December 31, 2020 (Successor) and 2019 (Predecessor), the related consolidated statements of operations, comprehensive income, equity, and cash flows for the periods from November 1, 2020 to December 31, 2020 (Successor) and from January 1, 2020 to October 31, 2020 (Predecessor) and for each of the years in the two-year period ended December 31, 2019 (Predecessor), and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 (Successor) and 2019 (Predecessor), and the results of its operations and its cash flows for the periods from November 1, 2020 to December 31, 2020 (Successor) and from January 1, 2020 to October 31, 2020 (Predecessor) and for each of the years in the two-year period ended December 31, 2019 (Predecessor), in conformity with U.S. generally accepted accounting principles.

Change in Accounting Principle

As discussed in Note 4 to the consolidated financial statements, the Company changed its method of accounting for leases as of January 1, 2019 due to the adoption of Accounting Standards Codification (ASC) Topic 842, *Leases*.

New Basis of Presentation

As discussed in Notes 2 and 3 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, 2020 and for the Successor period have been prepared in conformity with ASC Topic 852, *Reorganizations*, with the Company's assets, liabilities and capital structure having carrying amounts that are not comparable with prior periods.

Basis for Opinion

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (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 $34 million and $328 million for the periods from November 1, 2020 to December 31, 2020 (Successor) and from January 1, 2020 to October 31, 2020 (Predecessor), respectively. 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 reserve engineers as well as the external reserve engineers and external engineering firm, (2) the knowledge, skills, and ability of the Company's internal and external reserve engineers, and (3) the relationship of the external reserve engineers and external engineering firm 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.

Recoverability of proved oil and gas properties

As discussed in Notes 1, 5 and 13 to the consolidated financial statements, the Company periodically assesses their proved oil and gas properties for triggering events that could indicate impairment. If a triggering event is identified, the Company performs an undiscounted cash flows analysis to evaluate the recoverability of those oil and gas properties. When the carrying amount of oil and gas properties exceeds its estimated undiscounted future cash flows, an impairment loss is calculated as the excess of the oil and gas properties' net book value over its estimated fair value. The Company recognized an impairment loss of $1,487 million on proved oil and gas properties during the period from January 1, 2020 to October 31, 2020 (Predecessor). Key inputs used in the Company's impairment assessment include estimates of future production, commodity prices inclusive of market differentials, operating and development costs, and a discount rate.

We identified the assessment of recoverability of proved oil and gas properties as a critical audit matter due to the judgment inherent in estimating the future cash flows. Specifically, complex auditor judgment was required to evaluate key assumptions used to estimate the future cash flows of oil and gas properties, including estimates of future production, future commodity prices inclusive of market differentials, future operating and development costs, and the discount rate applied to the future cash flows.

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 proved oil and gas property impairment process, including controls related to the key assumptions. We compared forecasted commodity prices to publicly available market information and recalculated the relevant market differentials based on actual price realizations. We evaluated the Company's undiscounted future cash flows by comparing the Company's estimates of future production and future operating and development costs to historical results. We evaluated (1) the professional qualifications of the Company's internal reserve engineers as well as the external reserve engineers and external engineering firm, (2) the knowledge, skills, and ability of the Company's internal and external reserve engineers, and (3) the relationship of the external reserve engineers and external engineering firm to the Company. We involved valuation professionals with specialized skills and knowledge, who assisted in evaluating the Company's discount rate. This included comparing the Company's discount rate against a discount rate range that was developed using publicly available market data and against guideline ranges by reserve class from published industry surveys.

Emergence-date fair value of proved oil and gas properties

As discussed in Notes 1, 3 and 5 to the consolidated financial statements, the Company applied fresh start accounting upon emerging from Chapter 11 bankruptcy. Under the principles of fresh start accounting, the Company assigned the reorganization value to individual assets and liabilities based on their estimated fair values. The emergence-date fair value of the Company's property, plant and equipment was $2,682 million, of which $2,409 million related to its proved oil and gas properties. The Company estimated the fair value of its oil and gas properties using an income approach based on assumptions of future production, commodity prices inclusive of market differentials, operating and development costs, and a discount rate. 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 the emergence-date fair value of proved oil and gas properties as a critical audit matter due to the judgment inherent in estimating the future cash flows. Specifically, complex auditor judgment was required to evaluate key assumptions used to estimate the future cash flows of oil and gas properties, including estimates of future production, future commodity prices inclusive of market differentials, future operating and development costs, and the discount rate applied to the future cash flows.

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 proved oil and gas properties process, including controls related to the key assumptions. We compared the Company's estimates of future production and future operating and development costs to historical results. We compared future commodity prices to publicly available market information and recalculated the relevant market differentials based on actual price realizations. We evaluated (1) the professional qualifications of the Company's internal reserve engineers as well as the external valuation advisor and valuation firm, (2) the knowledge, skills, and ability of the Company's internal reserve engineers and external valuation advisor, and (3) the relationship of the external valuation advisor and external valuation firm to the Company. We involved valuation professionals with specialized skills and knowledge, who assisted in: (1) evaluating the future commodity prices used by the Company by comparing the benchmark prices utilized to publicly disclosed projected commodity prices; (2) comparing the Company's discount rate against a discount rate range that was developed using publicly available market data and against guideline ranges by reserve class from published industry surveys; and (3) comparing the overall fair value of the Company's oil and gas properties to publicly available market data, including recent sales transactions of similar assets.

/s/ KPMG LLP

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

Los Angeles, California
March 11, 2021

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets
As of December 31, 2020 (Successor) and 2019 (Predecessor)
(in millions, except share data)

	Successor 2020	Predecessor 2019
CURRENT ASSETS		
Cash	$ 28	$ 17
Trade receivables	177	277
Inventories	61	67
Other current assets, net	63	130
Total current assets	329	491
PROPERTY, PLANT AND EQUIPMENT	2,689	22,889
Accumulated depreciation, depletion and amortization	(34)	(16,537)
Total property, plant and equipment, net	2,655	6,352
OTHER ASSETS	90	115
TOTAL ASSETS	$ 3,074	$ 6,958
CURRENT LIABILITIES		
Current maturities of long-term debt	—	100
Accounts payable	212	296
Accrued liabilities	261	313
Total current liabilities	473	709
LONG-TERM DEBT, NET	597	5,023
OTHER LONG-TERM LIABILITIES	822	720
MEZZANINE EQUITY		
Redeemable noncontrolling interests	—	802
EQUITY		
Predecessor preferred stock (20 million shares authorized at $0.01 par value); no shares outstanding at December 31, 2019	—	—
Predecessor common stock (200 million shares authorized at $0.01 par value); 49,175,843 shares outstanding at December 31, 2019	—	—
Successor preferred stock (20 million shares authorized at $0.01 par value); no shares outstanding at December 31, 2020	—	—
Successor common stock (200 million shares authorized at $0.01 par value); 83,319,660 shares outstanding at December 31, 2020	1	—
Additional paid-in capital	1,268	5,004
Accumulated deficit	(123)	(5,370)
Accumulated other comprehensive loss	(8)	(23)
Total equity (deficiency) attributable to common stock	1,138	(389)
Noncontrolling interests	44	93
Total shareholders’ equity (deficiency)	1,182	(296)
TOTAL LIABILITIES AND EQUITY	$ 3,074	$ 6,958

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations
For the periods from November 1, 2020 through December 31, 2020, January 1, 2020 through October 31, 2020 and the years ended December 31, 2019 and 2018
(in millions, except per share data)

	Successor	Predecessor		
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Years ended December 31, 2019	Years ended December 31, 2018
REVENUES				
Oil and natural gas sales	$ 237	$ 1,092	$ 2,270	$ 2,590
Net derivative (loss) gain from commodity contracts	(141)	91	(59)	1
Trading revenue	38	124	286	330
Electricity sales	15	86	112	111
Other revenue	3	14	25	32
Total revenues	152	1,407	2,634	3,064
COSTS				
Operating costs	114	511	895	912
General and administrative expenses	40	212	290	299
Depreciation, depletion and amortization	34	328	471	502
Asset impairments	—	1,736	—	—
Taxes other than on income	10	134	157	149
Exploration expense	1	10	29	34
Trading costs	24	78	201	250
Electricity cost of sales	10	53	68	61
Transportation costs	8	35	40	36
Other expenses, net	17	89	54	52
Total costs	258	3,186	2,205	2,295
OPERATING (LOSS) INCOME	(106)	(1,779)	429	769
NON-OPERATING (LOSS) INCOME				
Reorganization items, net	(3)	4,060	—	—
Interest and debt expense, net	(11)	(206)	(383)	(379)
Net gain on early extinguishment of debt	—	5	126	57
Gain on asset divestitures	—	—	—	5
Other non-operating expenses	(5)	(84)	(72)	(23)
(LOSS) INCOME BEFORE INCOME TAXES	(125)	1,996	100	429
Income tax provision	—	—	(1)	—
NET (LOSS) INCOME	(125)	1,996	99	429
NET LOSS (INCOME) ATTRIBUTABLE TO NONCONTROLLING INTERESTS				
Mezzanine equity	—	(94)	(117)	(99)
Equity	2	(13)	(10)	(2)
Net loss (income) attributable to noncontrolling interests	2	(107)	(127)	(101)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	$ (123)	$ 1,889	$ (28)	$ 328
Net (loss) income attributable to common stock per share				
Basic	$ (1.48)	$ 40.59	$ (0.57)	$ 6.77
Diluted	$ (1.48)	$ 40.42	$ (0.57)	$ 6.77

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Comprehensive Income
For the periods from November 1, 2020 through December 31, 2020, January 1, 2020 through October 31, 2020 and the years ended December 31, 2019 and 2018
(in millions)

	Successor	Predecessor	Predecessor	
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Years ended December	
			2019	2018
Net (loss) income	$ (125)	$ 1,996	$ 99	$ 429
Less: Net loss (income) attributable to noncontrolling interests	2	(107)	(127)	(101)
Other comprehensive (loss) income items:				
Actuarial (losses) gains associated with pension and postretirement plans[(a)]	(8)	(2)	(24)	13
Reclassification of realized losses on pension and postretirement to income[(a)]	—	2	7	4
Total other comprehensive (loss) income	(8)	—	(17)	17
Comprehensive (loss) income attributable to common stock	$ (131)	$ 1,889	$ (45)	$ 345

(a) No associated tax has been recorded for the components of other comprehensive (loss) income for 2020, 2019 or 2018. See *Note 17 Pension and Postretirement Benefit Plans* for additional information on the components of other comprehensive income related to our defined benefit plans.

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Equity
For the years ended December 31, 2020, 2019 and 2018
(in millions)

	Common 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, December 31, 2017 (Predecessor)	$ —	$ 4,879	$ (5,670)	$ (23)	$ (814)	$ 94	$ (720)
Net income	—	—	328	—	328	2	330
Contribution from noncontrolling interest holders, net	—	—	—	—	—	82	82
Distributions paid to noncontrolling interest holders	—	—	—	—	—	(64)	(64)
Issuance of common stock in connection with the acquisition of Elk Hills unit	—	101	—	—	101	—	101
Other comprehensive income	—	—	—	17	17	—	17
Share-based compensation, net	—	7	—	—	7	—	7
Balance, December 31, 2018 (Predecessor)	$ —	$ 4,987	$ (5,342)	$ (6)	$ (361)	$ 114	$ (247)
Net income	—	—	(28)	—	(28)	10	(18)
Contribution from noncontrolling interest holders, net	—	—	—	—	—	49	49
Distributions paid to noncontrolling interest holders	—	—	—	—	—	(80)	(80)
Other comprehensive income	—	—	—	(17)	(17)	—	(17)
Warrant	—	3			3		3
Share-based compensation, net	—	14	—	—	14	—	14
Balance, December 31, 2019 (Predecessor)	$ —	$ 5,004	$ (5,370)	$ (23)	$ (389)	$ 93	$ (296)
Net income	—	—	1,889	—	1,889	13	1,902
Distributions paid 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

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

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 (Predecessor)	$ 1	$ 1,268	$ —	$ —	$ 1,269	$ 76	$ 1,345

	Common 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 (Successor)	$ 1	$ 1,268	$ —	$ —	$ 1,269	$ 76	$ 1,345
Net loss	—	—	(123)	—	(123)	(2)	(125)
Distributions paid to noncontrolling interest holders	—	—	—	—	—	(30)	(30)
Other comprehensive loss	—	—	—	(8)	(8)	—	(8)
Balance, December 31, 2020 (Successor)	$ 1	$ 1,268	$ (123)	$ (8)	$ 1,138	$ 44	$ 1,182

Note: Excludes amounts related to redeemable noncontrolling interests recorded in mezzanine equity. See *Note 7 Joint Ventures* 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 periods from November 1, 2020 through October 31, 2020, January 1, 2020 through October 31, 2020 and the years ended December 31, 2019 and 2018
(in millions)

	Successor	Predecessor		
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Years ended December 31, 2019	Years ended December 31, 2018
CASH FLOW FROM OPERATING ACTIVITIES				
Net (loss) income	$ (125)	$ 1,996	$ 99	$ 429
Adjustments to reconcile net (loss) income to net cash provided by operating activities:				
Depreciation, depletion and amortization	34	328	471	502
Asset impairment	—	1,736	—	—
Net derivative loss (gain) from commodity contracts	141	(91)	59	(1)
Net (payments) proceeds on settled commodity derivatives	(1)	108	111	(228)
Net gain on early extinguishment of debt	—	(5)	(126)	(57)
Amortization of deferred gain	—	(39)	(70)	(76)
Gain on asset divestitures	—	—	—	(5)
Other non-cash charges to income, net	27	60	131	97
Reorganization items, net (non-cash)	—	(4,128)	—	—
Reorganization items, net (debtor-in-possession financing costs)	—	25	—	—
Dry hole expenses	—	—	7	16
Changes in operating assets and liabilities, net:				
(Increase) decrease in trade receivables	(28)	128	22	(23)
Decrease (increase) in inventories	1	(1)	—	(6)
Decrease (increase) in other current assets	6	2	(1)	(9)
Decrease in accounts payable and accrued liabilities	(67)	(1)	(27)	(178)
Net cash (used) provided by operating activities	(12)	118	676	461
CASH FLOW FROM INVESTING ACTIVITIES				
Capital investments	(7)	(40)	(455)	(690)
Changes in capital investment accruals	(1)	(24)	(85)	69
Asset divestitures	—	41	164	18
Acquisitions	—	—	(6)	(547)
Other	1	(7)	(12)	(6)
Net cash used in investing activities	(7)	(30)	(394)	(1,156)
CASH FLOW FROM FINANCING ACTIVITIES				
Proceeds from 2014 Revolving Credit Facility	—	797	2,330	2,823
Repayments of 2014 Revolving Credit Facility	—	(1,315)	(2,353)	(2,646)
Proceeds from debtor-in-possession facilities	—	802	—	—
Repayments of debtor-in-possession facilities	—	(802)	—	—
Proceeds from Revolving Credit Facility	82	225	—	—
Repayments of Revolving Credit Facility	(208)	—	—	—
Proceeds from Second Lien Term Loan	—	200	—	—
Debtor-in-possession financing costs	—	(25)	—	—

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

Debt repurchases	—	(3)	(156)	(199)
Debt issuance costs	—	(20)	(2)	(4)
Payoff of the 2020 Senior Notes	—	(100)	—	—
Contributions from noncontrolling interest holders, net	—	—	49	796
Distributions to noncontrolling interest holders	(30)	(104)	(151)	(121)
Acquisition of noncontrolling interest in connection with the Plan	—	(2)	—	—
Issuance of common stock	—	446	4	54
Shares cancelled for taxes	—	(1)	(3)	(11)
Net cash (used) provided by financing activities	(156)	98	(282)	692
(Decrease) increase in cash	(175)	186	—	(3)
Cash—beginning of period	203	17	17	20
Cash—end of period	$ 28	$ 203	$ 17	$ 17

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. As discussed in *Note 2 Chapter 11 Proceedings*, we emerged from Chapter 11 proceedings on October 27, 2020. In connection with our emergence, our board of directors was reconstituted.

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.

Certain prior year amounts have been reclassified to conform to the current year presentation. We reclassified deferred gain and issuance costs, net to be presented within the long-term debt line on the face of our consolidated balance sheets.

Our consolidated financial statements, including the notes thereto, have been prepared assuming we will continue as a going concern. In preparing these consolidated financial statements accounting guidance requires that the financial statements distinguish transactions and events that are directly related to our bankruptcy filing and reorganization from the ongoing operations of the business. As a result, we have classified all income, expenses, gains or losses that were incurred or realized subsequent to the petition date of our bankruptcy filing as reorganization items, net on our consolidated statement of operations. During bankruptcy, we segregated our liabilities and obligations whose treatment and satisfaction were dependent on the outcome of the Chapter 11 Cases, which were limited to our long-term debt and related accrued interest up to the petition date as “liabilities subject to compromise” on our consolidated balance sheet. Upon emergence, these allowed claims were settled in exchange for new CRC common stock, subscription rights and warrants as discussed in *Note 2 Chapter 11 Proceedings.*

We qualified for and adopted fresh start accounting upon emergence from Chapter 11 at which point we became a new entity for financial reporting purposes 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. 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 2 Chapter 11 Proceedings* and *Note 3 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.

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 Successor period, three California refineries each accounted for at least 10%, and collectively accounted for 50%, of our oil and natural gas sales. For the 2020 Predecessor period and for the year ended December 31, 2019, two California refineries, each accounted for at least 10%, and collectively accounted for 46%, of our oil and natural gas sales. For the year ended December 31, 2018, two California refineries each accounted for at least 10%, and collectively accounted for 43%, of our oil and natural gas sales.

Critical Accounting Policies

Fresh Start Accounting and Allocation of Reorganization Value

We allocated the reorganization value under fresh start accounting to our identifiable assets and liabilities based on their estimated fair value. Our reorganization value was less than the 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 3 Fresh Start Accounting*.

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 given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. 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, 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. Other non-producing property and equipment is depreciated using the straight-line method based on expected initial lives of the individual assets or group of assets of up to 20 years.

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 property, plant and equipment (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 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.

Significant Accounting Policies

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.

See *Note 18 Revenue Recognition* where we present disaggregated revenues by commodity type.

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, 2020 was not material and losses associated with counterparty credit risk have been insignificant for all periods presented.

Inventories

Materials and supplies 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:

	Successor	Predecessor
(in millions)	2020	2019
Materials and supplies	$ 58	$ 64
Finished goods	3	3
Total	$ 61	$ 67

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

All of the pre-emergence outstanding stock-based awards under our then long-term incentive plan were cancelled upon emergence. As of December 31, 2020, no awards were issued under our new long-term incentive plan. The shares issuable under the new long-term incentive plan had been authorized by the bankruptcy court and the terms of the 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 9.3 million shares of common stock for future issuances, subject to adjustment.

Earnings Per Share

Basic earnings (loss) per share for all periods presented equals net income (loss) divided by the weighted average number of our shares outstanding during the period including participating securities. Diluted earnings (loss) per share is computed by dividing net income (loss) by the weighted average number of our shares outstanding including participating securities. Potentially dilutive securities for the Predecessor periods included warrants, stock options, restricted shares and performance units, when applicable. Potentially dilutive securities for the Successor periods included warrants. We compute basic and diluted earnings per share (EPS) using the two-class method required for participating securities, when applicable. 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 the 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 record an adjustment to both the ARO and PP&E. Over time, the liability is increased and expense is recognized for accretion, and the capitalized cost is recovered over either the useful life of our facilities or the unit-of-production method for our minerals. As part of fresh start accounting, the ARO liability was adjusted to the estimated fair value as described in *Note 3 Fresh Start Accounting*.

At certain of our facilities, we have identified ARO that are related mainly to plant and field decommissioning, including plugging and abandonment of wells. In certain cases, we do not know or cannot estimate when we would perform the ARO work and, therefore, we cannot reasonably estimate the fair value of these liabilities. 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.

	Successor	Predecessor	Predecessor
(in millions)	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	December 31, 2019
Beginning balance	$ 593	$ 517	$ 433
Liabilities incurred, capitalized to PP&E	—	—	(5)
Liabilities settled and paid	(5)	(12)	(26)
Accretion expense	8	33	36
Dispositions, reduction to PP&E	—	(4)	(10)
Other	1	2	4
Revisions in estimated cash flows	—	—	85
Impact of fresh start accounting	—	57	—
Ending balance	$ 597	$ 593	$ 517
Current portion	$ 50	$ 50	$ 28
Non-current portion	$ 547	$ 543	$ 489

Idle well regulations enacted in the first quarter of 2019 require operators to either (1) submit annual idle well management plans describing how they will plug and abandon or reactivate a specified percentage of long-term idle wells or (2) pay additional annual fees and perform additional testing every six years to retain greater flexibility to return long-term idle wells to service in the future. These regulations provide a six-year implementation period for testing existing idle wells not scheduled for plugging and abandonment. Newly idle wells must be tested within two years after becoming idle and, thereafter, are subject to the same testing schedule for existing idle wells.

Other 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 bases. 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 PSC-type contracts represented approximately 18% of our production for both the Successor and Predecessor periods in 2020.

In line with industry practice for reporting PSC-type contracts, 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 PSC-type contracts. 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.

As part of fresh start accounting, we measured our pension and postretirement medical plan assets and liabilities at fair value as described in *Note 3 Fresh Start Accounting.* Actuarial gains and losses that had not yet been recognized in the Predecessor period through income, which were recorded in accumulated other comprehensive income within equity, were eliminated as part of fresh start accounting. In the Successor period, we recorded actuarial gains and losses, net of taxes, in accumulated other comprehensive income until they are amortized as a component of net periodic benefit cost.

Cash

As of December 31, 2020, our cash on hand was $28 million, which was unrestricted. Cash at December 31, 2019 included approximately $3 million that was restricted under one of our joint venture (JV) agreements and approximately $14 million was unrestricted.

Other Current Assets

Other current assets, net consisted of the following:

(in millions)	Successor December 31, 2020	Predecessor December 31, 2019
Amounts due from joint interest partners, net[a]	$ 42	$ 70
Derivative assets	—	39
Prepaid expenses	20	19
Other	1	2
Other current assets, net	$ 63	$ 130

(a) As of December 31, 2020, we had no allowance for credit losses as a result of the adoption of fresh start accounting. Included in the balance as of December 31, 2019 was a $19 million allowance for credit losses against amounts due from joint interest partners.

Accrued Liabilities

Accrued liabilities consisted of the following:

(in millions)	Successor December 31, 2020	Predecessor December 31, 2019
Accrued employee-related costs	$ 72	$ 116
Accrued taxes other than on income	36	57
Asset retirement obligations	50	28
Accrued interest	1	13
Lease liability	7	28
Fair value of derivatives	50	—
Payments due to counterparties on commodity contracts	21	5
Other	24	66
Accrued liabilities	$ 261	$ 313

As of December 31, 2020, accrued employee-related costs included approximately $5 million of payroll taxes deferred under COVID-19 relief, half of which was due on or before December 31, 2021 with the remainder due on or before December 31, 2022.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

(in millions)	Successor December 31, 2020	Predecessor December 31, 2019
Asset retirement obligations	$ 547	$ 489
Deferred compensation and postretirement	184	182
Lease liability	35	38
Fair value of derivatives	6	—
Payments due to counterparties on commodity contracts	31	—
Other	19	11
Other long-term liabilities	$ 822	$ 720

Reorganization Items, net

Reorganization items, net consisted of the following (in millions):

(in millions)	Successor November 1, 2020 - December 31, 2020	Predecessor January 1, 2020 - October 31, 2020
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	(3)	(43)
Debtor-in-possession financing costs	—	(25)
Total reorganization items, net	**$ (3)**	**$ 4,060**

Supplemental Cash Flow Information

Supplemental disclosures to our consolidated statements of cash flows, excluding leases, are presented below (in millions):

	Successor	Predecessor		
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2019	Year ended December 31, 2018
Supplemental Cash Flow Information				
Cash paid for interest, net of amounts capitalized	$ (8)	$ (79)	$ (425)	$ (433)
Supplementary 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)		
Warrant issued to a joint venture partner			$ (3)	
Common stock issued as part of the acquisition of Elk Hills unit				$ (51)

NOTE 2 CHAPTER 11 PROCEEDINGS

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). The Chapter 11 Cases were jointly administered under the caption *In re California Resources Corporation, et al.*, Case No. 20-33568 (DRJ). We filed with the Bankruptcy Court, on July 24, 2020, the *Debtors' Joint Plan of Reorganization under Chapter 11 of the Bankruptcy Code* and, on October 8, 2020, the *Amended Debtors' Joint Plan of Reorganization Under Chapter 11 of the Bankruptcy Code* (as amended, supplemented or modified, the Plan). On October 13, 2020, the Bankruptcy Court confirmed the Plan, which was conditioned on certain items such as obtaining exit financing. The conditions to effectiveness of the Plan were satisfied and we emerged from Chapter 11 on October 27, 2020 (Effective Date). See *Note 3 Fresh Start Accounting* regarding the use of an accounting convenience date for the date of our emergence.

During the course of the Chapter 11 Cases, the Bankruptcy Court granted the relief requested in certain motions, authorizing payments of pre-petition liabilities with respect to certain employee compensation and benefits, taxes, royalties, certain essential vendor payments and insurance and surety obligations, which allowed our business operations to continue uninterrupted during the pendency of the Chapter 11 Cases. Payments for transactions outside the ordinary course of business required the prior approval of the Bankruptcy Court.

Missed Interest Payments and Forbearance

On May 15, 2020, we did not make an interest payment of approximately $4 million on our 2024 Notes. The indenture governing the 2024 Notes provided for a 30-day grace period and the payment was made on June 12, 2020.

On May 29, 2020, we did not pay approximately $51 million in the aggregate of interest due under our 2017 Credit Agreement and 2016 Credit Agreement. Our failure to make those interest payments constituted events of default under the 2017 Credit Agreement, 2016 Credit Agreement and, as a result of cross default, under the 2014 Revolving Credit Facility.

On June 2, 2020, we entered into forbearance agreements (Forbearance Agreements) with (i) certain lenders of a majority of the outstanding principal amount of the loans under the 2014 Revolving Credit Facility, (ii) certain lenders of a majority of the outstanding principal amount of the loans under the 2016 Credit Agreement, and (iii) certain lenders of a majority of the outstanding principal amount of the loans under the 2017 Credit Agreement. Pursuant to the Forbearance Agreements, the lenders who were parties to the Forbearance Agreements agreed to forbear from exercising any remedies under the 2014 Revolving Credit Facility, 2016 Credit Agreement and 2017 Credit Agreement with respect to our failure to make the aforementioned interest payments, initially through June 14, 2020 and subsequently through July 15, 2020.

On June 15, 2020, we did not make an interest payment of approximately $72 million on our Second Lien Notes. The indenture governing the Second Lien Notes provides for a 30-day grace period, which expired on July 15, 2020. We did not make the July 15, 2020 interest payment and commenced bankruptcy proceedings.

Commencement of Bankruptcy Proceedings

The commencement of a voluntary proceeding in bankruptcy constituted an immediate event of default under the 2014 Revolving Credit Facility, 2016 Credit Agreement, 2017 Credit Agreement, and the indentures governing the Second Lien Notes, 2021 Notes and 2024 Notes, resulting 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 the 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.

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 8 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 below and (ii) $450 million from the Subscription Rights Offering discussed below.

Ares JV Settlement Agreement

On July 15, 2020, immediately prior to the commencement of the Chapter 11 Cases, we and certain affiliates of Ares Management L.P. (Ares), including ECR Corporate Holdings L.P., a portfolio company of Ares (ECR), entered into a Settlement and Assumption Agreement (Settlement Agreement) related to our midstream joint venture, Elk Hills Power, LLC (Ares JV or Elk Hills Power), which held our Elk Hills power plant and a cryogenic gas processing plant. On August 25, 2020, the Bankruptcy Court entered an order approving the Settlement Agreement on a final basis. Among other things, the Settlement Agreement included a conversion right, which was deemed exercised 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 secured notes (EHP Notes; see *Note 8 Debt* for additional information), approximately 20.8% of our new common stock (Ares Settlement Stock) and approximately $2 million in cash. For more information on the Settlement Agreement, see *Note 7 Joint Ventures.*

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. 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, 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 below and reserved 9.3 million shares for future issuance under our management incentive plan, as described below:

- 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 (see *Note 8 Debt* and *Note 7 Joint Ventures* for additional information);
- 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.

The holders of Unsecured Debt Claims (as defined in the Plan) under the 2016 Credit Agreement, Second Lien Notes, 2021 Notes and 2024 Notes received Tier 1 Warrants and Tier 2 Warrants (each as defined in the Plan and collectively, Warrants) to purchase up to 2% and 3%, respectively, of our outstanding shares (on a fully diluted basis calculated immediately after the Effective Date), with an initial exercise price of $36 per share, which expire on October 27, 2024 and have customary anti-dilution protections (refer to *Note 15 Equity* for additional information on the Warrants).

On January 18, 2021, our Board of Directors approved the California Resources Corporation 2021 Long Term Incentive Plan (2021 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 bankruptcy and the terms of the new long-term incentive plan were approved by our Board. As a result, the 2021 Incentive Plan became effective on January 18, 2021. The 2021 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. In January 2021, we granted approximately 258,000 restricted stock units to our non-employee directors as the equity portion of their compensation. In addition, certain of our executives were granted approximately 544,000 restricted stock units and approximately 544,000 performance stock units.

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 8 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. Our new Board is led by Mark A. (Mac) McFarland, our Chairman and interim Chief Executive Officer, and James N. Chapman, our Lead Independent Director.

Restructuring Charge

We reduced our workforce in August 2020 in response to economic conditions. In addition, our former Chief Financial Officer (CFO) departed on August 14, 2020 and former Chief Executive Officer (CEO) on December 31, 2020. In connection with these events, we recorded a charge to other expenses, net of $10 million in the Predecessor period and $5 million in the Successor period for post employment costs which primarily consisted of notice and severance pay. As of December 31, 2020, our remaining liability of $7 million was included in accrued liabilities. During 2019, we implemented operational efficiencies and an organizational redesign that included a reduction in our workforce. We recorded a related charge of $41 million, consisting of $29 million in notice and severance pay and $12 million in other termination benefits. As of December 31, 2019, our remaining liability of $19 million was included in accrued liabilities.

NOTE 3 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 right of use (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. Our existing well population is approximately 18,000 individual well bores, on gross basis, and 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 PSC-type contracts.

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

	Predecessor	Reorganization Adjustments		Fresh Start Adjustments		Successor
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 2 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 8 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
5.5% Senior Notes due 2021		100
6% Senior Notes due 2024		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, Ares Settlement 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. See *Note 9 Leases* for more information on our leases.

(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 4 ACCOUNTING AND DISCLOSURE CHANGES

Recently Adopted Accounting and Disclosure Changes

We adopted new accounting guidance on current expected credit losses on January 1, 2020, using a modified retrospective approach to the first period in which the guidance was effective. The new rules changed the measurement of credit losses for financial assets and certain other instruments, including trade and other receivables with a right to receive cash, and require the use of a new forward-looking expected loss model that results in the earlier recognition of an allowance for losses. The adoption of these new rules did not have a significant impact on our consolidated financial statements.

We adopted the Financial Accounting Standards Board’s new lease accounting rules (ASC 842), as of January 1, 2019, using the modified retrospective approach where the new lease standard is not applied to prior comparative periods, which continue to be presented under accounting standards in effect for those prior periods. The adoption of the new lease accounting rules did not materially impact our consolidated results of operations and had no impact on cash flows or beginning retained earnings.

NOTE 5 PROPERTY, PLANT AND EQUIPMENT

In connection with the application of fresh start accounting, as discussed in *Note 3 Fresh Start Accounting*, we recorded our PP&E at fair value as of our emergence date. Predecessor accumulated depreciation, depletion and amortization was therefore eliminated as of that date.

We capitalize the costs incurred to acquire or develop our oil and natural gas assets, including ARO and capitalized 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. We recorded a $1.7 billion impairment charge in the first quarter of 2020 for our proved and unproved oil and natural gas properties.

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

	Successor	Predecessor
(in millions)	December 31, 2020	December 31, 2019
Proved oil and natural gas properties	$ 2,416	$ 21,285
Unproved oil and natural gas properties[a]	1	1,055
Facilities and other	272	549
Total property, plant and equipment	2,689	22,889
Accumulated depreciation, depletion and amortization	(34)	(16,537)
Total property, plant and equipment, net	$ 2,655	$ 6,352

(a) Includes a valuation allowance for unproved properties of zero and $823 million at December 31, 2020 and 2019, respectively.

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

	Successor	Predecessor		
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Years ended December 31,	
(in millions)			2019	2018
Beginning balance	$ 3	$ 7	$ 5	$ 4
Additions to capitalized exploratory well costs	—	—	12	19
Reclassification to property, plant and equipment	—	—	(3)	(2)
Charged to expense	—	(2)	(7)	(16)
Impact of fresh start accounting	—	(2)	—	—
Ending balance	$ 3	$ 3	$ 7	$ 5

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. In response to the commodity price environment, in the first quarter of 2020, we suspended our drilling program which continued throughout the remainder of 2020. Our capitalized exploratory well costs at December 31, 2020 are for permitted wells that we intend to drill.

See *Note 13 Asset Impairment* for more information on our first quarter impairment charge and *Note 3 Fresh Start Accounting* for more information on fair value adjustments.

NOTE 6 DIVESTITURES AND ACQUISITIONS

Divestitures

Lost Hills Divestiture

In May 2019, we sold 50% of our working interest and transferred operatorship in certain zones within our Lost Hills field, located in the San Joaquin basin, for total consideration in excess of $200 million, consisting of approximately $168 million in cash and a carried 200-well development program to be drilled through 2023 with an estimated value of $35 million (Lost Hills divestiture). We received cash proceeds of $164 million after transaction costs and purchase price adjustments, which were used to pay down our 2014 Revolving Credit Facility. The partial sale of proved property was accounted for as a normal retirement with no gain or loss recognized. The partial sale of unproved property was recorded as a recovery of cost.

Other

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. In 2018, we divested non-core assets resulting in $18 million of proceeds and recognized a $5 million gain.

Acquisitions

Elk Hills Transaction

In April 2018, we acquired the remaining working, surface and mineral interests in the approximately 47,000-acre Elk Hills unit from Chevron U.S.A., Inc. (Chevron) (the Elk Hills transaction) for approximately $518 million, including $7 million of liabilities assumed relating to ARO. We accounted for the Elk Hills transaction as a business combination. As of December 31, 2019, we held all of the working, surface and mineral interests in the former Elk Hills unit. The effective date of the transaction was April 1, 2018.

As part of the Elk Hills transaction, Chevron reduced its royalty interest in one of our oil and natural gas properties by half and extended the time frame to invest the remainder of our capital commitment on that property by the end of 2022. As of December 31, 2020, the remaining commitment was approximately $12 million. In addition, the parties mutually agreed to release each other from pending claims with respect to the former Elk Hills unit.

Bakersfield Office Building

In April 2018, we also acquired an office building and land in Bakersfield, California for $48 million.

Other

In 2019, we had several other acquisitions totaling approximately $6 million. In 2018, we had other upstream acquisitions totaling approximately $39 million, excluding assumed ARO liabilities of $1 million.

NOTE 7 JOINT VENTURES

Noncontrolling Interests

The following tables present the changes in noncontrolling interests for our consolidated JVs (described in greater detail below), which are reported in equity and mezzanine equity on our consolidated balance sheets:

	Equity Attributable to Noncontrolling Interests			Mezzanine Equity - Redeemable Noncontrolling Interest	
	Ares JV	BSP JV	Total	Ares JV	Total
			(in millions)		
Balance, December 31, 2018 (Predecessor)	$ 15	$ 99	$ 114	$ 756	$ 756
Net (loss) income attributable to noncontrolling interests	(7)	17	10	117	117
Contributions from noncontrolling interest holders, net	—	49	49	—	—
Distributions to noncontrolling interest holders	(8)	(72)	(80)	(71)	(71)
Balance, December 31, 2019 (Predecessor)	$ —	$ 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)
Impact of fresh start accounting	—	7	7	—	—
Balance, October 31, 2020 (Predecessor)	$ —	$ 76	$ 76	$ —	$ —

	Equity Attributable to Noncontrolling Interest
	BSP JV
	(in millions)
Balance, October 31, 2020 (Successor)	$ 76
Net (loss) income attributable to noncontrolling interests	(2)
Distributions to noncontrolling interest holders	(30)
Balance, December 31, 2020 (Successor)	$ 44

Ares JV

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 (Elk Hills Power), and each of CREH and ECR held an equity interest in this entity.

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. As required by the Note Purchase Agreement, CREH transferred its ownership of two low temperature separation plants located at the Elk Hills field to Elk Hills Power.

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. As contemplated by the terms of the JV, CREH purchased electricity and gas processing services from the Ares JV (subject to certain limitations, including certain geographical limitations) in exchange for monthly capacity payments pursuant to the terms of a Commercial Agreement, the proceeds of which were used by the Ares JV to make distributions as contemplated by the Second Amended and Restated Limited Liability Company Agreement of Elk Hills Power, LLC. CREH also served as the operator of the Ares JV and provided operational and support services in exchange for a monthly fee pursuant to a Master Services Agreement. These agreements became intercompany agreements on the Effective Date and were cancelled as described below.

As described in *Note 2 Chapter 11 Proceedings*, we entered into the 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, Ares Settlement Stock and approximately $2 million in cash. The Conversion Right was exercised on the Effective Date.

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 16 Earnings per Share* for adjustments to net income (loss) attributable to common stock 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, Ares Settlement Stock comprising approximately 20.8% (subject to dilution) of common stock 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.

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 already 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.

Our consolidated statements of operations for the Predecessor periods 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 reduce the carrying amount of noncontrolling interests on our consolidated balance sheets and are reported as a financing cash outflow on our consolidated statements of cash flows. ECR's redeemable noncontrolling interests was reported in mezzanine equity due to an embedded optional redemption feature.

BSP JV

In February 2017, we entered into a development joint venture with Benefit Street Partners (BSP) where BSP invested $200 million to date, before transaction costs, in exchange for a preferred interest in the BSP JV. BSP is entitled to preferential distributions and, if it receives cash distributions equal to a predetermined threshold, the preferred interest is automatically redeemed in full with no additional payment. The funds contributed by BSP were used to develop certain of our oil and natural gas properties.

The BSP JV holds net profits interests (NPI) in existing and future cash flow from certain of our properties and the proceeds from the NPI are used by the BSP JV to (1) pay quarterly minimum distributions to BSP, (2) make distributions to BSP until the predetermined threshold is achieved, and (3) pay for additional development costs within the project area, upon mutual agreement between members.

Our consolidated results reflect the operations of our development JV with BSP, with BSP's preferred interest reported in equity on our consolidated balance sheets and BSP's share of net income (loss) reported in net income attributable to noncontrolling interests in our consolidated statements of operations for all periods presented. Distributions to BSP reduce the carrying amount of noncontrolling interests on our consolidated balance sheets and are reported as a financing cash outflow on our consolidated statements of cash flows.

Other

Alpine JV

In July 2019, we entered into a development joint venture with Alpine Energy Capital, LLC (Alpine) to develop portions of our Elk Hills field (Alpine JV). Alpine is a joint venture between subsidiaries of Colony Capital, Inc. (Colony) and Equity Group Investments. Alpine committed to invest an initial $320 million in the Elk Hills field of which $226 million has been invested to date. The initial commitment was expected to be invested over a period of up to three years in accordance with a 275-well development plan. Alpine will fund 100% of the drilling and completion costs of these wells, in which they will earn a 90% working interest. If Alpine receives an agreed upon return, our working interest in those wells will increase from 10% to 82.5%. Our consolidated financial statements reflect only our working interest share in the productive wells.

On March 27, 2020, Alpine elected to suspend its funding obligations pursuant to a contractual right that was triggered when the average NYMEX 12-month forward strip price for Brent crude oil fell below $45 per barrel over a 30-trading day period. The suspension may be lifted by mutual consent. As of December 31, 2020, funding for the initial development phase has not re-started.

In connection with the Alpine JV, we issued a warrant to purchase up to 1.25 million shares of our Predecessor common stock at an exercise price of $40 per share. On the Effective Date, this warrant was cancelled, pursuant to the Plan.

MIRA JV

In April 2017, we entered into a development joint venture with Macquarie Infrastructure and Real Assets Inc. (MIRA) to develop certain of our oil and natural gas properties in the San Joaquin basin in exchange for a 90% working interest in the related properties (MIRA JV). MIRA funded 100% of the drilling and completion costs of wells in the agreed-upon drilling program. Our 10% working interest increases to 75% if MIRA receives cash distributions equal to a predetermined threshold return. The initial phase of the agreed-upon drilling program was funded through December 31, 2020. Our consolidated results reflect only our working interest share in the productive wells.

Royale JV

In October 2018, we entered into a three-year development joint venture for a 30-well program with Royale Energy, Inc. (Royale) where Royale committed approximately $23 million for natural gas development in Sacramento Valley, of which $8 million has been funded to date. We committed to investing approximately $13 million, of which $4 million has been funded to date. In June 2020, we entered into an amendment with Royale which postponed the start dates of the second- and third-year drilling programs by one year. Our consolidated results reflect our 40% working interest share of production from these wells.

NOTE 8 DEBT

In January 2021, we completed a private placement of $600 million in senior unsecured notes due 2026 (Senior Notes). The net proceeds of $590 million were used to repay in full our Second Lien Term Loan and EHP Notes, with the remainder used to repay a portion of the outstanding borrowings under our Revolving Credit Facility. The Senior Notes will be guaranteed on a senior unsecured basis by certain of our material subsidiaries. See *Note 19 Subsequent Events* for additional information on this offering.

Post-Emergence Indebtedness

As of December 31, 2020, our long-term debt consisted of the following credit agreements, Second Lien Notes and Senior Notes (in millions):

	Successor		Interest Rate[a]	Maturity
	2020			
Credit Agreements				
Revolving Credit Facility	$	99	LIBOR plus 3%-4% ABR plus 2%-3%	April 29, 2024
Second Lien Notes				
Second Lien Term Loan		200	LIBOR plus 9%-10.5% ABR plus 8%-9.5%	October 27, 2025
Senior Notes				
EHP Notes		300	6%	October 27, 2027
Long-term debt (principal amount)	$	599		
Unamortized debt issuance costs		(2)		
Total long-term debt, net	$	597		

(a) London Interbank Offered Rates (LIBOR) will be phased out after 2021 and replaced with the Secured Overnight Financing Rate within the United States for U.S. dollar-based LIBOR. Our credit agreements contemplate a discontinuation of LIBOR and have an alternate borrowing rate. We do not expect the discontinuation of LIBOR to have a significant impact on our interest expense.

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 currently consists of a $540 million senior revolving loan facility (Revolving Credit Facility), which we are permitted to increase if we obtain additional commitments from new or existing lenders. The aggregate revolving commitment is subject to an automatic reduction if additional commitments from new lenders are not obtained. As a result, we expect the aggregate commitment of our lenders will be reduced to $492 million in April 2021. Our Revolving Credit Facility also includes a sub-limit of $200 million for the issuance of letters of credit. As of December 31, 2020, we had approximately $307 million available for borrowing under the Revolving Credit Facility after taking into account $134 million of outstanding letters of credit.

On the Effective Date, we borrowed $225 million under the Revolving Credit Facility to refinance our DIP Facilities, replace our existing letters of credit and pay certain costs, fees and expenses related to the other transactions consummated on the Effective Date. Our initial borrowings included $118 million used to cash collateralize on an interim basis certain letters of credit that were outstanding under our Senior DIP Facility. These letters of credit were transitioned into our new Revolving Credit Facility at December 31, 2020. 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, except assets securing the EHP Notes as discussed below.

Interest Rate – We can elect to borrow at either an adjusted LIBOR rate or an ABR rate, 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 adjusted LIBOR rate plus 1%. The applicable margin is adjusted based on the borrowing base utilization percentage and will vary from (i) in the case of LIBOR loans, 3% to 4% and (ii) in the case of ABR loans, 2% to 3%; provided that in the event that the EHP Notes are not paid in full on or prior to December 31, 2021, the applicable margin will be increased by 0.25% effective as of January 1, 2022 and will be increased by an additional 0.25% at the beginning of each subsequent fiscal quarter until such date on which the EHP Notes are paid in full. 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 LIBOR loans is payable at the end of each LIBOR period, but not less than quarterly.

Maturity Date – Our Revolving Credit Facility matures on April 29, 2024.

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 secured 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.

Our Revolving Credit Facility also requires us to maintain hedges on a minimum amount of crude oil production, determined semi-annually, of no less than (i) 75% of our reasonably anticipated oil production from our proved reserves for the first 24 months after the closing of the Revolving Credit Facility, which occurred on the Effective Date, and (ii) 50% of our reasonably anticipated oil production from our proved reserves for a period from the 25th month through the 36th month after the same date. The Revolving Credit Facility specifies the forms of hedges and prices (which can be prevailing prices) that must be used for a portion of those hedges.

We must also maintain acceptable commodity hedges for no less than 50% of the reasonably anticipated oil production from our proved reserves for at least 24 months following the date of delivery of each reserve report. We may not hedge more than 80% of reasonably anticipated total forecasted production of crude oil, natural gas and natural gas liquids from our oil and gas properties for a 48-month period.

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.

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 in *Note 19 Subsequent Events*.

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 in *Note 19 Subsequent Events*.

Pre-Emergence Indebtedness

2014 Revolving Credit Facility

In September 2014, we entered into a Credit Agreement with JPMorgan Chase Bank, N.A, as administrative agent, and certain other lenders. This credit agreement consisted of a $1 billion senior revolving loan facility (2014 Revolving Credit Facility), which we were permitted to increase by up to $50 million if we obtain additional commitments from new or existing lenders and also included a sub-limit of $400 million for the issuance of letters of credit. Prior to our Chapter 11 Cases in 2020, we amended our the 2014 Revolving Credit Facility to reduce our credit facility to $900 million and our borrowing base was reduced to $1.2 billion.

Amounts outstanding under the 2014 Revolving Credit Facility bore interest at either LIBOR or an alternate base rate (ABR), in each case plus an applicable margin. The applicable margin was adjusted based on the borrowing base utilization percentage under the 2014 Revolving Credit Facility and could vary from (i) in the case of LIBOR loans, 3.25% to 4.00% and (ii) in the case of ABR loans, 2.25% to 3.00%. The unused portion of the facility is subject to a commitment fee of 0.50% per annum. We also paid customary fees and expenses.

The lenders shared a first-priority lien on a substantial majority of our assets with the lenders under of 2017 Credit Agreement, excluding the Elk Hills power plant and midstream assets that are part of the Ares JV. The maturity date of our 2014 Revolving Credit Facility was June 30, 2021.

Under the 2014 Revolving Credit Facility, we were subject to various financial covenants including a monthly liquidity requirement and quarterly tests including maximum leverage ratio, minimum interest coverage ratio and minimum asset coverage ratio. Our 2014 Revolving Credit Facility also 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 from paying cash dividends on our stock.

The 2014 Revolving Credit Facility was terminated and repaid with proceeds from the Senior DIP Facility and Junior DIP Facility.

2017 Credit Agreement

In November 2017, we entered into a $1.3 billion credit agreement with The Bank of New York Mellon Trust Company, N.A., as administrative agent, and certain other lenders (2017 Credit Agreement). Our 2017 Credit Agreement is secured by the same shared first-priority lien used to secure our 2014 Revolving Credit Facility. The maturity date of the loans was December 31, 2022, subject to a springing maturity of 91 days prior to the maturity of our 2016 Credit Agreement if more than $100 million is outstanding at that time.

We were required to maintain a first-lien asset coverage ratio of not less than 1.20 to 1.00 as of any June 30 and December 31. In addition, our 2017 Credit Agreement provided for customary covenants and events of default consistent with, or generally less restrictive than, the covenants in our 2014 Revolving Credit Facility. The covenants included limitations on additional indebtedness, liens, asset dispositions and investments, among others, and were in each case subject to certain limitations and exceptions. We were also restricted from paying cash dividends on our stock.

The 2017 Credit Agreement was cancelled upon our emergence from bankruptcy as described in *Note 2 Chapter 11 Proceedings*.

2016 Credit Agreement

In August 2016, we entered into a $1 billion credit agreement with The Bank of New York Mellon Trust Company, N.A., as administrative agent, and certain other lenders (2016 Credit Agreement). Our 2016 Credit Agreement was secured by a first-priority lien on a substantial majority of our assets (excluding the Elk Hills power plant and midstream assets that are part of the Ares JV) but was second in collateral recovery to our 2014 Revolving Credit Facility and 2017 Credit Agreement. The maturity date of the 2016 Credit Agreement was December 31, 2021.

We were required to maintain a first–lien asset coverage ratio of not less than 1.20 to 1.00 as of any June 30 and December 31. Our 2016 Credit Agreement also included other covenants that are substantially similar to our 2017 Credit Agreement. We were also restricted from paying cash dividends on our stock.

The 2016 Credit Agreement was cancelled upon our emergence from bankruptcy as described in *Note 2 Chapter 11 Proceedings*.

Second Lien Notes

In December 2015, we issued $2.25 billion in aggregate principal amount of 8% senior secured second-lien notes due December 15, 2022 (Second Lien Notes). The Second Lien Notes were issued in exchange for $2.8 billion of our then outstanding Senior Notes. We recorded a deferred gain of approximately $560 million on the debt exchange, which was being amortized using the effective yield method over the term of our Second Lien Notes.

Our Second Lien Notes were secured on a junior-priority basis to the first-priority liens that secure the loans under our 2014 Revolving Credit Facility, 2017 Credit Agreement and 2016 Credit Agreement. The indenture included covenants that, among other things, limited our ability to grant liens securing borrowed money (subject to certain exceptions) and restricted our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity.

In the first quarter of 2020, we repurchased $7 million in face value of our Second Lien Notes for $3 million in cash, resulting in a pre-tax gain of $5 million including the effect of unamortized deferred gain and issuance costs. In 2019, we repurchased $252 million in face value of our Second Lien Notes for $156 million in cash, resulting in a pre-tax gain of $126 million including the effect of unamortized deferred gain and issuance costs.

The Second Lien Notes were cancelled upon our emergence from bankruptcy as described in *Note 2 Chapter 11 Proceedings*.

Senior Notes

In October 2014, we issued $5 billion in aggregate principal amount of our senior unsecured notes, including $1 billion of 5% notes due January 15, 2020 (2020 Notes), $1.75 billion of 5.5% notes due September 15, 2021 (2021 Notes) and $2.25 billion of 6% notes due November 15, 2024 (2024 Notes and, collectively, Senior Notes). We used the net proceeds from the issuance of our Senior Notes to make a $4.95 billion cash distribution to Occidental in October 2014.

The indenture included covenants that, among other things, limited our ability to grant liens securing borrowed money subject to certain exceptions and restrict our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity.

The Senior Notes were cancelled upon our emergence from bankruptcy as described in *Note 2 Chapter 11 Proceedings*.

Other

At December 31, 2020, all obligations under our Revolving Credit Facility and Second Lien Term Loan 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, 2020, we were in compliance with all debt covenants under our credit agreements.

Principal maturities of debt outstanding at December 31, 2020 (Successor) are as follows:

	As of December 31, 2020
	(in millions)
2021	$ —
2022	—
2023	—
2024	99
2025	200
Thereafter	300
Total	$ 599

We estimate the fair value of fixed-rate debt, which is classified as Level 3, based on unobservable inputs as of December 31, 2020. We estimate the fair value of fixed-rate debt, which is classified as Level 1, based on prices known from market transactions as of December 31, 2019. The estimated fair value of our debt at December 31, 2020 and 2019, including the fair value of the variable-rate portion, was approximately $599 million and $3.8 billion, respectively, compared to a face value of approximately $599 million and $5.0 billion, respectively.

NOTE 9 LEASES

We lease commercial office space, fleet vehicles, drilling rigs and facilities. We do not recognize acquired leases or leases with an initial term of 12 months or less on the balance sheet. Upon adoption of fresh start accounting, our right of use (ROU) assets and lease liabilities were recorded at the present value of the remaining fixed minimum lease payments as if the leases were new leases upon our emergence date. The effect of fresh start accounting on leases was not material. Refer to *Note 3 Fresh Start Accounting* for more details.

Balance sheet information related to our operating and finance leases as of December 31, 2020 and December 31, 2019 were as follows:

	Classification	Successor 2020	Predecessor 2019
		(in millions)	(in millions)
Assets			
Operating	*Other assets*	$ 38	$ 59
Finance	*PP&E*	1	2
Total leased assets		$ 39	$ 61
Liabilities			
Current			
Operating	*Accrued liabilities*	$ 6	$ 27
Finance	*Accrued liabilities*	1	1
Long-term			
Operating	*Other long-term liabilities*	35	37
Finance	*Other long-term liabilities*	—	1
Total lease liabilities		$ 42	$ 66

In considering whether a contract contains a lease, we first considered whether there was an identifiable asset and then considered how and for what purpose the asset would be used over the contract term. Our lease liability was determined by measuring the present value of the remaining fixed minimum lease payments discounted using our incremental borrowing rate (IBR). In determining our IBR, we considered the average cost of borrowing for publicly traded corporate bond yields, which were adjusted to reflect our credit rating, the remaining lease term for each class of our leases and frequency of payments.

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 renew, which we exercise at our sole discretion, and we did not include these options in determining our fixed minimum lease payments over the lease term. Our lease liability does not include options to extend or terminate our leases. 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 included 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, were as follows:

	Successor	Predecessor	
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	January 1, 2019 - December 31, 2019
	(in millions)	(in millions)	
Operating lease costs	$ 2	$ 23	$ 52
Short-term lease costs[(a)]	7	25	74
Variable lease costs[(b)]	—	4	21
Total operating lease costs	9	52	147
Finance lease costs	—	$ 1	$ —
Sublease income	$ —	$ (1)	$ (1)
Total lease costs	$ 9	$ 52	$ 146

(a) Contracts with terms of less than one month or less are excluded from our disclosure of short-term lease costs.
(b) No variable lease costs related to drilling rigs in the Successor period. The Predecessor period of January 1, 2020 through October 31, 2020 includes $3 million related to drilling rigs and 2019 includes $19 million, which were capitalized to PP&E.

We have two contracts treated as finance leases, which were not material to our consolidated results of operations.

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. 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, 2020 and December 31, 2019 is provided below:

	Successor	Predecessor	
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	January 1, 2019 - December 31, 2019
	(in millions)	(in millions)	
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash outflows from operating leases	$ 2	$ 9	$ 14
Investing cash outflows from operating leases	$ —	$ 14	$ 40
Financing cash outflows from finance leases	$ —	$ 1	$ —
ROU assets obtained in exchange for new operating lease liabilities	$ —	$ —	$ 122
ROU assets obtained in exchange for new finance lease liabilities	$ —	$ —	$ 2
Impairment charges related to ROU assets	$ —	$ 2	$ 3

	Successor	Predecessor
	2020	2019
Operating Leases		
Weighted-average remaining lease term (in years)	6.81	4.75
Weighted-average discount rate	4.5%	12.2%
Finance Leases		
Weighted-average remaining lease term (in years)	1.33	2.33
Weighted-average discount rate	4.0%	8.5%

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

As part of our company-wide consolidation of office space, we vacated certain office space in 2020 and 2019, some of which we subleased. When we enter into a sublease agreement, we evaluate the carrying value of our ROU asset (including the carrying value of related tenant improvements) for impairment based on future identifiable cash flows. We may terminate leases for vacated office space before the expiration of the lease term. In cases where we decided not to sublease vacated commercial office space, we shorten the useful life of the ROU assets and related tenant improvements to recover our remaining costs over our expected period of use.

Maturities of our operating and finance lease liabilities at December 31, 2020 are as follows:

	Successor	
	Operating Leases	Finance Leases
	(in millions)	
2021	$ 8	$ 1
2022	8	—
2023	7	—
2024	6	—
2025	5	—
Thereafter	15	—
Less: Interest	(7)	—
Present value of lease liabilities	$ 42	$ 1

NOTE 10 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, 2020 and 2019 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 determined that former lessees, including our former parent, Occidental Petroleum Corporation (Oxy) with an approximately 35% share, are responsible for accrued decommissioning obligations associated with these offshore platforms. Oxy notified us of the claim under the indemnification provisions of the Separation and Distribution Agreement between us and Oxy. We are currently evaluating this claim.

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.

We have certain commitments under contracts, including purchase commitments for goods and services used in the normal course of business such as pipeline capacity, land easements and field equipment. At December 31, 2020, total purchase obligations on a discounted basis were as follows:

	December 31, 2020
	(in millions)
2021	$ 42
2022	50
2023	35
2024	6
2025	6
Thereafter	47
Total	186
Less: Interest	(28)
Present value of purchase obligations	$ 158

We remain subject to audit by the Internal Revenue Service for calendar years 2017 through 2019 as well as 2016 through 2019 by the state of California.

NOTE 11 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. Our Revolving Credit Facility and Second Lien Term Loan require that we hedge a significant amount of crude oil production as described in *Note 8 Debt*. We have met our hedging obligation under our Revolving Credit Facility and Second Lien Term Loan.

Commodity-Price Risk

We did not have any commodity derivatives designated as accounting hedges as of and during the years ended December 31, 2020, 2019 and 2018. As part of our hedging program, we held the following Brent-based crude oil contracts as of December 31, 2020:

	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022	January - October 2023
Sold Calls:						
Barrels per day	19,028	33,372	35,202	10,645	30,783	17,758
Weighted-average price per barrel	$ 47.88	$ 48.64	$ 49.83	$ 56.00	$ 59.37	$ 58.01
Purchased Puts						
Barrels per day	39,148	37,872	36,617	35,483	30,783	17,758
Weighted-average price per barrel	$ 41.88	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00
Sold Puts						
Barrels per day	15,659	15,149	14,647	14,193	3,042	—
Weighted-average price per barrel	$ 35.97	$ 31.41	$ 30.00	$ 32.00	$ 32.00	$ —
Swaps						
Barrels per day	7,830	7,574	7,323	7,097	6,576	5,919
Weighted-average price per barrel	$ 43.74	$ 44.13	$ 43.82	$ 45.30	$ 46.29	$ 47.57

The BSP JV holds crude oil derivatives and natural gas swaps for insignificant volumes through 2021 that are included in our consolidated results. The hedges entered into by the BSP JV could affect the timing of the redemption of BSP's preferred interest.

The outcomes of the derivative positions are as follows:

- Sold call options – we make settlement payments for prices above the indicated weighted-average price per barrel.
- Purchased put options – we receive settlement payments for prices below the indicated weighted-average price per barrel.
- Sold put options – we make 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.

From time to time, we may use combinations of these positions to increase the efficacy of our hedging program.

We mark our derivative contracts to market at the end of each reporting period. These noncash derivative gains and losses, along with settlement payments, are reported in net derivative (loss) gain from commodity contracts on our consolidated statements of operations as shown in the table below:

	Successor	Predecessor		
(in millions)	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2019	Year ended December 31, 2018
Non-cash derivative (loss) gain	$ (140)	$ (17)	$ (170)	$ 229
Net (payments) proceeds on settled commodity derivatives	(1)	108	111	(228)
Net derivative (loss) gain from commodity contracts	$ (141)	$ 91	$ (59)	$ 1

Interest-Rate Risk

In May 2018, we entered into derivative contracts that limit our interest rate exposure with respect to $1.3 billion of our variable-rate indebtedness. These interest-rate contracts reset monthly and require the counterparties to pay any excess interest owed on such amount in the event the one-month LIBOR exceeds 2.75% for any monthly period prior to May 4, 2021.

For the Successor and Predecessor periods in 2020, we did not report gains or losses on these contracts. For the year ended December 31, 2019, we reported a loss on these contracts, included in other non-operating expenses on our consolidated statement of operations, of $4 million. No payments from these contracts were received in either 2020 or 2019.

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.

Commodity Contracts

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

December 31, 2020 (Successor)			
Classification	**Gross Amounts at Fair Value**	**Netting**	**Net Fair Value**
		(in millions)	
Assets:			
Other current assets	$ 21	$ (21)	$ —
Other assets	63	(63)	—
Liabilities:			
Accrued liabilities	(71)	21	(50)
Other long-term liabilities	(69)	63	(6)
	$ (56)	$ —	$ (56)

December 31, 2019 (Predecessor)			
Classification	**Gross Amounts at Fair Value**	**Netting**	**Net Fair Value**
		(in millions)	
Assets:			
Other current assets	$ 49	$ (10)	$ 39
Other assets	1	—	1
Liabilities:			
Accrued liabilities	(15)	10	(5)
Other long-term liabilities	—	—	—
	$ 35	$ —	$ 35

Interest-Rate Contracts

The fair value of our interest-rate derivatives contracts was not significant for all periods presented.

Counterparty Credit Risk

As of December 31, 2020, all of our derivative financial instruments were with investment-grade counterparties. We believe exposure to credit-related losses at December 31, 2020 was not material and losses associated with credit risk have been insignificant for all years presented.

All of our derivative instruments are covered by International Swap Dealers Association Master Agreements with counterparties. At December 31, 2020, and 2019, we had insignificant collateral posted.

NOTE 12 INCOME TAXES

Income Tax Provision (Benefit)

Net (loss) income before income taxes, for all periods presented, was generated from domestic operations. We did not record a significant income tax provision (benefit) in any of the periods presented, due to our valuation allowance.

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

	Successor	Predecessor		
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Years ended December 31,	
			2019	2018
U.S. federal statutory tax rate	(21)%	21%	21%	21%
State income taxes, net	(7)	7	7	6
Exclusion of income attributable to noncontrolling interests, net	—	(1)	(35)	(5)
Debt restructuring, net	—	(8)	—	—
Changes in tax attributes, net	—	7	(9)	(6)
Nondeductible compensation, net	—	—	3	—
Change in valuation allowance, net	27	(27)	14	(17)
Other, net	1	1	—	1
Effective tax rate	— %	— %	1 %	— %

Our effective tax rate is primarily affected by state taxes, income included in our consolidated results which is taxed to noncontrolling interests, and the benefit of tax credits, when available. Further, as a result of our emergence from bankruptcy, we wrote-off deferred tax assets because of the limitation on the realizability of our net operating loss and tax carryforwards as described further below. Given our income tax position, any item affecting our effective tax rate is generally offset by an equal change in the valuation allowance.

In connection with our emergence from bankruptcy and cancellation of claims, which were included in liabilities subject to compromise as of our emergence date, we generated cancellation of debt income for tax purposes which was excluded from taxable income under rules related to bankruptcy proceedings. In exchange for this exclusion, for federal purposes, we were required to reduce our net operating loss (NOL) and tax credit carryforwards and the tax basis of our assets, primarily property, plant and equipment. The primary driver of the income tax benefit related to the cancellation of our debt is due to the mechanics of attribute reduction for state combined income tax reporting purposes.

Our ability to utilize our remaining NOL, tax credit and interest expense carryforwards may be limited since we experienced an “ownership change” in connection with the restructuring process. Absent an applicable exception, if a corporation undergoes an ownership change, the amount of its NOLs and other carryforwards that may be used to reduce U.S. federal and state income tax obligations is subject to an annual limitation. Although an exception to the imposition of an annual limitation applies in Chapter 11 Cases under Section 382(l)(5) of the Internal Revenue Code of 1986, as amended, it is currently not likely if we will apply such section because if we experience a subsequent ownership change within two years of the Effective Date, any remaining net operating losses and certain other tax attributes, including interest expense carryforwards, may be subject to further and more severe limitations. Accordingly, the write-off of the benefit for our remaining NOLs and other carryforwards had the effect of increasing our effective tax rate in the Predecessor period.

Deferred Tax Assets and Liabilities

The tax effects of temporary differences resulting in deferred income tax assets and liabilities at December 31, 2020 and 2019 were as follows:

	Successor		Predecessor	
	2020		2019	
(in millions)	Deferred Tax Assets	Deferred Tax Liabilities	Deferred Tax Assets	Deferred Tax Liabilities
Debt	$ 3	$ —	$ 176	$ —
Property, plant and equipment	209	(113)	—	(517)
Postretirement benefit accruals	43	—	40	—
Deferred compensation and benefits	23	—	55	—
Asset retirement obligations	178	—	155	—
Net operating loss and tax credit carryforwards	12	—	457	—
Business interest expense carryforward	180	—	194	—
Investment in partnerships	—	—	110	—
Other	34	(20)	36	(60)
Subtotal	682	(133)	1,223	(577)
Valuation allowance	(549)	—	(646)	—
Total deferred taxes	$ 133	$ (133)	$ 577	$ (577)

Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit use of existing deferred tax assets. A significant piece of evidence evaluated is a history of operating losses. Such evidence limits our ability to consider other evidence such as projections for growth. As of December 31, 2020, we concluded that we could not realize, on a more-likely-than-not basis, any of our deferred tax assets and there is not sufficient evidence to support the reversal of all or any portion of this allowance. Given our recent and anticipated future earnings trends, we do not believe any significant amount of the valuation allowance as of December 31, 2020 will be released within the next 12 months. Changes in assumptions could materially affect the recognized amounts of valuation allowance.

Other

As of December 31, 2020, we had U.S. federal net operating loss carryforwards of $17 million, which begin to expire in 2039. Our carryforward for business interest expense of $855 million does not expire.

As of December 31, 2020, we had California net operating loss carryforwards of approximately $2 billion, which begin to expire in 2026, and an insignificant amount of tax credit carryforwards.

Unrecognized Tax Benefits

We did not record a liability for unrecognized tax benefits in the Successor period. The following is a reconciliation of unrecognized tax benefits in the Predecessor period:

	Predecessor		
	January 1, 2020 - October 31, 2020	Years ended December 31,	
(in millions)		2019	2018
Unrecognized tax benefits – beginning balance	$ 101	$ 25	$ 25
Gross (decreases) increases – tax positions in prior year	(101)	44	—
Gross increases – tax positions in current year	—	32	—
Unrecognized tax benefits – ending balance	$ —	$ 101	$ 25

On July 28, 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 at least on a more-likely-than-not basis and accordingly we reversed a $76 million liability for uncertain tax positions. Further, we re-evaluated a tax return filing position taken in prior periods and reversed a $25 million liability for uncertain tax positions.

NOTE 13 ASSET IMPAIRMENT

At March 31, 2020, we recorded a $1.7 billion impairment charge which was triggered by the sharp drop in commodity prices at the end of the first quarter of 2020 due to the significant decrease in demand for oil and natural gas products as a result of the Coronavirus Disease 2019 (COVID-19) pandemic coupled with the over-supply resulting from a price war between members of the Organization of the Petroleum Exporting Countries (OPEC) and Russia and other allied producing countries. The following table presents a summary of our asset impairments as of our March 31, 2020 assessment date (in millions):

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

Proved oil and natural gas properties — The fair values of our proved oil and natural gas properties were determined as of the date of the assessment 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 primarily related to a steamflood property located in the San Joaquin basin.

Unproved properties — As of our 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.

NOTE 14 STOCK-BASED COMPENSATION

As a result of our bankruptcy, the outstanding stock-based awards under our Amended and Restated California Resources Corporation Long-Term Incentive Plan (Amended LTIP) were cancelled on our Effective Date.

On January 18, 2021, our Board of Directors approved the California Resources Corporation 2021 Long Term Incentive Plan (2021 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 2021 Incentive Plan became effective on January 18, 2021. The 2021 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 2021 Incentive Plan provides for the reservation of 9,257,740 shares of common stock for future issuances, subject to adjustment as provided in the 2021 Incentive Plan. Shares of stock subject to an award under the 2021 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 2021 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 2021 Incentive Plan.

In January 2021 we granted approximately 258,000 restricted stock units to our non-employee directors as the equity portion of their compensation. In addition, certain of our executives were granted approximately 544,000 restricted stock units and 544,000 performance stock units.

Predecessor Compensation Plan

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 7.3 million shares. As of December 31, 2019, 4.7 million shares were issued or reserved under the Amended LTIP and 2.6 million shares were available for future issuance of awards. In the second quarter of 2020, our then Board of Directors approved the following changes to the 2020 compensation program: (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.

As shown in the table below, we recognized the following stock-based compensation expense during the Predecessor periods. No stock-based compensation was recognized during the Successor period.

	Predecessor		
	January 1, 2020 - October 31, 2020	Years ended December 31,	
(in millions)		2019	2018
Stock-based compensation expense	$ 3	$ 32	$ 45
Payments of cash-based portion of awards	$ 8	$ 25	$ 24

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. 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.

The following summarizes our RSU activity for 2020:

	Stock-Settled		Cash-Settled
	Number of Units	Weighted-Average Grant-Date Fair Value	Number of Units
	(in thousands)		(in thousands)
Unvested at December 31, 2019 (Predecessor)	554	$ 17.54	2,285
Granted	633	$ 6.20	4,327
Vested	(357)	$ 16.40	(1,062)
Cancelled or Forfeited	(830)	$ 9.37	(5,550)
Unvested at October 31, 2020 (Predecessor)	—	$ —	—

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. All outstanding PSUs were cancelled for no consideration as a result of our emergence from bankruptcy.

The following summarizes our PSU activity for 2020:

	Stock-Settled		Cash-Settled
	Number of Awards	Weighted-Average Grant-Date Fair Value	Number of Units
	(in thousands)		(in thousands)
Unvested at December 31, 2019 (Predecessor)	497	$ 19.75	401
Granted	792	$ 6.20	792
Cancelled or Forfeited	(1,289)	$ 11.43	(1,193)
Unvested at October 31, 2020 (Predecessor)	—	$ —	—

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. All outstanding stock options were cancelled for no consideration as a result of our emergence from bankruptcy.

The following table summarizes our option activity during 2020:

	Options (in thousands)	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Aggregate Intrinsic Value
Balance at December 31, 2019 (Predecessor)	1,427	$ 59.00	$ 16.81	$ —
Granted	593	$ 6.82	$ 3.31	$ —
Cancelled or Forfeited	(2,020)	$ 43.68	$ 12.84	$ —
Balance at October 31, 2020 (Predecessor)	—	$ —	$ —	$ —

NOTE 15 EQUITY

On the Effective Date, all our Predecessor common and preferred stock, including contracts on our equity were cancelled pursuant to the Plan and 83.3 million shares of new common stock were issued. See *Note 2 Chapter 11 Proceedings* for further information.

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

	Common Stock (in thousands)
Balance, December 31, 2018 (Predecessor)	48,650
Issued	694
Cancelled	(168)
Balance, December 31, 2019 (Predecessor)	49,176
Issued	451
Predecessor shares cancelled	(49,627)
Balance, October 31, 2020 (Predecessor)	—
Share Issuance	83,321
Balance, October 31, 2020 (Successor)	83,321
Share Issuance	—
Balance, December 31, 2020 (Successor)	83,321

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 shares were issued under the plan after March 31, 2020.

Warrants

On the Effective Date, we issued Warrants for an aggregate 4.4 million shares of Successor common stock. The Warrants are exercisable for 5% of the outstanding shares of new common stock (on a fully diluted basis calculated immediately after the Effective Date) at an initial exercise price of $36 per share. The Warrants are exercisable from the Effective Date for a period of four years. The Warrant Agreement contains customary anti-dilution adjustments in the event of any stock split, reverse stock split, stock dividend, equity awards under the 2021 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.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) consisted of unrealized losses associated with our pension and postretirement benefit plans for all periods presented. 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. See *Note 3 Fresh Start Accounting* for additional information.

Unregistered Issuance of Equity Securities

Other than the shares issued in reliance of Section 4(a)(2) of the Securities Act as described below, we relied on Section 1145(a)(1) of the Bankruptcy Code as an exemption from the registration requirements of the Securities Act for the issuance of our new common stock and warrants. Section 1145(a)(1) of the Bankruptcy Code exempts the offer and sale of securities under a plan of reorganization from registration under Section 5 of the Securities Act and state laws if three principal requirements are satisfied:

- The securities must be issued under a plan of reorganization by the debtor, its successor under a plan, or an affiliate participating in a joint plan of reorganization with the debtor;
- The recipients of the securities must hold a claim against, an interest in, or a claim for administrative expense in the case concerning the debtor or such affiliate; and
- The securities must be issued either (a) in exchange for the recipient’s claim against, interest in or claim for administrative expense in the case concerning the debtor or such affiliate or (b) principally in such exchange and partly for cash or property.

The (a) shares of new common stock issued pursuant to the Backstop Commitment Agreement, (b) shares of new common stock issued in connection with the payment of the backstop commitment premium and the exit fee for the Junior DIP Facility, and (c) Ares Settlement Stock issued to Ares pursuant to the Settlement Agreement were issued in each case without registration in reliance upon the exemption set forth in Section 4(a)(2) of the Securities Act and are therefore “restricted securities.”

On the Effective Date, we entered into a registration rights agreement with the backstop parties under the Backstop Commitment Agreement and each holder of at least 1% of the new common stock outstanding on the Effective Date, granting such parties customary registration rights with respect to their new common stock.

NOTE 16 EARNINGS PER SHARE

We compute basic and diluted earnings per share (EPS) using the two-class method required for participating securities. Certain of our restricted and performance stock awards were considered participating securities because they had non-forfeitable dividend rights at the same rate as our Predecessor common stock.

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 outstanding shares related to unvested restricted stock awards. Weighted-average shares were calculated based on the number of days in the Predecessor and Successor periods. For diluted EPS, the basic shares outstanding are adjusted by adding all potentially dilutive securities.

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

(in millions, except per share amounts)	Successor	Predecessor		
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Years ended December 31, 2019	Years ended December 31, 2018
Basic EPS calculation				
Net income (loss)	$ (125)	$ 1,996	$ 99	$ 429
Less: Net income attributable to noncontrolling interests	2	(107)	(127)	(101)
Net (loss) income attributable to common stock	(123)	1,889	(28)	328
Less: Net income allocated to participating securities	—	(22)	—	(7)
Modification of noncontrolling interest[(a)]	—	138	—	—
Net (loss) income available to common stockholders	$ (123)	$ 2,005	$ (28)	$ 321
Weighted-average common shares outstanding	83.3	49.4	49.0	47.4
Basic EPS	$ (1.48)	$ 40.59	$ (0.57)	$ 6.77
Diluted EPS calculation				
Net income (loss)	$ (125)	$ 1,996	$ 99	$ 429
Less: Net income attributable to noncontrolling interests	2	(107)	(127)	(101)
Net (loss) income attributable to common stock	(123)	1,889	(28)	328
Less: Net income allocated to participating securities	—	(22)	—	(7)
Modification of noncontrolling interest[(a)]	—	138	—	—
Net (loss) income available to common stockholders	$ (123)	$ 2,005	$ (28)	$ 321
Weighted-average common shares outstanding - Basic	83.3	49.4	49.0	47.4
Dilutive effect of potentially dilutive securities	—	0.2	—	—
Weighted-average common shares outstanding - Diluted	83.3	49.6	49.0	47.4
Diluted EPS	$ (1.48)	$ 40.42	$ (0.57)	$ 6.77
Weighted-average antidilutive shares	4.4	4.0	3.1	1.6

(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 7 Joint Ventures*.

NOTE 17 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, 2020 and 2019, we recognized $35 million and $37 million in other long-term liabilities for these supplemental plans, respectively.

We expensed $4 million in the Successor period and $28 million in the Predecessor period during 2020, $36 million in 2019 and $35 million in 2018 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 2020, approximately 70 employees accrued benefits under these plans, all of whom were union employees. Effective December 31, 2015, the plans were amended such that participants other than union employees no longer earn benefits for service after December 31, 2015.

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 to the plan, but the benefits are primarily funded by us as claims are paid during the year.

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, as of December 31, 2020 and 2019 (in millions):

	Successor		Predecessor	
	2020		2019	
	Pension	Postretirement	Pension	Postretirement
Amounts recognized on the balance sheet				
Accrued liabilities	$ —	$ (4)	$ —	$ (3)
Other long-term liabilities	(15)	(125)	(18)	(113)
	$ (15)	$ (129)	$ (18)	$ (116)
Amounts recognized in accumulated other comprehensive loss	$ (1)	$ (7)	$ (6)	$ (17)

The following table shows the funding status of our pension and post-retirement benefit plans along with a reconciliation of our benefit obligations and fair value of plan asset as of December 31, 2020 and 2019 (in millions):

	Successor	Predecessor	
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	January 1, 2019 - December 31, 2019
Pension			
Changes in the benefit obligation			
Benefit obligation—beginning balance	$ 46	$ 45	$ 56
Service cost—benefits earned during the period	—	1	1
Interest cost on projected benefit obligation	—	1	2
Actuarial loss (gain)	3	1	11
Benefits paid	(2)	(2)	(25)
Benefit obligation—ending balance	$ 47	$ 46	$ 45
Changes in plan assets			
Fair value of plan assets—beginning balance	$ 26	$ 27	$ 42
Actual gain (loss) return on plan assets	2	1	7
Employer contributions	6	—	3
Benefits paid	(2)	(2)	(25)
Fair value of plan assets—ending balance	$ 32	$ 26	$ 27
Net benefit liability (unfunded status)	$ (15)	$ (20)	$ (18)
Postretirement			
Changes in the benefit obligation (in millions)			
Benefit obligation—beginning balance	$ 122	$ 116	$ 84
Service cost—benefits earned during the period	1	4	4
Interest cost on projected benefit obligation	—	3	4
Actuarial loss (gain)	7	2	19
Cost of special termination benefits	—	—	6
Curtailment	—	—	2
Benefits paid	(1)	(3)	(3)
Benefit obligation—ending balance	$ 129	$ 122	$ 116
Changes in plan assets			
Fair value of plan assets—beginning balance	$ —	$ —	$ —
Employer contributions	1	3	3
Benefits paid	(1)	(3)	(3)
Fair value of plan assets—ending balance	$ —	$ —	$ —
Net benefit liability (unfunded status)	$ (129)	$ (122)	$ (116)

Our accumulated benefit obligation for our defined benefit pension plans exceeded the fair value of our plan assets as shown in the table below for the years ended December 31:

	Successor	Predecessor
	2020	2019
(in millions)		
Projected benefit obligation	$ 47	$ 45
Accumulated benefit obligation	$ 43	$ 41
Fair value of plan assets	$ 32	$ 27

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 expenses 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		
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Years ended December 31,	
			2019	2018
Pension				
Net periodic benefit costs				
Service cost—benefits earned during the period	$ —	$ 1	$ 1	$ 1
Interest cost on projected benefit obligation	—	1	2	2
Expected return on plan assets	—	(1)	(2)	(3)
Amortization of net actuarial loss	—	1	1	2
Settlement costs	—	1	9	4
Net periodic benefit costs	$ —	$ 3	$ 11	$ 6
Postretirement				
Net periodic benefit costs				
Service cost—benefits earned during the period	$ 1	$ 4	$ 4	$ 4
Interest cost on projected benefit obligation	—	3	4	4
Expected return on plan assets	—	—	—	—
Cost of special termination benefits	—	—	6	—
Amortization of net actuarial loss	—	—	—	—
Settlement costs	—	1	—	—
Net periodic benefit costs	$ 1	$ 8	$ 14	$ 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 before tax (in millions):

	Successor	Predecessor		
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Years ended December 31,	
			2019	2018
Pension				
Net actuarial (loss) gain	$ (1)	$ (1)	$ (6)	$ (3)
Settlement costs	—	1	9	4
Amortization of net actuarial gain/ loss	—	1	1	2
Total recognized in other comprehensive (loss) income	$ (1)	$ 1	$ 4	$ 3
Postretirement				
Net actuarial (loss) gain	$ (7)	$ (2)	$ (19)	$ 14
Settlement costs	—	1	(2)	—
Amortization of net actuarial gain/ loss	—	—	—	—
Total recognized in other comprehensive (loss) income	$ (7)	$ (1)	$ (21)	$ 14

Settlement costs related to our pension and postretirement plans were associated with early retirements.

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

	Successor	Predecessor	
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	January 1, 2019 - December 31, 2019
Pension			
Benefit Obligation Assumptions			
Discount rate	2.42%	2.70%	3.16%
Rate of compensation increase	4.00%	4.00%	4.00%
Net Periodic Benefit Cost Assumptions			
Discount rate	2.70%	3.16%	4.22%
Assumed long-term rate of return on assets	5.42%	5.42%	6.50%
Rate of compensation increase	4.00%	4.00%	4.00%
Postretirement			
Benefit Obligation Assumptions			
Discount rate	2.92%	3.11%	3.48%
Net Periodic Benefit Cost Assumptions			
Discount rate	3.11%	3.48%	4.57%

For pension plans and postretirement benefit plans that we or our subsidiaries sponsor, we based the discount rate on the Aon AA Above Median yield curve in both 2020 and 2019. The weighted-average rate of increase in future compensation levels is consistent with our past and anticipated future compensation increases for employees participating in retirement 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 2020, we used the Society of Actuaries Pri-20212 mortality assumptions reflecting the MP-2020 scale which plan sponsors in the U.S. use in the actuarial valuations that determine a plan sponsor's pension and postretirement obligations. Changes in mortality assumptions were reflected in the valuations of our pension and postretirement benefit obligations as part of fresh start accounting upon emergence from bankruptcy. These assumptions did not significantly change our pension benefit obligations or postretirement benefit obligations in 2020 as compared to the prior year.

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 2.06% and 1.86% as of December 31, 2020 and 2019, 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, 2020, health care cost trend rates would decrease from 6.50%-7.00% in 2020 until they reach 4.50% in 2028 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 2020 and 2019, the target allocation of plan assets was 65% equity securities and 35% debt securities. 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.

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

	Fair Value Measurements at December 31, 2020 (Successor)			
	Level 1	**Level 2**	**Level 3**	**Total**
	(in millions)			
Asset Class				
Cash equivalents	$ 6	$ —	$ —	$ 6
Commingled funds				
Fixed income	—	2	—	2
U.S. equity	—	3	—	3
International equity	—	2	—	2
Mutual funds				
Bond funds	5	—	—	5
Blend funds	—	—	—	—
Value funds	2	—	—	2
Growth funds	6	—	—	6
Guaranteed deposit account	—	—	6	6
Total pension plan assets	$ 19	$ 7	$ 6	$ 32

	Fair Value Measurements at December 31, 2019 (Predecessor)			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Asset Class				
Cash equivalents	$ —	$ —	$ —	$ —
Commingled funds				
Fixed income	—	3	—	3
U.S. equity	—	4	—	4
International equity	—	2	—	2
Mutual funds				
Bond funds	5	—	—	5
Blend funds	2	—	—	2
Value funds	2	—	—	2
Growth funds	2	—	—	2
Guaranteed deposit account	—	—	7	7
Total pension plan assets	$ 11	$ 9	$ 7	$ 27

Expected Contributions and Benefit Payments

In 2021, we expect to contribute $5 million to our pension and $5 million to our postretirement benefit plans. 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)	
2021	$ 13	$ 5
2022	$ 2	$ 5
2023	$ 3	$ 5
2024	$ 2	$ 5
2025	$ 3	$ 5
2026 to 2030 Payouts	$ 11	$ 27

NOTE 18 REVENUE RECOGNITION

The following table provides disaggregated revenue from contracts with customers:

	Successor	Predecessor		
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Years ended December 31,	
(in millions)			2019	2018
Oil and natural gas sales				
Oil	$ 176	$ 874	$ 1,884	$ 2,110
NGLs	29	106	179	260
Natural gas	32	112	207	220
	237	1,092	2,270	2,590
Electricity sales	15	86	112	111
Trading revenue	38	124	286	330
Other revenue	3	14	25	32
	56	224	423	473
Net derivative (loss) gain from commodity contracts	(141)	91	(59)	1
Total revenues	$ 152	$ 1,407	$ 2,634	$ 3,064

Commodity Sales Contracts

We recognize revenue from the sale of our production when delivery has occurred and control passes to the customer. Our contracts with customers are short term, typically less than a year. We consider our performance obligations to be satisfied upon transfer of control of the commodity. In certain instances, transportation and processing fees are incurred by us prior to control being transferred to customers. We record these costs as a component of other expenses, net on our consolidated statements of operations.

Our commodity sales contracts are 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 invoicing.

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 to 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 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.

Trading Revenue and Other

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 consider our performance obligations to be satisfied upon transfer of control of the commodity.

We report our trading revenue in total revenues and associated purchases of commodities related to our trading activities are reported in other expenses, net on our consolidated statements of operations.

NOTE 19 SUBSEQUENT EVENTS

In January 2021, we completed an offering of $600 million of Senior Notes. The net proceeds of $590 million were used to repay in full our Second Lien Term Loan and EHP Notes, with the remainder used to repay a portion of the outstanding borrowings under our Revolving Credit Facility. The Senior Notes are general unsecured obligations which are guaranteed on a senior unsecured basis by certain of our material subsidiaries. We may redeem some or all of the Senior Notes at any time on or after February 1, 2023 at specified redemption prices. Prior to such time, we may redeem up to 35% of the aggregate principal amount of the Senior Notes using cash from certain equity offerings at specified redemption prices. If we experience certain change of control events, we will be required to offer to repurchase the Senior Notes at a premium. The indenture contains other customary terms, events of default and covenants.

Refer to *Note 14 Stock-Based Compensation* for the approval of our 2021 Incentive Plan and related issuances of awards.

Quarterly Financial Data (Unaudited)

Not applicable.

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 PSC-type contracts relating to our Wilmington field in Long Beach. 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, 2017	442	58	706	618
Revisions of previous estimates[(c)]	51	(4)	(15)	44
Improved recovery	4	—	—	4
Extensions and discoveries	25	1	27	30
Acquisitions	38	11	89	64
Production	(30)	(6)	(73)	(48)
Balance at December 31, 2018	530	60	734	712
Revisions of previous estimates[(c)]	(34)	(4)	(52)	(47)
Improved recovery	3	—	—	3
Extensions and discoveries	24	2	41	33
Divestitures	(11)	—	6	(10)
Production	(29)	(6)	(75)	(47)
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
PROVED DEVELOPED RESERVES				
December 31, 2017	304	45	543	440
December 31, 2018	389	47	565	530
December 31, 2019	357	45	543	493
December 31, 2020[(d)]	266	39	460	382
PROVED UNDEVELOPED RESERVES				
December 31, 2017	138	13	163	178
December 31, 2018	141	13	169	182
December 31, 2019	126	7	111	151
December 31, 2020	47	2	67	60

(a) Includes proved reserves related to economic arrangements similar to PSCs of 85 MMBbl, 125 MMBbl, 131 MMBbl and 108 MMBbl at December 31, 2020, 2019, 2018 and 2017, 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 Wilmington field in Long Beach 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 27% of proved developed oil reserves, 13% of proved developed NGLs reserves, 16% of proved developed natural gas reserves and, overall, 24% of total proved developed reserves at December 31, 2020 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.

2020

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.

2019

Revisions of previous estimates – We had negative price-related revisions of 20 MMBoe primarily resulting from a lower commodity-price environment in 2019 compared to 2018.

We had 16 MMBoe of net positive performance-related revisions. We added 23 MMBoe primarily related to better-than-expected performance in the San Joaquin and Los Angeles basins and 18 MMBoe that had been previously removed due to budgeting and development timing. These volumes were brought back into our reserves based on re-evaluation of the applicable areas and management's plans. These positive revisions were partially offset by 25 MMBoe in negative performance-related revisions primarily related to delayed responses in certain waterflood and steamflood projects.

We removed 43 MMBoe of proved undeveloped reserves, of which 19 MMBoe related to expired projects not developed within the five-year window as the result of lower-than-anticipated product prices. The remaining 24 MMBoe had not yet expired but were no longer prioritized in our development plans in the current commodity price environment. The majority of these proved undeveloped reserves that were downgraded at management's discretion are located in the San Joaquin basin, meet economic investment criteria at current prices and are anticipated to be developed in the future.

Extensions and discoveries – We added 33 MMBoe from extensions and discoveries, primarily resulting from successful drilling in the San Joaquin and Los Angeles basins.

Improved recovery – We also added 3 MMBoe from improved recovery through IOR and EOR methods, which were associated with the continued development of steamflood and waterflood properties in the San Joaquin basin.

Divestitures – We had a reduction of 10 MMBoe in connection with the Lost Hills divestiture and the Alpine JV entered into during the year. See *Part II, Item 7 Management's Discussion and Analysis, Acquisitions and Divestitures* for more on the Lost Hills divestiture and *Part II, Item 7 Management's Discussion and Analysis, Joint Ventures* for more on the Alpine JV.

2018

Revisions of previous estimates – Our 2018 realized prices for oil and natural gas increased over the prior year by 39% and 14%, respectively, which resulted in positive price-related revisions of 38 MMBoe. We also added 6 MMBoe from net positive performance-related revisions of which 27 MMBoe were from positive technical revisions primarily due to better-than-expected performance and successful drilling efforts in the San Joaquin and Los Angeles basins.

Additionally, at management's discretion, we removed a total of 21 MMBoe of proved undeveloped reserves that were not yet expired but that were not anticipated to be developed within their five-year window of initial booking. Approximately 11 MMBoe of these downgraded proved undeveloped reserves expired in 2019 and were not anticipated to be developed before then at current oil prices. The remaining 10 MMBoe of downgraded proved undeveloped reserves were projects that are no longer prioritized in our development plan based on current project economics.

Improved recovery – We also added 4 MMBoe from improved recovery through proven IOR and EOR methods. The improved recovery additions were associated with the continued development of steamflood and waterflood properties in the San Joaquin basin.

Extensions and discoveries – We added 30 MMBoe from extensions and discoveries, primarily resulting from new geologic interpretations and pressure data in the Ventura basin along with successful drilling in San Joaquin and Los Angeles basins.

Acquisitions – We also added 64 MMBoe in connection with the acquisitions during the year, the majority of which resulted from the Elk Hills transaction.

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	Predecessor
	December 31, 2020	December 31, 2019
	(in millions)	(in millions)
Proved properties	$ 2,416	$ 21,285
Unproved properties	1	1,055
Total capitalized costs[(a)]	2,417	22,340
Accumulated depreciation, depletion and amortization[(b)]	(31)	(16,300)
Net capitalized costs	$ 2,386	$ 6,040

(a) Includes acquisition and development costs.
(b) No valuation allowance was recorded for unproved properties at December 31, 2020. Balance at December 31, 2019 includes an accumulated valuation allowance for total unproved properties of $823 million.

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		
	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	For the years ended 2019	For the years ended 2018
	(in millions)	(in millions)		
Property acquisition costs				
Proved properties	$ —	$ —	$ 1	$ 553
Unproved properties	—	—	4	1
Exploration costs	1	10	30	38
Development costs[(a)]	7	35	505	652
Costs incurred	$ 8	$ 45	$ 540	$ 1,244

(a) There were no costs incurred for development costs related to ARO in 2020. Development costs include a $80 million increase and $7 million decrease in ARO in 2019 and 2018, respectively. Development costs in 2019 reflect an allocation related to a warrant issued in connection with the Alpine JV of $3 million.

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	
	November 1, 2020 - December 31, 2020		January 1, 2020 - October 31, 2020	
	(millions)	($/Boe)[a]	(millions)	($/Boe)[a]
Revenues[b]	$ 235	$ 37.49	$ 1,196	$ 34.98
Operating costs[c]	114	18.19	511	14.95
General and administrative expenses	7	1.12	38	1.11
Other operating expenses[d]	14	2.22	53	1.55
Depreciation, depletion and amortization	31	4.95	299	8.75
Taxes other than on income	4	0.64	106	3.10
Asset impairment	—	—	1,733	50.69
Exploration expenses	1	0.16	10	0.29
Pretax income	64	10.21	(1,554)	(45.46)
Income tax expense[e]	(18)	(2.87)	435	12.72
Results of operations	$ 46	$ 7.34	$ (1,119)	$ (32.74)

	For the years ended December 31,			
	2019		2018	
	(millions)	($/Boe)[a]	(millions)	($/Boe)[a]
Revenues[b]	$ 2,377	$ 50.88	$ 2,359	$ 48.84
Operating costs[c]	895	19.16	912	18.88
General and administrative expenses	56	1.20	49	1.01
Other operating expenses[d]	71	1.52	51	1.07
Depreciation, depletion and amortization	439	9.40	469	9.71
Taxes other than on income	121	2.59	117	2.42
Asset impairment	—	—	—	—
Exploration expenses	29	0.62	34	0.70
Pretax income	766	16.39	727	15.05
Income tax expense[e]	(205)	(4.39)	(180)	(3.85)
Results of operations	$ 561	$ 12.00	$ 547	$ 11.20

(a) 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.
(b) Revenues include cash settlements on our commodity derivatives which are reported in net derivative (gain) loss from commodity contracts on our consolidated statements of operations.
(c) 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. Operating costs on a per Boe basis, excluding the effects of PSC-type contracts, were $14.14 and 16.86 for the Successor and Predecessor periods of 2020, respectively. Operating costs on a per Boe basis, excluding the effects of PSC-type contracts, were $17.70 and $17.47 for the years 2019 and 2018, respectively.
(d) Other operating expenses primarily include accretion on our asset retirement obligations and transportation costs.
(e) 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 28%. The effective tax rate for 2018 reflects the benefit of enhanced oil recovery 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, 2020, 2019 and 2018, 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, 2020, 2019 and 2018. 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	Predecessor	
	December 31, 2020	December 31, 2019	December 31, 2018
(in millions)			
Future cash inflows	$ 15,532	$ 34,134	$ 42,325
Future costs			
Operating costs[(a)]	(9,389)	(16,724)	(19,452)
Development costs[(b)]	(2,392)	(3,938)	(4,432)
Future income tax expense	(701)	(3,180)	(4,231)
Future net cash flows	3,050	10,292	14,210
Ten percent discount factor	(1,118)	(5,061)	(6,935)
Standardized measure of discounted future net cash flows	$ 1,932	$ 5,231	$ 7,275

(a) Includes general and administrative expenses 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	Predecessor	
	2020	2019	2018
(in millions)			
Beginning of year	$ 5,231	$ 7,275	$ 3,765
Sales of oil and natural gas, net of production and other operating costs	(1,257)	(1,198)	(1,511)
Changes in price, net of production and other operating costs	(3,940)	(1,998)	3,648
Previously estimated development costs incurred	519	556	351
Change in estimated future development costs	1,032	(283)	(38)
Extensions, discoveries and improved recovery, net of costs	122	433	443
Revisions of previous quantity estimates[(a)]	(1,407)	(638)	738
Accretion of discount	650	890	427
Net change in income taxes	1,124	518	(1,356)
Purchases and sales of reserves in place	(25)	(151)	766
Changes in production rates and other	(117)	(173)	42
Net change	(3,299)	(2,044)	3,510
End of year	$ 1,932	$ 5,231	$ 7,275

(a) Includes revisions related to performance and price changes.

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, 2020 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, 2020, our system of internal control over financial reporting is effective.

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our interim 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 interim CEO and CFO have concluded that, as of December 31, 2020, 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 interim 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, 2020 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

None.

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 2021 Annual Meeting of Stockholders, which will be filed with the SEC within 120 days of the fiscal year ended December 31, 2020 (2021 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 March 11, 2021
Mark A. (Mac) McFarland	Chairman of the Board and Interim Chief Executive Officer since 2020; 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.	51
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.	44
Shawn M. Kerns	Executive Vice President - Operations since 2020; Executive Vice President - Operations and Engineering 2018 to 2020; 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.	50
Michael L. Preston	Senior Executive Vice President, Chief Administrative 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.	56

ITEM 11 EXECUTIVE COMPENSATION

The information required by this item is incorporated by reference from our 2021 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 2021 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 2021 Proxy Statement.

ITEM 14 PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated by reference from our 2021 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	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.
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).
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.

Exhibit Number	Exhibit Description
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 t1hrough 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	Tenth Amendment to the Credit Agreement, dated as of April 30, 2020, among California Resources Corporation, as the Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed May 6, 2020 and incorporated herein by reference).
10.8	Forbearance Agreement, dated as of June 2, 2020, by and among California Resources Corporation, as the Borrower, the other Guarantors party thereto, the various Lenders identified therein, and JP Morgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed June 8, 2020 and incorporated herein by reference).
10.9	Forbearance Agreement, dated as of June 2, 2020, by and among California Resources Corporation, as the Borrower, the other Guarantors party thereto, the various Lenders identified therein and the Bank of New York Mellon Trust Company, N.A., as Administrative Agent (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed June 8, 2020 and incorporated herein by reference).
10.10	Forbearance Agreement, dated as of June 2, 2020, by and among California Resources Corporation, as the Borrower, the other Guarantors party thereto, the various Lenders identified therein and the Bank of New York Mellon Trust Company, N.A., as Administrative Agent (filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed June 8, 2020 and incorporated herein by reference).
10.11	First Amendment to Forbearance Agreement, dated as of June 12, 2020, by and among California Resources Corporation, as the Borrower, the other Guarantors party thereto, the various Lenders identified therein, JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed June 15, 2020 and incorporated herein by reference).
10.12	First Amendment to Forbearance Agreement, dated as of June 12, 2020, by and among California Resources Corporation, as the Borrower, the other Guarantors party thereto, the various Lenders identified therein and The Bank of New York Mellon Trust Company, N.A., as Administrative Agent (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed June 15, 2020 and incorporated herein by reference).
10.13	First Amendment to Forbearance Agreement, dated as of June 12, 2020, by and among California Resources Corporation, as the Borrower, the other Guarantors party thereto, the various Lenders identified therein and The Bank of New York Mellon Trust Company, N.A., as Administrative Agent (filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed June 15, 2020 and incorporated herein by reference).
10.14	Second Amendment to Forbearance Agreement, dated as of June 30, 2020, by and among California Resources Corporation, the subsidiary guarantors party thereto, certain Lenders identified therein, JPMorgan Chase Bank, N.A., as Administrative Agent, a Lender and a Letter of Credit Issuer, and Bank of America, N.A., a Lender and a Letter of Credit Issuer (filed as Exhibit 10.1 to Registrant's Current Report on Form 8-K filed July 2, 2020 and incorporated herein by reference).
10.15	Second Amendment to Forbearance Agreement, dated as of June 30, 2020, by and among California Resources Corporation, as the Borrower, the subsidiary guarantors party thereto, the various Lenders identified therein and The Bank of New York Mellon Trust Company, N.A., as Administrative Agent (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed July 2, 2020 and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.16	Second Amendment to Forbearance Agreement, dated as of June 30, 2020, by and among California Resources Corporation, as the Borrower, the subsidiary guarantors party thereto, the various Lenders identified therein and The Bank of New York Mellon Trust Company, N.A., as Administrative Agent (filed as Exhibit 10.3 to the Registrant’s Current Report on Form 8-K filed July 2, 2020 and incorporated herein by reference).
10.17	Restructuring Support Agreement, dated as of July 15, 2020, by and among California Resources Corporation and the other parties named therein (filed as Exhibit 10.1 to the Registrant’s Current Report on Form 8-K filed July 16, 2020).
10.18	Senior Secured Superpriority Debtor-in-Possession Revolving Credit Facility Commitment Letter, dated as of July 15, 2020, by and among California Resources Corporation, certain of its subsidiaries and JPMorgan Chase Bank, N.A. (filed as Exhibit 10.2 to the Registrant’s Current Report on Form 8-K filed July 16, 2020).
10.19	Settlement and Assumption Agreement, dated as of July 15, 2020, by and among California Resources Corporation, California Resources Elk Hills, LLC, Elk Hills Power, LLC, ECR Corporate Holdings GP LLC, ECR I, L.P., SSF IV Energy I AIV 1, L.P., SSF IV Energy I AIV 2, L.P., AEOF ECR Holdings, L.P., and ECR Corporate Holdings, L.P. (filed as Exhibit 10.3 to the Registrant’s Current Report on Form 8-K filed July 16, 2020).
10.20	Backstop Commitment Agreement, dated as of July 15, 2020, among California Resources Corporation and the Backstop Parties hereto (filed as Exhibit 10.1 to the Registrant’s Current Report on Form 8-K filed July 17, 2020).
10.21	Senior Secured Superpriority Debtor-in-Possession Credit Agreement dated as of July 23, 2020, among California Resources Corporation, as the Borrower, the several lenders from time to time parties hereto, and JPMorgan Chase Bank, N.A., as Administrative Agent and as Sole Lead Arranger and Bookrunner (filed as Exhibit 10.1 to the Registrant’s Current Report on Form 8-K filed July 24, 2020).
10.22	Junior Secured Superpriority Debtor-in-Possession Credit Agreement dated as of July 23, 2020, among California Resources Corporation, as the Borrower, the several lenders from time to time parties hereto, and Alter Domus Products Corp., as Administrative Agent (filed as Exhibit 10.2 to the Registrant’s Current Report on Form 8-K filed July 24, 2020).
10.23	Amended and Restated Restructuring Support Agreement, dated as of July 24, 2020, by and among California Resources Corporation, certain of its subsidiaries and the Consenting Parties (as defined therein) (filed as Exhibit 10.3 to the Registrant’s Current Report on Form 8-K filed July 24, 2020).
10.24	Amended and Restated Backstop Commitment Agreement, dated as of July 24, 2020, by and among California Resources Corporation, certain of its subsidiaries and the Backstop Parties (as defined therein) (filed as Exhibit 10.4 to the Registrant’s Current Report on Form 8-K filed July 24, 2020).
10.25	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).
10.26	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 Alter Domus Products Corp., as Administrative Agent and Collateral Agent (filed as Exhibit 10.2 to the Registrant’s Current Report on Form 8-K filed November 2, 2020 and incorporated herein by reference).
10.27	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).
10.28	Note Purchase Agreement, dated as of October 27, 2020, by and among EHP Midco Holding Company, LLC, each of the Purchasers party thereto and Wilmington Trust, National Association, as Administrative Agent for the holders and as Collateral Agent for the secured parties (filed as Exhibit 10.5 to the Registrant’s Current Report on Form 8-K filed November 2, 2020 and incorporated herein by reference).
10.29	Owner Guaranty, dated as of October 27, 2020, by California Resources Corporation to and for the benefit of Wilmington Trust, National Association, as Collateral Agent for the secured parties (filed as Exhibit 10.6 to the Registrant’s Current Report on Form 8-K filed November 2, 2020 and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.30	Sponsor Support Agreement, dated as of October 27, 2020, by and among Elk Hills Power, LLC, California Resources Corporation and EHP Midco Holding Company, LLC (filed as Exhibit 10.7 to the Registrant's Current Report on Form 8-K filed November 2, 2020 and incorporated herein by reference).
10.31	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).
	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.
10.32	California Resources Corporation Executive Severance Plan, dated as of March 20, 2020 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed March 24, 2020 and incorporated herein by reference).
10.33	Quarterly Incentive Plan dated May 19, 2020 (filed as Exhibit 10.11 to the Registrant's Quarterly Report on Form 10-Q filed June 25, 2020 and incorporated herein by reference).
10.34	Notice and Severance Pay Plan dated May 26, 2020 (filed as Exhibit 10.12 to the Registrant's Quarterly Report on Form 10-Q filed June 25, 2020 and incorporated herein by reference).
10.35	Form of Quarterly Incentive Award (filed as Exhibit 10.9 to the Registrant's Quarterly Report on Form 10-Q filed June 25, 2020 and incorporated herein by reference).
10.36	Form of Retention Bonus Agreement (filed as Exhibit 10.10 to the Registrant's Quarterly Report on Form 10-Q filed June 25, 2020 and incorporated herein by reference).
10.37	Form of 2020 Nonstatutory Stock Option Award Terms and Conditions (filed as Exhibit 10.13 to the Registrant's Quarterly Report on Form 10-Q filed June 25, 2020 and incorporated herein by reference).
10.38	Form of 2020 Restricted Stock Unit Award Terms and Conditions (filed as Exhibit 10.14 to the Registrant's Quarterly Report on Form 10-Q filed June 25, 2020 and incorporated herein by reference).
10.39	Form of 2020 Performance Stock Unit Award Terms and Conditions (filed as Exhibit 10.15 to the Registrant's Quarterly Report on Form 10-Q filed June 25, 2020 and incorporated herein by reference).
10.40	Separation Agreement and General Release, dated August 18, 2020, by and between Marshall D. Smith and California Resources Corporation (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed August 18, 2020 and incorporated herein by reference).
10.41	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).
10.42*	Interim Chief Executive Officer Agreement, dated December 21, 2020, by and between Mark A. McFarland and California Resources Corporation.
10.43*	Separation Agreement and General Release, dated December 31, 2020, by and between Todd A. Stevens and California Resources Corporation.
10.44	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).
10.45*	Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award for Non-Employee Directors Grant Agreement.
10.46*	Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Term and Conditions.
10.47*	Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Term and Conditions.
10.48*	Form of California Resources Corporation 2021 Long Term Incentive Plan Performance Stock Unit Award Term and Conditions.
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.

Exhibit Number	Exhibit Description
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, 2020.
99.2*	Netherland, Sewell & Associates, Inc. Estimated Future Reserves Attributable to Certain Leasehold and Royalty Interests as of December 31, 2020.
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

March 11, 2021

By: /s/ Mark A. (Mac) McFarland

Mark A. (Mac) McFarland
Chairman of the Board and
Interim Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

	Title	Date
/s/ Mark A. (Mac) McFarland Mark A. (Mac) McFarland	Chairman of the Board and Interim Chief Executive Officer	March 11, 2021
/s/ Francisco J. Leon Francisco J. Leon	Executive Vice President and Chief Financial Officer	March 11, 2021
/s/ Roy Pineci Roy Pineci	Senior Vice President - Finance and Principal Accounting Officer	March 11, 2021
/s/ Douglas E. Brooks Douglas E. Brooks	Director	March 11, 2021
/s/ Tiffany (TJ) Thom Cepak Tiffany (TJ) Thom Cepak	Director	March 11, 2021
/s/ James N. Chapman James N. Chapman	Lead Independent Director	March 11, 2021
/s/ Julio M. Quintana Julio M. Quintana	Director	March 11, 2021
/s/ William B. Roby William B. Roby	Director	March 11, 2021
/s/ Brian Steck Brian Steck	Director	March 11, 2021

Annual Meeting

California Resources Corporation's annual meeting of stockholders will be held virtually at 11:00 a.m. Pacific Time on May 12, 2021. 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
Chairman of the Board, President,
Chief Executive Officer, and Director

Michael L. Preston
Senior Executive Vice President,
Chief Administrative Officer and General Counsel

Shawn M. Kerns
Executive Vice President,
Operations and Engineering

Francisco J. Leon
Executive Vice President,
and Chief Financial Officer

Board of Directors

Mark A. (Mac) McFarland
Chairman of the Board, President,
Chief Executive Officer, and Director

Douglas E. Brooks
Member of the Nominating & Governance Committee,
and Director

Tiffany (TJ) Thom Cepak
Chair of the Audit Committee,
Member of the Operations & Sustainability Committee,
and Director

James N. Chapman
Chair of the Compensation Committee,
Member of the Nominating & Governance Committee,
and Director

Julio M. Quintana
Member of the Audit Committee,
Member of the Operations & Sustainability Committee,
and Director

William B. Roby
Chair of the Operations & Sustainability Committee,
Member of the Audit Committee,
Member of the Compensation Committee,
and Director

Brian Steck
Chair of the Nominating & Governance Committee,
Member of the Compensation Committee,
and Director

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