



California Resources Generates a Record \$466 Million of Free Cash Flow¹ in 2021, Reports \$660 Million of Operating Cash Flow, Increases its Share Repurchase Program by 40% and Continues to Advance its Low Carbon Strategy

February 24, 2022

SANTA CLARITA, Calif.--(BUSINESS WIRE)-- California Resources Corporation (NYSE: CRC), an independent oil and natural gas company committed to energy transition in the sector, today reported fourth quarter and full year 2021 operational and financial results.

"2021 was a transformative year for CRC. We optimized our portfolio, maintained operational excellence, generated record free cash flow and advanced our Carbon Management Business," said Mac McFarland, President and Chief Executive Officer. "Our strong execution throughout the year and excellent financial results have allowed us to continue to demonstrate our commitment to shareholder returns. I am pleased to announce that the Board has authorized a \$100 million, or 40%, increase to our share repurchase program and extended the term through 2022. Operationally, we plan to sustain our oil and gas operations with a four drilling rig program throughout 2022. We expect to exit 2022 with net production of ~58,000 barrels of oil per day, similar to the rate that we exited 2021, even after the divestitures of the remaining Ventura assets and our non-operated Lost Hills working interest. Given this outlook, we expect to generate significant free cash flow¹ in 2022 after fully funding our plans to deploy approximately \$85 million into our Carbon Management Business."

Mr. McFarland continued, "CRC continues to see robust interest and incredible need for our Carbon Management Business. In 2022, we continue to target emitter contracts and are filing additional permit applications for our Carbon TerraVault projects. CRC remains focused on safely, responsibly and sustainably meeting California's energy demand today, and leveraging its position to help decarbonize California in the future."

Primary Highlights

- Reported net income attributable to common stock of \$612 million, or \$7.37 per diluted share. When adjusted for items analysts typically exclude from estimates including the release of the tax valuation allowance, noncash mark-to-market losses and gains on asset divestitures, the Company's adjusted net income¹ was \$506 million, or \$6.10 per diluted share
- Generated net cash provided by operating activities of \$660 million, adjusted EBITDAX¹ of \$860 million and free cash flow¹ of \$466 million in 2021
- Produced approximately 60,000 barrels of oil per day, with total capital expenditures of \$194 million in 2021
- Declared a quarterly dividend of \$0.17 per share of common stock, totaling \$13 million payable on March 16, 2022, to shareholders of record on March 7, 2022, with subsequent quarterly dividends subject to final determination and Board approval
- Repurchased an aggregate 5,023,188 shares for \$188 million through February 18, 2022, under the share repurchase program for an average price of \$37.29 per share
- In 2022, increased the share repurchase program by \$100 million to \$350 million in aggregate and extended the term of the program through December 31, 2022. After the repurchases through February 18, 2022, and the \$100 million increase, CRC has \$162 million available for future repurchases
- Sold non-operated working interest in certain horizons within the Lost Hills field for cash proceeds of \$55 million

Fourth Quarter 2021 Highlights

Financial

- Reported net income attributable to common stock of \$714 million, or \$8.71 per diluted share. When adjusted for items analysts typically exclude from estimates including the release of the tax valuation allowance, noncash mark-to-market losses and gains on asset divestitures, the Company's adjusted net income¹ was \$175 million, or \$2.13 per diluted share
- Generated net cash provided by operating activities of \$204 million, adjusted EBITDAX¹ of \$260 million and free cash flow¹ of \$138 million
- Closed the quarter with \$305 million of cash on hand, an undrawn credit facility and \$672 million of liquidity²

Operations

- Produced an average of 97,000 net barrels of oil equivalent (BOE) per day, including 59,000 barrels per day of oil, with quarterly capital expenditures of \$66 million

- Operated three drilling rigs in the San Joaquin Basin and one drilling rig in the Los Angeles Basin; drilled 39 wells (35 online in 4Q21)
- Operated 34 maintenance rigs

2022 Production Guidance & Capital Program³

During the first quarter of 2022, CRC's Elk Hills cryogenic gas plant (CGP1) will undergo maintenance that will result in a shut down for approximately six to eight weeks. CGP1 is approaching a 10-year inspection and CRC elected to pursue the plant turnaround in the first quarter to benefit from lower costs of materials and to optimize commodity yields throughout the summer of 2022. As a result of this turnaround, CRC expects a decrease in production of approximately 6,000 BOE per day (56% NGLs) in the first quarter of 2022, returning to pre-turnaround production levels in the second quarter of 2022. CRC also estimates a decrease in total daily production of ~2,000 BOE per day in 2022.

In February 2022, CRC sold its non-operated working interest in certain horizons within the Lost Hills field which had full year 2021 net production of approximately 1,900 barrels of oil per day (100% oil). See **Acquisitions and Divestitures** for additional information on this transaction.

CRC expects to produce between 90,000 and 93,000 BOE per day³ (~62% oil) in 2022. This range takes into account the full impact of the CGP1 turnaround as well as the Ventura and Lost Hills divestitures.

CRC's 2022 capital program³ targets a range of \$330 to \$375 million. The program includes \$300 to \$335 million for oil and gas operations, representing a ~64% increase over 2021 at the midpoint, and \$30 to \$40 million for carbon management projects. This level of expected spending is consistent with CRC's strategy of investing up to approximately 50% of its operating cash flow back into its exploration and production business.

At this level of spending, CRC expects to maintain oil production from exit to exit despite asset sales. CRC plans to run four drilling rigs in the Mount Poso, Elk Hills, Buena Vista and Wilmington fields, and will focus on high return opportunities and build off of the success of the 2021 drilling program.

TOTAL CRC GUIDANCE³	E&P 2022E	CMB 2022E	2022E
Net Total Production (Mboe/d)	93 - 90		93 - 90
Net Oil Production (Mbbbl/d)	60 - 56		60 - 56
Operating Costs (\$ millions)	\$640 - \$670		\$640 - \$670
CMB Expenses ⁴ (\$ millions)		\$30 - \$40	\$30 - \$40
Adjusted General and Administrative Expenses ¹ (\$ millions)	\$155 - \$175	\$10 - \$15	\$165 - \$190
Total Capital (\$ millions)	\$300 - \$335	\$30 - \$40	\$330 - \$375
<i>Drilling & Completions</i>	\$215 - \$225		\$215 - \$225
<i>Workovers</i>	\$25 - \$35		\$25 - \$35
<i>Facilities</i>	\$55 - \$65		\$55 - \$65
<i>Corporate & Other</i>	\$5 - \$10		\$5 - \$10
<i>Carbon Management Business</i>		\$30 - \$40	\$30 - \$40
Adjusted EBITDAX ¹ (\$ millions)	\$800 - \$940	(\$40) - (\$55)	\$745 - \$900
Free Cash Flow ^{1,5} (\$ millions)	\$350 - \$450	(\$70) - (\$95)	\$255 - \$380
Cash Tax as % of Pre-Tax Income			10% - 18%

Acquisitions and Divestitures

CRC divested the vast majority of its Ventura basin assets in the second half of 2021 and recognized a gain of \$120 million during the year ended December 31, 2021. CRC expects to divest its remaining assets in the Ventura basin during the first half of 2022.

In February 2022, CRC sold its 50% non-operated working interest in certain horizons of the Lost Hills field located in the San Joaquin Basin for cash proceeds of \$55 million (before transaction costs and purchase price adjustments) which will be used for general corporate purposes. CRC retained an option to capture, transport and store 100% of the carbon emissions from steam generators across the Lost Hills field for future carbon management projects. CRC also retained 100% of the deep rights and related seismic data.

Sustainability Update

In December 2021, CRC was recognized at the Leadership Level ranking for 2021 climate disclosure by CDP for the third year in a row. Once again, CRC received the highest ranking among all U.S. oil and gas companies, tying for first with one other U.S.-based E&P with global operations. Scoring at CDP's Leadership Level for three years in a row further highlights CRC's value of ESG leadership in its transparent environmental reporting and disclosure practices as it values being a differentiated and reputable low carbon intensity E&P producer in California.

CRC also continues to prioritize its ESG initiatives and making progress toward its Full-Scope Net Zero goal by 2045. CRC defines Full-Scope Net Zero as achieving permanent storage of captured or removed carbon emissions in a volume equal to all of its scope 1, 2, and 3 emissions by 2045. CRC intends to achieve this goal by targeting investing approximately 25% of its operating cash flows in carbon management projects. These projects include Carbon TerraVault, which is in the early stages of permitting and developing several carbon capture and permanent storage projects in suitable reservoirs. Separately, CRC is evaluating the feasibility of its CalCapture project which utilizes the Elk Hills power plant as the emissions source for CO₂ enhanced oil recovery in its Elk Hills field. The Company is also pursuing multiple front-of-the-meter and behind-the-meter solar projects. CRC remains committed to advancing emissions reducing projects that are aligned with the state of California's 2045 net zero ambitions and puts it ahead of the net zero goals in the Paris Agreement. The Company believes that its Full-Scope Net Zero goal and its cash flow prioritization are a significant ESG differentiator.

During 2022, CRC plans to apply for additional permits to meet the near-term focus of 200 million metric tons of permanent CO₂ storage target for Carbon TerraVault projects. The Company expects to provide additional details about these ongoing permitting efforts and Carbon TerraVault project participants by the end of 2022. Additionally, CRC continues to progress its behind-the-meter solar projects for a total capacity of ~39 megawatts. These solar projects are expected to begin commercial operations sometime in 2023.

Board Enhancement

On December 14, 2021, CRC's Board of Directors elected one new Board member, Alejandra (Ale) Veltmann. Ms. Veltmann will serve as the Chair of the Audit Committee of the Board and qualifies as an independent director and audit committee financial expert.

Ms. Veltmann has over 28 years of experience as a global financial leader of publicly traded entities, private entrepreneurial companies and global accounting firms. Since 2018, she has served as founder, CEO and sole director of ESG Lynk, a leading sustainability reporting company. From 2010 to 2018, she worked in various roles including Vice President and Chief Accounting Officer and Corporate Controller. Prior to that, Ms. Veltmann worked in various capacities at KPMG LLP from 1995 to 2002 and before that at Arthur Andersen LLP from 1992 to 1995. Since 2021, she has served as a director and chair of the Audit Committee for Structural Integrity Associates, a provider of life cycle engineering solutions. Ms. Veltmann has served as a Board member of The University of New Mexico Robert O. Anderson School of Management since 2018, and as an Advisory Council member of the K.B. Hutchison Center for Energy, Law & Business at The University of Texas at Austin since 2019. Please see www.crc.com for more details.

Fresh Start Accounting and Predecessor and Successor Periods

CRC qualified for and adopted fresh start accounting upon its emergence from bankruptcy on October 27, 2020, at which point CRC became a new entity for financial reporting purposes. CRC adopted an accounting convenience date of October 31, 2020, for the application of fresh start accounting. As a result of the application of fresh start accounting and the effects of the implementation of the joint 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 ending on or prior to October 31, 2020, and references to "Successor" refer to the Company for periods subsequent to October 31, 2020.

Fourth Quarter 2021 Results

	Successor	Successor	Predecessor	Combined
	4th Quarter	4th Quarter	4th Quarter	4th Quarter
	2021	2020	2020	2020
(\$ and shares in millions, except per share amounts)				
Statements of Operations:				
Revenues				
Total operating revenues	\$ 634	\$ 152	\$ 149	\$ 301
Operating Expenses				
Total operating expenses	422	258	151	409
Gain on asset divestitures	120	—	—	—
Operating Income (Loss)	\$ 332	\$ (106)	\$ (2)	\$ (108)
Net Income (Loss) Attributable to Common Stock	\$ 714	\$ (123)	\$ 3,985	\$ 3,862
Net income (loss) attributable to common stock per share - basic	\$ 8.91	\$ (1.48)	\$ 80.20	\$ —
Net income (loss) attributable to common stock per share - diluted	\$ 8.71	\$ (1.48)	\$ 80.20	\$ —
Adjusted net income (loss) ¹	\$ 175	\$ 28	\$ (20)	\$ 8

Adjusted net income (loss) ¹ per share - diluted	\$ 2.13	\$ 0.34	\$ (0.40)	\$ —
Weighted-average common shares outstanding - basic	80.1	83.3	49.5	—
Weighted-average common shares outstanding - diluted	82.0	83.3	49.5	—
Adjusted EBITDAX ¹	\$ 260	\$ 83	\$ 33	\$ 116
	Successor	Successor	Predecessor	Combined
	4th Quarter	4th Quarter	4th Quarter	4th Quarter
	2021	2020	2020	2020

(\$ in millions)

Cash Flow Data:

Net cash provided (used) by operating activities	\$ 204	\$ (12)	\$ (23)	\$ (35)
Net cash used in investing activities	\$ (10)	\$ (7)	\$ (2)	\$ (9)
Net cash (used) provided by financing activities	\$ (78)	\$ (156)	\$ 106	\$ (50)

Full Year 2021 Results

	Successor	Successor	Predecessor	Combined
	Total Year	Total Year	Total Year	Total Year
	2021	2020	2020	2020

(\$ and shares in millions, except per share amounts)

Statements of Operations:

Revenues

Total operating revenues	\$ 1,889	\$ 152	\$ 1,407	\$ 1,559
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Costs

Total operating costs	1,720	258	3,186	3,444
Gain on asset divestitures	124	—	—	—

Operating Income (Loss)	\$ 293	\$ (106)	\$ (1,779)	\$ (1,885)
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Net Income (Loss) Attributable to Common Stock	\$ 612	\$ (123)	\$ 1,889	\$ 1,766
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Net income (loss) attributable to common stock per share - basic	\$ 7.46	\$ (1.48)	\$ 40.59	\$ —
Net income (loss) attributable to common stock per share - diluted	\$ 7.37	\$ (1.48)	\$ 40.42	\$ —
Adjusted net income (loss) ¹	\$ 506	\$ 28	\$ (285)	\$ (257)
Adjusted net income (loss) ¹ per share - diluted	\$ 6.10	\$ 0.34	\$ (2.98)	\$ —
Weighted-average common shares outstanding - basic	82.0	83.3	49.4	—
Weighted-average common shares outstanding - diluted	83.0	83.3	49.6	—
Adjusted EBITDAX ¹	\$ 860	\$ 83	\$ 406	\$ 489

	Successor	Successor	Predecessor	Combined
	Total Year	Total Year	Total Year	Total Year
	2021	2020	2020	2020

(\$ in millions)

Cash Flow Data:

Net cash provided (used) by operating activities	\$ 660	\$ (12)	\$ 118	\$ 106
Net cash used in investing activities	\$ (161)	\$ (7)	\$ (30)	\$ (37)
Net cash (used) provided by financing activities	\$ (222)	\$ (156)	\$ 98	\$ (58)

Review of Operating and Financial Results

Total daily net production volumes decreased 6% from 103,000 BOE per day for the combined fourth quarter of 2020 to 97,000 BOE per day for the fourth quarter of 2021. Total daily net production volumes decreased 10% from 111,000 BOE per day for the combined year ended December 31, 2020 to 100,000 BOE per day for the same period in 2021. The decrease for both periods was largely a result of natural production declines. CRC suspended its drilling activity in the first quarter of 2020 and temporarily shut-in production in the second quarter of 2020 in response to the economic conditions at that time. CRC increased its capital investment and re-started its drilling program during 2021. PSCs at CRC's Long Beach assets negatively impacted oil production by approximately 3,000 barrels per day in both the quarter and the year ended December 31, 2021, compared to the same prior-year periods. CRC divested the vast majority of its assets in the Ventura basin which resulted in a decrease of 2,000 BOE per day beginning in the fourth quarter of 2021. This decrease was partially offset by improved operational results from CRC's 2021 drilling program and its acquisition of the working interests in certain joint venture wells held by Macquarie Infrastructure and Real Assets Inc. (MIRA) in the third quarter of 2021 which increased oil production by 1,000 barrels per day. See Attachment 3 for

further information on production.

Realized oil prices, including the effect of settled hedges, increased by \$16.61 per barrel from \$44.39 per barrel in the combined fourth quarter of 2020 to \$61.00 per barrel in the fourth quarter of 2021. For the year ended December 31, 2021, realized oil prices, including the effect of settled hedges, increased by \$12.52 to \$56.05 from \$43.53 in the same period of 2020. Realized oil prices were higher in the fourth quarter and full year of 2021 compared to the same prior-year periods as oil demand was bolstered by the re-opening of economies and the easing of mobility restrictions related to the COVID-19 pandemic. Prices also increased due to a rise in domestic demand and lower supply caused by reduced investment in the U.S. upstream oil and gas sector as well as supply management by OPEC members. See Attachment 4 for further information on prices.

Adjusted EBITDAX¹ for the fourth quarter of 2021 and for the year ended December 31, 2021, was \$260 million and \$860 million, respectively. See table below for further information on the Company's net cash provided by operating activities, capital investments and free cash flow¹ during the same periods.

FREE CASH FLOW¹

Management uses free cash flow, which is defined by us as net cash provided by operating activities less capital investments, as a measure of liquidity. The following table presents a reconciliation of our net cash provided by operating activities to free cash flow. We have excluded one-time costs for bankruptcy related fees during 2021 and 2020 as a supplemental measure of free cash flow.

	Successor	Combined	Successor	Combined
(\$ millions)	4th Quarter	4th Quarter	Total Year	Total Year
	2021	2020	2021	2020
Net cash provided (used) by operating activities	\$ 204	\$ (35)	\$ 660	\$ 106
Capital investments	(66)	(10)	(194)	(47)
Free cash flow ¹	138	(45)	466	59
One-time bankruptcy related fees	1	39	6	113
Free cash flow ¹ , after special items	\$ 139	\$ (6)	\$ 472	\$ 172

The following table presents key operating data for CRC's oil and gas operations, on a per BOE basis, for the periods presented below. Energy operating costs consist of purchases of natural gas used to generate electricity, purchased electricity and internal costs to generate electricity used in CRC's operations. Non-energy operating costs equal total operating costs less energy and gas processing costs. However, non-energy operating costs include the costs of purchasing natural gas to generate steam for its steamfloods.

OPERATING COSTS PER BOE

The reporting of our PSCs creates a difference between reported operating costs, which are for the full field, and reported volumes, which are only our net share, inflating the per barrel operating costs. The following table presents operating costs after adjusting for the excess costs attributable to PSCs.

	Successor	Combined	Successor	Combined
(\$ per Boe)	4th Quarter	4th Quarter	Total Year	Total Year
	2021	2020	2021	2020
Energy operating costs	\$ 5.47	\$ 4.39	\$ 5.09	\$ 3.95
Gas processing costs	0.41	0.59	0.54	0.55
Non-energy operating costs	14.57	12.44	13.76	10.95
Operating costs	\$ 20.45	\$ 17.42	\$ 19.39	\$ 15.45
Excess costs attributable to PSCs	(2.13)	(1.13)	(1.83)	(0.89)
Operating costs, excluding effects of PSCs ^(a)	\$ 18.32	\$ 16.29	\$ 17.56	\$ 14.56

(a) Operating costs, excluding effects of PSCs is a non-GAAP measure.

Energy operating costs for the three months ended December 31, 2021, were \$5.47 per BOE, which was an increase of \$1.08 per BOE or 25% from \$4.39 per BOE for the same period of 2020. Energy operating costs for the year ended December 31, 2021, were \$5.09 per BOE, which was an increase of \$1.14 per BOE or 29% from \$3.95 per BOE for the same period of 2020. This increase was primarily a result of higher prices for purchased natural gas, which CRC used to generate electricity for its operations, and for purchased electricity.

Non-energy operating costs for the three months ended December 31, 2021, were \$14.57 per BOE, which was an increase of

\$2.13 per BOE, or 17%, from \$12.44 per BOE for the same period of 2020. Non-energy operating costs for the year ended December 31, 2021, were \$13.76 per BOE, which was an increase of \$2.81 per BOE, or 26%, from \$10.95 per BOE for the same period of 2020. This increase was primarily a result of higher downhole maintenance activity in 2021 which was deferred in 2020 as CRC shut-in wells and suspended surface maintenance activity due to the COVID-19 pandemic. Additionally, non-energy operating costs increased in 2021 due to higher prices for natural gas which CRC uses to generate steam for its steamfloods. Partially offsetting these increases were lower labor-related costs from headcount reductions in late 2020 and early 2021 and reduced employee benefits beginning in the second quarter of 2021. Although higher natural gas prices in 2021 increased CRC's operating costs, higher prices have a net positive effect on its operating results due to higher revenue from sales of this commodity which it also produces.

General and administrative (G&A) expenses were \$53 million for the fourth quarter of 2021, compared to \$59 million in the same prior-year period. The decrease in G&A expenses for the fourth quarter is due to changes to the variable portion of our incentive compensation program from the prior year as well as lower labor-related costs as a result of workforce reductions that occurred in the first quarter of 2021 and employee benefit reductions in the second quarter of 2021. For the year ended December 31, 2021, G&A expenses were \$200 million compared to \$252 million in the same prior-year period. The decrease in G&A expenses for the year ended December 31, 2021, reflects lower labor-related costs as a result of workforce reductions that occurred in the second half of 2020 and the first quarter of 2021 as well as employee benefit reductions in the second quarter of 2021. The remaining decrease was also due to lower spending across a number of cost categories. The decreases from the fourth quarter and the year ended December 31, 2021, were partially offset by an increase in compensation expense related to equity-settled awards granted to executives and directors in 2021.

Balance Sheet and Liquidity Update

CRC's aggregate commitment under the Revolving Credit Facility was set at \$492 million as of December 31, 2021. The borrowing base for the Revolving Credit Facility, currently \$1.2 billion, will be redetermined semi-annually each April and October.

As of December 31, 2021, CRC had liquidity of \$672 million, which consisted of \$305 million in cash and \$367 million of available borrowing capacity under its Revolving Credit Facility.

In February 2022, CRC obtained additional commitments from new lenders increasing its aggregate commitment to \$552 million from \$492 million. After taking into account these additional commitments, the available borrowing capacity under CRC's Revolving Credit Facility increased by \$60 million.

CRC expects to begin paying cash income taxes. CRC's tax paying status depends on a number of factors, including the amount and type of CRC's capital spend, cost structure and activity levels. CRC expects to focus on asset retirement activities over the next several years to reduce its idle well inventory. CRC believes it has sufficient sources of liquidity to meet its obligations for the next twelve months.

Dividend Strategy

On February 23, 2022, the Board of Directors of CRC declared a regular quarterly dividend of \$0.17 per share of common stock. The dividend is payable to shareholders of record on March 7, 2022, and will be paid on March 16, 2022.

Reserves

As of December 31, 2021, CRC's proved reserves totaled an estimated 480 million BOE, of which 405 million BOE was proved developed and 75 million BOE was proved undeveloped. The estimated future net cash flows of our proved reserve volumes had a PV-10¹ value of \$6.17 billion. These estimates were based on SEC pricing and the average realized prices for estimating CRC's PV-10¹ of cash flows as of December 31, 2021, were \$68.73 per barrel for oil, \$52.81 per barrel for NGLs and \$3.99 per Mcf for natural gas.

PV-10 AND STANDARDIZED MEASURE

The following table presents a reconciliation of the GAAP financial measure of Standardized Measure of discounted future net cash flows (Standardized Measure) to the non-GAAP financial measure of PV-10:

(\$ millions)	December 31, 2021
Standardized Measure of discounted future net cash flows	\$ 4,549
Present value of future income taxes discounted at 10%	1,624
PV-10 of cash flows (*)	\$ 6,173

(*) PV-10 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 prescribed pricing assumptions for the period. PV-10 differs from Standardized Measure because Standardized Measure includes 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.

Operational Update

During the fourth quarter of 2021, CRC operated an average of three drilling rigs in the San Joaquin Basin and one drilling rig in the Los Angeles Basin. During the quarter, CRC drilled 39 net wells and brought online 35 wells. See Attachment 3 for further information on CRC's production results by basin. CRC exited the quarter with an average daily net production of 95,100 BOE per day, including 58,500 barrels per day of oil.

Upcoming Investor Conference Participation

CRC's executives will be participating in the following virtual and in-person events in February 2022 and March 2022:

- Credit Suisse 27th Annual Energy Summit on February 28 - March 2, 2022, in Vail, CO
- Morgan Stanley Energy and Power Conference on February 28 - March 2, 2022, in New York City, NY
- Mizuho 6th Annual Virtual Energy Summit on March 14 - 15
- Scotia Howard Weil 50th Annual Energy Conference on March 21 - 24, 2022, in New Orleans, LA

CRC's presentation materials will be available the day of the events on the Events and Presentations page in the Investor Relations section on www.crc.com.

Conference Call Details

To participate in the conference call scheduled for later today at 1:00 p.m. Eastern Time, please dial (877) 328-5505 (International calls please dial +1 (412) 317-5421) or access via webcast at www.crc.com 15 minutes prior to the scheduled start time to register. Participants may also pre-register for the conference call at <https://dpreregister.com/sreg/10162383/f019f7b40d>. A digital replay of the conference call will be archived for approximately 90 days and supplemental slides for the conference call will be available online in the Investor Relations section of www.crc.com.

¹ See Attachment 2 for the non-GAAP financial measures of adjusted EBITDAX, operating costs per BOE (excluding effects of PSCs), adjusted net income (loss), adjusted net income (loss) per share - basic and diluted), free cash flow and free cash flow, after special items including reconciliations to their most directly comparable GAAP measure, where applicable. For the full year 2022 estimates of the non-GAAP measures of adjusted EBITDAX and free cash flow, including reconciliations to their most directly comparable GAAP measure, see Attachment 7. See the reserves section for definitions and a reconciliation for the non-GAAP financial measure of PV-10.

² Calculated as \$305 million of cash plus \$492 million of capacity on CRC's Revolving Credit Facility less \$125 million in outstanding letters of credit.

³ 2022 guidance assumes prices of \$82.50 per barrel of oil, NGL realizations consistent with prior years and NYMEX gas of \$4.00 per mcf. CRC's share of production under PSCs decreases when commodity prices rise and increases when prices fall.

⁴ CMB expenses include start-up expenditures.

⁵ 2022E E&P Free Cash Flow includes settled ARO liabilities in the range of \$60 million - \$64 million.

About California Resources Corporation

California Resources Corporation (CRC) is an independent oil and natural gas company committed to energy transition in the sector. CRC has some of the lowest carbon intensity production in the US and we are focused on maximizing the value of our land, mineral and technical resources for decarbonization by developing carbon capture and storage (CCS) and other emissions reducing projects. For more information about CRC, please visit www.crc.com.

Forward-Looking Statements

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

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

- fluctuations in commodity prices and the potential for sustained low oil, natural gas and natural gas liquids prices;
- legislative or regulatory changes, including those related to (i) drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, (ii) managing energy, water, land, greenhouse gases (GHGs) or other emissions, (iii) protection of health, safety and the environment, (iv) tax credits or other incentives, or (v) transportation, marketing and sale of our products;
- availability or timing of, or conditions imposed on, permits and approvals necessary for drilling or development projects;
- changes in business strategy and CRC's capital plan;
- lower-than-expected production, reserves or resources from development projects or acquisitions, or higher-than-expected decline rates;
- incorrect estimates of reserves and related future cash flows and the inability to replace reserves;
- the recoverability of resources and unexpected geologic conditions;
- CRC's ability to realize the benefits of business strategies and initiatives related to energy transition, including carbon capture and storage projects and other renewable energy efforts;
- CRC's ability to finance and implement its carbon capture and storage projects;
- global geopolitical, socio-demographic and economic trends and technological innovations;
- changes in our dividend policy and our ability to declare future dividends;
- production-sharing contracts' effects on production and operating costs;
- limitations on CRC's financial flexibility due to existing and future debt;
- insufficient cash flow to fund planned investments, interest payments on our debt, stock repurchases or changes to CRC's capital plan;
- insufficient capital or liquidity 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;
- joint ventures and acquisitions and CRC's ability to achieve expected synergies;
- CRC's ability to utilize its net operating loss carryforwards to reduce its income tax obligations;
- CRC's ability to successfully gather and verify data regarding emissions, its environmental impacts and other initiatives;
- the compliance of various third parties with CRC's policies and procedures and legal requirements as well as contracts CRC enters into in connection with its climate-related initiatives;
- the effect of CRC's stock price on costs associated with incentive compensation;
- changes in the intensity of competition in the oil and gas industry;
- effects of hedging transactions;
- equipment, service or labor price inflation or unavailability;
- climate-related conditions and weather events;
- 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
- other factors discussed in Part I, Item 1A – Risk Factors in CRC's Annual Report on Form 10-K and its other SEC filings available at www.crc.com.

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

Attachment 1

SUMMARY OF RESULTS

	Fourth Quarter			
	Successor 2021	Successor 2020	Predecessor 2020	Combined (Non-GAAP) 2020
(\$ and shares in millions, except per share amounts)				
Statements of Operations:				
Revenues				
Oil, natural gas and NGL sales	\$ 589	\$ 237	\$ 105	\$ 342
Net (loss) gain from commodity derivatives	(73)	(141)	16	(125)
Sales of purchased natural gas	71	38	15	53
Electricity sales	41	15	11	26
Other revenue	6	3	2	5
Total operating revenues	634	152	149	301
Operating Expenses				
Operating costs	182	114	51	165
General and administrative expenses	53	40	19	59

Depreciation, depletion and amortization	53	34	32	66
Taxes other than on income	32	10	13	23
Exploration expense	1	1	1	2
Purchased natural gas expense	52	24	11	35
Electricity generation expenses	26	10	6	16
Transportation costs	14	8	4	12
Accretion expense	11	8	3	11
Other operating expenses, net	(2)	9	11	20
Total operating expenses	422	258	151	409
Gain on asset divestitures	120	—	—	—
Operating Income (Loss)	332	(106)	(2)	(108)
Non-Operating (Expenses) Income				
Reorganization items, net	(1)	(3)	3,994	3,991
Interest and debt expense, net	(14)	(11)	(6)	(17)
Net (loss) gain on early extinguishment of debt	—	—	—	—
Other non-operating expenses, net	1	(5)	9	4
Income (Loss) Before Income Taxes	318	(125)	3,995	3,870
Income taxes	396	—	—	—
Net Income (loss)	714	(125)	3,995	3,870
Net loss (income) attributable to noncontrolling interests	—	2	(10)	(8)
Net Income (Loss) Attributable to Common Stock	\$ 714	\$ (123)	\$ 3,985	\$ 3,862
Net income (loss) attributable to common stock per share - basic	\$ 8.91	\$ (1.48)	\$ 80.20	\$ —
Net income (loss) attributable to common stock per share - diluted	\$ 8.71	\$ (1.48)	\$ 80.20	\$ —
Adjusted net income (loss)	\$ 175	\$ 28	\$ (20)	\$ 8
Adjusted net income (loss) per share - basic	\$ 2.18	\$ 0.34	\$ (0.40)	\$ —
Adjusted net income (loss) per share - diluted	\$ 2.13	\$ 0.34	\$ (0.40)	\$ —
Weighted-average common shares outstanding - basic	80.1	83.3	49.5	—
Weighted-average common shares outstanding - diluted	82.0	83.3	49.5	—
Adjusted EBITDAX	\$ 260	\$ 83	\$ 33	\$ 116
Effective tax rate	(125)%	0%	0%	0%

SUMMARY OF RESULTS

	Total Year			
	Successor 2021	Successor 2020	Predecessor 2020	Combined (Non-GAAP) 2020
(\$ and shares in millions, except per share amounts)				
Statements of Operations:				
Revenues				
Oil, natural gas and NGL sales	\$ 2,048	\$ 237	\$ 1,092	\$ 1,329
Net (loss) gain from commodity derivatives	(676)	(141)	91	(50)
Sales of purchased natural gas	312	38	124	162
Electricity sales	172	15	86	101
Other revenue	33	3	14	17
Total operating revenues	1,889	152	1,407	1,559
Operating Expenses				
Operating costs	705	114	511	625

General and administrative expenses	200	40	212	252
Depreciation, depletion and amortization	213	34	328	362
Asset impairments	28	—	1,736	1,736
Taxes other than on income	145	10	134	144
Exploration expense	7	1	10	11
Purchased natural gas expense	196	24	78	102
Electricity generation expenses	96	10	53	63
Transportation costs	51	8	35	43
Accretion expense	50	8	33	41
Other operating expenses, net	29	9	56	65
Total operating expenses	1,720	258	3,186	3,444
Gain on asset divestitures	124	—	—	—
Operating Income (Loss)	293	(106)	(1,779)	(1,885)
Non-Operating (Expenses) Income				
Reorganization items, net	(6)	(3)	4,060	4,057
Interest and debt expense, net	(54)	(11)	(206)	(217)
Net (loss) gain on early extinguishment of debt	(2)	—	5	5
Other non-operating expenses, net	(2)	(5)	(84)	(89)
Income (Loss) Before Income Taxes	229	(125)	1,996	1,871
Income taxes	396	—	—	—
Net Income (Loss)	625	(125)	1,996	1,871
Net (income) loss attributable to noncontrolling interests	(13)	2	(107)	(105)
Net Income (Loss) Attributable to Common Stock	\$ 612	\$ (123)	\$ 1,889	\$ 1,766
Net income (loss) attributable to common stock per share - basic	\$ 7.46	\$ (1.48)	\$ 40.59	\$ —
Net income (loss) attributable to common stock per share - diluted	\$ 7.37	\$ (1.48)	\$ 40.42	\$ —
Adjusted net income (loss)	\$ 506	\$ 28	\$ (285)	\$ (257)
Adjusted net income (loss) per share - basic	\$ 6.17	\$ 0.34	\$ (2.98)	\$ —
Adjusted net income (loss) per share - diluted	\$ 6.10	\$ 0.34	\$ (2.98)	\$ —
Weighted-average common shares outstanding - basic	82.0	83.3	49.4	—
Weighted-average common shares outstanding - diluted	83.0	83.3	49.6	—
Adjusted EBITDAX	\$ 860	\$ 83	\$ 406	\$ 489
Effective tax rate	(173%)	0%	0%	0%

(\$ in millions)	Fourth Quarter			
	Successor 2021	Successor 2020	Predecessor 2020	Combined (Non-GAAP) 2020
Cash Flow Data:				
Net cash provided (used) by operating activities	\$ 204	\$ (12)	\$ (23)	\$ (35)
Net cash used in investing activities	\$ (10)	\$ (7)	\$ (2)	\$ (9)
Net cash (used) provided by financing activities	\$ (78)	\$ (156)	\$ 106	\$ (50)

(\$ in millions)	Total Year			
	Successor 2021	Successor 2020	Predecessor 2020	Combined (Non-GAAP) 2020

Cash Flow Data:

Net cash provided (used) by operating activities	\$ 660	\$ (12)	\$ 118	\$ 106
Net cash used in investing activities	\$ (161)	\$ (7)	\$ (30)	\$ (37)
Net cash (used) provided by financing activities	\$ (222)	\$ (156)	\$ 98	\$ (58)

	December 31,	December 31,
(\$ and shares in millions)	2021	2020

Selected Balance Sheet Data:

Total current assets	\$ 753	\$ 329
Property, plant and equipment, net	\$ 2,599	\$ 2,655
Deferred tax asset	\$ 396	\$ —
Total current liabilities	\$ 854	\$ 473
Long-term debt, net	\$ 589	\$ 597
Noncurrent asset retirement obligations	\$ 438	\$ 547
Stockholders' Equity	\$ 1,688	\$ 1,182

Outstanding shares	79.3	83.3
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GAINS AND LOSSES FROM COMMODITY DERIVATIVES

	Fourth Quarter			
(\$ millions)	Successor 2021	Successor 2020	Predecessor 2020	Combined 2020
Non-cash derivative gain (loss) - excluding noncontrolling interest	\$ 26	\$ (138)	\$ 13	\$ (125)
Non-cash derivative loss - noncontrolling interest	—	(2)	—	(2)
Total non-cash changes	26	(140)	13	(127)
Net (payments) proceeds on settled commodity derivatives	(99)	(1)	3	2
Net (loss) gain from commodity derivatives	<u>\$ (73)</u>	<u>\$ (141)</u>	<u>\$ 16</u>	<u>\$ (125)</u>
	Total Year			
(\$ millions)	Successor 2021	Successor 2020	Predecessor 2020	Combined 2020
Non-cash derivative loss - excluding noncontrolling interest	\$ (357)	\$ (138)	\$ (19)	\$ (157)
Non-cash derivative (loss) gain - noncontrolling interest	—	(2)	2	—
Total non-cash changes	(357)	(140)	(17)	(157)
Net (payments) proceeds on settled commodity derivatives	(319)	(1)	108	107
Net (loss) gain from commodity derivatives	<u>\$ (676)</u>	<u>\$ (141)</u>	<u>\$ 91</u>	<u>\$ (50)</u>

CAPITAL INVESTMENTS

	Fourth Quarter			
(\$ millions)	Successor 2021	Successor 2020	Predecessor 2020	Combined 2020
Internally funded capital	\$ 66	\$ 7	\$ 3	\$ 10
<i>Capital investments not included on our financial statements:</i>				
Alpine funded capital	—	(1)	—	(1)
Total capital program	<u>\$ 66</u>	<u>\$ 6</u>	<u>\$ 3</u>	<u>\$ 9</u>
	Total Year			

(\$ millions)	Successor 2021	Successor 2020	Predecessor 2020	Combined 2020
Internally funded capital	\$ 194	\$ 7	\$ 40	\$ 47
<i>Capital investments not included on our financial statements:</i>				
MIRA funded capital	—	—	1	1
Alpine funded capital	—	(1)	93	92
Total capital program	<u>\$ 194</u>	<u>\$ 6</u>	<u>\$ 134</u>	<u>\$ 140</u>

Attachment 2

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

To supplement the presentation of its financial results prepared in accordance with U.S generally accepted accounting principles (GAAP), management uses certain non-GAAP measures to assess its financial condition, results of operations and cash flows. The non-GAAP measures include adjusted net income (loss), adjusted EBITDAX, adjusted EBITDAX margin, discretionary cash flow, free cash flow and operating costs per BOE, among others. These measures are also widely used by the industry, the investment community and our lenders. Although these are non-GAAP measures, the amounts included in the calculations were computed in accordance with GAAP. Certain items excluded from these non-GAAP measures are significant components in understanding and assessing our financial performance, such as our cost of capital and tax structure, as well as the effect of acquisition and development costs of our assets. Management believes that the non-GAAP measures presented, when viewed in combination with its financial and operating results prepared in accordance with GAAP, provide a more complete understanding of the factors and trends affecting the Company's performance. The non-GAAP measures presented herein may not be comparable to other similarly titled measures of other companies. Below are additional disclosures regarding each of the non-GAAP measures reported in this press release, including reconciliations to their most directly comparable GAAP measure where applicable.

ADJUSTED NET INCOME (LOSS)

Adjusted net income (loss) and adjusted net income (loss) per share are non-GAAP measures. We define adjusted net income as net income excluding the effects of significant transactions and events that affect earnings but vary widely and unpredictably in nature, timing and amount. These events may recur, even across successive reporting periods. Management believes these non-GAAP measures provide useful information to the industry and the investment community interested in comparing our financial 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 and net income attributable to common stock per share to the non-GAAP financial measure of adjusted net income (loss) and adjusted net income (loss) per share.

(\$ millions, except per share amounts)	Fourth Quarter		Total Year	
	Successor 2021	Combined (Non-GAAP) 2020	Successor 2021	Combined (Non-GAAP) 2020
Net income	\$ 714	\$ 3,870	\$ 625	\$ 1,871
Net income attributable to noncontrolling interests	—	(8)	(13)	(105)
Net income attributable to common stock	714	3,862	612	1,766
Unusual, infrequent and other items:				
Non-cash (income) loss from commodity derivatives, excluding noncontrolling interest	(26)	125	357	157
Asset impairments	—	—	28	1,736
Reorganization items, net	1	(3,991)	6	(4,057)
Legal and professional fees related to our reorganization	—	—	—	65
Severance and termination costs	—	5	15	15
Net loss (gain) on early extinguishment of debt	—	—	2	(5)
Deficiency payment on pipeline delivery contract	—	—	—	20
Power plant maintenance	—	—	—	7
Incentive and retention award modifications	—	—	—	4
Write-off deferred financing costs	—	—	—	4
Gain on asset divestitures	(120)	—	(124)	—
Ad valorem late payment penalties	—	—	—	4

Rig termination expenses	—	2	2	5
Other, net	2	5	4	22
Total unusual, infrequent and other items	(143)	(3,854)	290	(2,023)
Valuation allowance	(396)	—	(396)	—
Adjusted net income (loss) attributable to common stock	<u>\$ 175</u>	<u>\$ 8</u>	<u>\$ 506</u>	<u>\$ (257)</u>
Net income attributable to common stock per share - basic	\$ 8.91	\$ —	\$ 7.46	\$ —
Net income attributable to common stock per share - diluted	\$ 8.71	\$ —	\$ 7.37	\$ —
Adjusted net income per share - basic	\$ 2.18	\$ —	\$ 6.17	\$ —
Adjusted net income per share - diluted	\$ 2.13	\$ —	\$ 6.10	\$ —

FREE CASH FLOW

Management uses free cash flow, which is defined by us as net cash provided by operating activities less capital investments, as a measure of liquidity. The following table presents a reconciliation of our net cash provided by operating activities to free cash flow. We have excluded one-time costs for bankruptcy related fees during 2021 and 2020 as a supplemental measure of our free cash flow.

(\$ millions)	Fourth Quarter		Total Year	
	Successor 2021	Combined (Non-GAAP) 2020	Successor 2021	Combined (Non-GAAP) 2020
Net cash provided (used) by operating activities	\$ 204	\$ (35)	\$ 660	\$ 106
Capital investments	(66)	(10)	(194)	(47)
Free cash flow	138	(45)	466	59
One-time bankruptcy related fees	1	39	6	113
Free cash flow, after special items	<u>\$ 139</u>	<u>\$ (6)</u>	<u>\$ 472</u>	<u>\$ 172</u>

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.

(\$ millions, except per BOE amounts)	Fourth Quarter		Total Year	
	Successor 2021	Combined (Non-GAAP) 2020	Successor 2021	Combined (Non-GAAP) 2020
Net income	\$ 714	\$ 3,870	\$ 625	\$ 1,871
Interest and debt expense, net	14	17	54	217
Depreciation, depletion and amortization	53	66	213	362
Income taxes	(396)	—	(396)	—
Exploration expense	1	2	7	11
Unusual, infrequent and other items ^(a)	(143)	(3,854)	290	(2,023)
Non-cash items				
Accretion expense	11	11	50	41
Stock-based compensation	4	1	14	6
Post-retirement medical and pension	2	1	3	4

Other non-cash items	—	2	—	—
Adjusted EBITDAX	\$ 260	\$ 116	\$ 860	\$ 489
Net cash provided (used) by operating activities	\$ 204	\$ (35)	\$ 660	\$ 106
Cash interest	2	15	31	95
Exploration expenditures	1	2	7	11
Working capital changes	53	134	162	277
Adjusted EBITDAX	\$ 260	\$ 116	\$ 860	\$ 489
Adjusted EBITDAX per Boe	\$ 29.22	\$ 12.25	\$ 23.65	\$ 12.09

(a) See Adjusted Net Income (Loss) reconciliation.

DISCRETIONARY CASH FLOW

We define discretionary cash flow as the cash available after distributions to noncontrolling interest holders, cash interest and asset retirement obligation and idle well testing, excluding the effect of working capital changes but before our internal capital investment. Management uses discretionary cash flow as a measure of the availability of cash to reduce debt or fund investments.

	Fourth Quarter		Total Year	
	Successor	Combined (Non-GAAP)	Successor	Combined (Non-GAAP)
(\$ millions)	2021	2020	2021	2020
Adjusted EBITDAX	\$ 260	\$ 116	\$ 860	\$ 489
Cash interest	(2)	(15)	(31)	(95)
Distributions paid to noncontrolling interest holders:				
BSP	—	(30)	(50)	(64)
Ares	—	(9)	—	(70)
Asset retirement obligations and idle well testing	(8)	(9)	(42)	(17)
Discretionary cash flow	\$ 250	\$ 53	\$ 737	\$ 243

ADJUSTED EBITDAX MARGIN

Management uses adjusted EBITDAX margin as a measure of profitability between periods and this measure is generally used by analysts for comparative purposes within the industry. Adjusted EBITDAX margin is calculated as adjusted EBITDAX divided by Revenues, excluding non-cash derivative gains and losses.

	Fourth Quarter		Total Year	
	Successor	Combined (Non-GAAP)	Successor	Combined (Non-GAAP)
(\$ millions)	2021	2020	2021	2020
Total revenues	\$ 634	\$ 301	\$ 1,889	\$ 1,559
Non-cash commodity derivative (gain) loss	(26)	127	357	157
Revenues, excluding non-cash commodity derivative gains and losses	\$ 608	\$ 428	\$ 2,246	\$ 1,716
Adjusted EBITDAX margin	43%	27%	38%	28%

ADJUSTED GENERAL & ADMINISTRATIVE EXPENSES

Management uses a measure called adjusted general and administrative (G&A) expenses to provide useful information to investors interested in comparing our costs between periods and performance to our peers.

	Fourth Quarter		Total Year	
	Successor	Combined (Non-GAAP)	Successor	Combined (Non-GAAP)
(\$ millions)	2021	2020	2021	2020

General and administrative expenses	\$ 53	\$ 59	\$ 200	\$ 252
Stock-based compensation	(4)	—	(14)	—
Incentive / retention award modification	—	—	—	(4)
Adjusted G&A expenses	<u>\$ 49</u>	<u>\$ 59</u>	<u>\$ 186</u>	<u>\$ 248</u>

OPERATING COSTS PER BOE

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. The following table presents operating costs after adjusting for the excess costs attributable to PSCs.

(\$ per BOE)	Fourth Quarter		Total Year	
	Successor 2021	Combined (Non-GAAP) 2020	Successor 2021	Combined (Non-GAAP) 2020
Energy operating costs ⁽¹⁾	\$ 5.47	\$ 4.39	\$ 5.09	\$ 3.95
Gas processing costs	0.41	0.59	0.54	0.55
Non-energy operating costs ⁽²⁾	14.57	12.44	13.76	10.95
Operating costs	\$ 20.45	\$ 17.42	\$ 19.39	\$ 15.45
Costs attributable to PSCs				
Excess energy operating costs attributable to PSCs	\$ (0.82)	\$ (0.38)	\$ (0.68)	\$ (0.32)
Excess non-energy operating costs attributable to PSCs	(1.31)	(0.75)	(1.15)	(0.57)
Excess costs attributable to PSCs	\$ (2.13)	\$ (1.13)	\$ (1.83)	\$ (0.89)
Energy operating costs, excluding effect of PSCs ⁽¹⁾	\$ 4.65	\$ 4.01	\$ 4.41	\$ 3.63
Gas processing costs, excluding effect of PSCs	0.41	0.59	0.54	0.55
Non-energy operating costs, excluding effect of PSCs ⁽²⁾	13.26	11.69	12.61	10.38
Operating costs, excluding effects of PSCs	\$ 18.32	\$ 16.29	\$ 17.56	\$ 14.56

(1) Energy operating costs consist of purchases of natural gas to generate electricity, purchased electricity and internal costs to produce electricity used in our operations.

(2) Non-energy operating costs equal total operating costs less energy and gas processing costs. However, non-energy operating costs include the costs of purchasing natural gas used to generate steam for our steamfloods.

Attachment 3

PRODUCTION STATISTICS

Net	Fourth Quarter			
	Successor 2021	Successor 2020	Predecessor 2020	Combined 2020
Oil, NGLs and Natural Gas Production Per Day				
Oil (MBbl/d)				
San Joaquin Basin	40	38	38	38
Los Angeles Basin	18	23	23	23
Ventura Basin	1	2	2	2
Total	<u>59</u>	<u>63</u>	<u>63</u>	<u>63</u>
NGLs (MBbl/d)				
San Joaquin Basin	12	12	13	13
Total	<u>12</u>	<u>12</u>	<u>13</u>	<u>13</u>
Natural Gas (MMcf/d)				
San Joaquin Basin	131	138	139	138
Los Angeles Basin	1	1	1	2
Ventura Basin	2	3	3	3
Sacramento Basin	19	23	19	20
Total	<u>153</u>	<u>165</u>	<u>162</u>	<u>163</u>

Total Production (MBoe/d)	97	103	103	103
Fourth Quarter				
Gross Operated and Net Non-Operated Oil, NGLs and Natural Gas Production Per Day	Successor 2021	Successor 2020	Predecessor 2020	Combined 2020
Oil (MBbl/d)				
San Joaquin Basin	45	44	45	45
Los Angeles Basin	26	28	27	28
Ventura Basin	1	3	3	2
Total	72	75	75	75
NGLs (MBbl/d)				
San Joaquin Basin	13	13	14	13
Total	13	13	14	13
Natural Gas (MMcf/d)				
San Joaquin Basin	138	148	149	148
Los Angeles Basin	7	8	8	8
Ventura Basin	2	3	4	4
Sacramento Basin	24	26	24	25
Total	171	185	185	185
Total Production (MBoe/d)	114	119	119	119

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 (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.

PRODUCTION STATISTICS				
Total Year				
Net	Successor	Successor	Predecessor	Combined
Oil, NGLs and Natural Gas Production Per Day	2021	2020	2020	2020
Oil (MBbl/d)				
San Joaquin Basin	39	38	42	42
Los Angeles Basin	19	23	25	24
Ventura Basin	2	2	3	3
Total	60	63	70	69
NGLs (MBbl/d)				
San Joaquin Basin	13	12	13	13
Total	13	12	13	13
Natural Gas (MMcf/d)				
San Joaquin Basin	135	138	147	145
Los Angeles Basin	1	1	2	2
Ventura Basin	4	3	4	4
Sacramento Basin	19	23	21	21
Total	159	165	174	172
Total Production (MBoe/d)	100	103	112	111
Total Year				

Gross Operated and Net Non-Operated Oil, NGLs and Natural Gas Production Per Day	Successor 2021	Successor 2020	Predecessor 2020	Combined 2020
Oil (MBbl/d)				
San Joaquin Basin	45	44	49	48
Los Angeles Basin	27	28	30	29
Ventura Basin	2	3	3	3
Total	74	75	82	80
NGLs (MBbl/d)				
San Joaquin Basin	13	13	14	14
Total	13	13	14	14
Natural Gas (MMcf/d)				
San Joaquin Basin	142	148	157	155
Los Angeles Basin	8	8	9	9
Ventura Basin	4	3	4	4
Sacramento Basin	24	26	27	26
Total	178	185	197	194
Total Production (MBoe/d)	117	119	129	127

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 (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.

Attachment 4

PRICE STATISTICS

	Fourth Quarter			
	Successor 2021	Successor 2020	Predecessor 2020	Combined 2020
Oil (\$ per Bbl)				
Realized price with derivative settlements	\$ 61.00	\$ 45.37	\$ 42.45	\$ 44.39
Realized price without derivative settlements	\$ 78.99	\$ 45.65	\$ 40.59	\$ 43.94
NGLs (\$/Bbl)	\$ 67.61	\$ 38.00	\$ 30.57	\$ 35.45
Natural gas (\$/Mcf)	\$ 5.94	\$ 3.21	\$ 2.68	\$ 3.03
Index Prices				
Brent oil (\$/Bbl)	\$ 79.80	\$ 47.10	\$ 41.52	\$ 45.24
WTI oil (\$/Bbl)	\$ 77.19	\$ 44.21	\$ 39.55	\$ 42.66
NYMEX gas (\$/MMBtu)	\$ 5.27	\$ 2.86	\$ 2.28	\$ 2.66
Realized Prices as Percentage of Index Prices				
Oil with derivative settlements as a percentage of Brent	76%	96%	102%	98%
Oil without derivative settlements as a percentage of Brent	99%	97%	98%	97%
Oil with derivative settlements as a percentage of WTI	79%	103%	107%	104%
Oil without derivative settlements as a percentage of WTI	102%	103%	103%	103%
NGLs as a percentage of Brent	85%	81%	74%	78%
NGLs as a percentage of WTI	88%	86%	77%	83%
Natural gas as a percentage of NYMEX	113%	112%	118%	114%

	Total Year			
	Successor 2021	Successor 2020	Predecessor 2020	Combined 2020
Oil (\$ per Bbl)				
Realized price with derivative settlements	\$ 56.05	\$ 45.37	\$ 43.19	\$ 43.53
Realized price without derivative settlements	\$ 70.43	\$ 45.65	\$ 41.21	\$ 41.89
 NGLs (\$/Bbl)	 \$ 53.62	 \$ 38.00	 \$ 25.70	 \$ 27.63
 Natural gas (\$/Mcf)	 \$ 4.22	 \$ 3.21	 \$ 2.11	 \$ 2.28
 Index Prices				
Brent oil (\$/Bbl)	\$ 70.79	\$ 47.10	\$ 42.43	\$ 43.21
WTI oil (\$/Bbl)	\$ 67.91	\$ 44.21	\$ 38.44	\$ 39.40
NYMEX gas (\$/MMBtu)	\$ 3.61	\$ 2.86	\$ 1.95	\$ 2.10
 Realized Prices as Percentage of Index Prices				
Oil with derivative settlements as a percentage of Brent	79%	96%	102%	101%
Oil without derivative settlements as a percentage of Brent	99%	97%	97%	97%
 Oil with derivative settlements as a percentage of WTI	 83%	 103%	 112%	 110%
Oil without derivative settlements as a percentage of WTI	104%	103%	107%	106%
 NGLs as a percentage of Brent	 76%	 81%	 61%	 64%
NGLs as a percentage of WTI	79%	86%	67%	70%
 Natural gas as a percentage of NYMEX	 117%	 112%	 108%	 109%

Attachment 5

FOURTH QUARTER 2021 DRILLING ACTIVITY

Wells Drilled	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Development Wells					
Primary	1	—	—	—	1
Waterflood	18	8	—	—	26
Steamflood	12	—	—	—	12
Total ⁽¹⁾	31	8	—	—	39

TOTAL YEAR 2021 DRILLING ACTIVITY

Wells Drilled	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Development Wells					
Primary	3	—	—	—	3
Waterflood	67	9	—	—	76
Steamflood	25	—	—	—	25
Total ⁽¹⁾	95	9	—	—	104

(1) Includes steam injectors and drilled but uncompleted wells, which are not included in the SEC definition of wells drilled.

Attachment 6

OIL HEDGES AS OF DECEMBER 31, 2021

	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
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Sold Calls

Barrels per day	35,347	35,343	34,380	25,167	14,790
Weighted-average Brent price per barrel	\$60.37	\$60.63	\$60.76	\$57.82	\$58.01

Swaps

Barrels per day	12,369	10,669	10,476	17,263	12,937
Weighted-average Brent price per barrel	\$54.38	\$54.12	\$53.97	\$58.79	\$59.08

Net Purchased Puts ⁽¹⁾

Barrels per day	35,347	35,343	34,380	25,167	14,790
Weighted-average Brent price per barrel	\$53.32	\$54.69	\$55.95	\$57.22	\$40.00

Sold Puts

Barrels per day	6,869	—	4,000	1,348	—
Weighted-average Brent price per barrel	\$32.00	—	\$32.00	\$32.00	—

(1) Purchased and sold puts with the same strike price have been netted together.

Attachment 7

TOTAL CRC GUIDANCE¹	E&P 2022E	CMB 2022E	2022E
Net Total Production (Mboe/d)	93 - 90		93 - 90
Net Oil Production (Mbbbl/d)	60 - 56		60 - 56
Operating Costs (\$ millions)	\$640 - \$670		\$640 - \$670
CMB Expenses ² (\$ millions)		\$30 - \$40	\$30 - \$40
Adjusted General and Administrative Expenses (\$ millions)	\$155 - \$175	\$10 - \$15	\$165 - \$190
Capital (\$ millions)	\$300 - \$335	\$30 - \$40	\$330 - \$375
Adjusted EBITDAX (\$ millions)	\$800 - \$940	(\$40) - (\$55)	\$745 - \$900
Free Cash Flow ³ (\$ millions)	\$350 - \$450	(\$70) - (\$95)	\$255 - \$380
Cash Tax as % of Pre-Tax Income			10% - 18%

See Attachment 2 for management's disclosure of its use of these non-GAAP measures and how these measures provide useful information to investors about CRC's results of operations and financial condition. For FY 2022E guidance, management is not providing guidance on income taxes or any unusual or infrequent events at this time.

	E&P 2022E		CMB 2022E		2022 Estimated	
	Low	High	Low	High	Low	High
Net cash provided (used) by operating activities	\$ 685	\$ 750	\$ (55)	\$ (40)	\$ 630	\$ 710
Capital investments	(335)	(300)	(40)	(30)	(375)	(330)
Estimated free cash flow	\$ 350	\$ 450	\$ (95)	\$ (70)	\$ 255	\$ 380

	E&P 2022E		CMB 2022E		2022 Estimated	
(\$ millions)	Low	High	Low	High	Low	High
Net income	\$ 266	\$ 306	\$ (55)	\$ (40)	\$ 211	\$ 266
Interest and debt expense, net	48	58	—	—	48	58
Depreciation, depletion and amortization	183	224	—	—	183	224
Exploration expense	7	9	—	—	7	9
Income taxes	32	40	—	—	32	40
Unusual, infrequent and other items	199	225	—	—	199	225
Other non-cash items						
Accretion expense	50	61	—	—	50	61
Stock-based compensation	13	15	—	—	13	15

Post-retirement medical and pension	2	2	—	—	2	2
Estimated adjusted EBITDAX	\$ 800	\$ 940	\$ (55)	\$ (40)	\$ 745	\$ 900

Net cash provided (used) by operating activities	\$ 685	\$ 750	\$ (55)	\$ (40)	\$ 630	\$ 710
Cash interest	44	54	—	—	44	54
Cash income taxes	32	40	—	—	32	40
Exploration expenditures	7	9	—	—	7	9
Working capital changes	32	87	—	—	32	87
Estimated adjusted EBITDAX	\$ 800	\$ 940	\$ (55)	\$ (40)	\$ 745	\$ 900

	E&P 2022E		CMB 2022E		2022 Estimated	
(\$ millions)	Low	High	Low	High	Low	High
General and administrative expenses	\$ 170	\$ 185	\$ 10	\$ 15	\$ 180	\$ 200
Stock-based compensation	(15)	(10)	—	—	(15)	(10)
Adjusted general and administrative expenses	\$ 155	\$ 175	\$ 10	\$ 15	\$ 165	\$ 190

¹ Current guidance assumes a 2022 price of \$82.50 per barrel of oil, NGL realizations consistent with prior years and NYMEX gas of \$4.00 per mcf. CRC's share of production under PSCs decreases when commodity prices rise and increases when prices fall.

² CMB expenses include start-up expenditures.

³ 2022E E&P Free Cash Flow includes settled ARO liabilities in the range of \$60 million - \$64 million.

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Source: California Resources Corporation