"Low Carbon Intensity Fuel for Today and Net Zero Fuel for The Future"

Third Quarter 2022 Results

November 3, 2022

Presenters

- **Mac McFarland** — *President & Chief Executive Officer*
- **Francisco Leon** — *EVP & Chief Financial Officer*

Forward Looking / Cautionary Statements – Certain Terms

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

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

- fluctuations in commodity prices and the potential for sustained low oil, natural gas and natural gas liquids prices;
- equipment, service or labor price inflation or unavailability;
- legislative or regulatory changes, including those related to (i) the location, drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, (ii) the management of energy, water, land, greenhouse gases (GHGs) or other emissions, (iii) the protection of health, safety and the environment, (iv) the availability of and our ability to claim and utilize tax credits or other incentives, or (v) the transportation, marketing and sale of our products and CO_2;
- availability or timing of, or conditions imposed on, permits and approvals necessary for drilling or development activities and carbon management projects;
- changes in business strategy and our 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 cashflows and the inability to replace reserves;
- Our ability to achieve similar financial or operational results in the future as in prior periods, including with respect to free cash flow
- the recoverability of resources and unexpected geologic conditions;
- our ability to successfully execute on the construction and other aspects of the infrastructure projects and enter into third party contracts on contemplated terms;
- our ability to realize the benefits contemplated by the business strategies and initiatives related to energy transition, including carbon capture and storage projects and other renewable energy efforts;
- our ability to successfully identify, develop and finance carbon capture and storage projects and other renewable energy efforts, including those in connection with the Carbon TerraVault JV;
- global geopolitical, socio-demographic and economic trends and technological innovations;
- changes in our dividend policy and our ability to declare future dividends under our debt agreements;
- changes in our share repurchase program and our capacity to repurchase shares under our debt agreements;
- production-sharing contracts' effects on production and operating costs;
- limitations on our financial flexibility due to existing and future debt;
- insufficient cash flow to fund our capital plan and other planned investments, stock repurchases and dividends;
- insufficient capital or lack of liquidity in the 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 achieve expected synergies from joint ventures and acquisitions;
- our ability to utilize our net operating loss carryforwards to reduce our income tax obligations;
- our ability to successfully gather and verify data regarding emissions, our environmental impacts and other initiatives;
- the compliance of various third parties with our policies and procedures and legal requirements as well as contracts we enter into in connection with our climate-related initiatives;
- the effect of our stock price on costs associated with incentive compensation;
- changes in the intensity of competition in the oil and gas industry;
- effects of hedging transactions;
- 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.

We caution you not to place undue reliance on forward-looking statements contained in this document, which speak only as of the filing date, and we undertake no obligation to update this information. This document may also contain information from third party sources. This data may involve a number of assumptions and limitations, and we have not independently verified them and do not warrant the accuracy or completeness of such third-party information. Nothing herein is intended to imply or create a legal partnership between Brookfield Global Transition Fund, California Resources Corporation, Carbon TerraVault Holdings, LLC or any of their respective subsidiaries and affiliates.

Glossary

Term	Definition
BMT	Billion Metric Tons
CARB	California Air Resources Board
CCS	Carbon Capture and Storage
CCS+	Carbon Capture and Storage + EOR
CGP	Cryogenic Gas Plant
CI	Carbon Intensity
CMB	Carbon Management Business
CO_2	Carbon Dioxide
CTV	Carbon TerraVault (a subsidiary of CRC)
DAC	Direct Air Capture
D&C	Drilling and Completions
E&P	Exploration and Production
EIR	Environmental Impact Report
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency

Term	Definition
ESG	Environmental, Social and Governance
FCF	Free Cash Flow
FEED	Front End Engineering and Design
FID	Final Investment Decision
GHG	Greenhouse Gas
LCFS	Low Carbon Fuel Standard
MMT	Million Metric Tons
MMTPA	Million Metric Tons Per Annum
MRV	Monitoring, Reporting and Verification Plan
MT	Metric Tons
MTPA	Metric Tons Per Annum
NP15	North of Path 15
ROFL	Right of First Look
RTC	Round-the-Clock
SRP	Share Repurchase Program
WI	Working Interest

Continuing to Define CRC's Transition to a Different Kind of Energy Company

Delivering Consistent & Predictable Free Cash Flow

- Generated $644MM of Adj. EBITDAX[1] and $272MM of Free Cash Flow[1] in 2022
- Monetized $79MM in divestitures YTD
- Optimizing asset portfolio, activity and evaluating real estate alternatives for Huntington Beach

Disciplined Capital Allocation Underpins Robust Shareholder Return Strategy

- Raising fixed dividend by 66% and repurchased $276MM of stock in 2022[2]
- On track for ~$1B in shareholder returns by the end of 2023[3]
- Increasing Share Repurchase Program by $200MM and extending it through December 31, 2023

Advancing & Accelerating Carbon Management Business

- Collaborating with industry players to advance the development of energy transition technologies
- Expanding CCS total addressable market through discussions with a variety of emissions sources including greenfield projects (e.g., renewable fuels, DAC and hydrogen)
- Presented 3 reservoirs as farm-downs to the Carbon TerraVault JV with Brookfield

A DIFFERENT KIND OF ENERGY COMPANY

(1) Represents a non-GAAP measure. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. (2) Includes repurchases from Jan. 1, 2022 to October 31, 2022. (3) Assumes cumulative repurchases utilizing the entirety of the share repurchase program and cumulative dividends through year end 2023, which are subject to Board approval.

Third Quarter 2022 Operational & Financial Results

CALIFORNIA RESOURCES CORPORATION COMPANY | CARBON TERRAVAULT

3Q22 Highlights

92 MBOE/D
3Q22 NET PRODUCTION

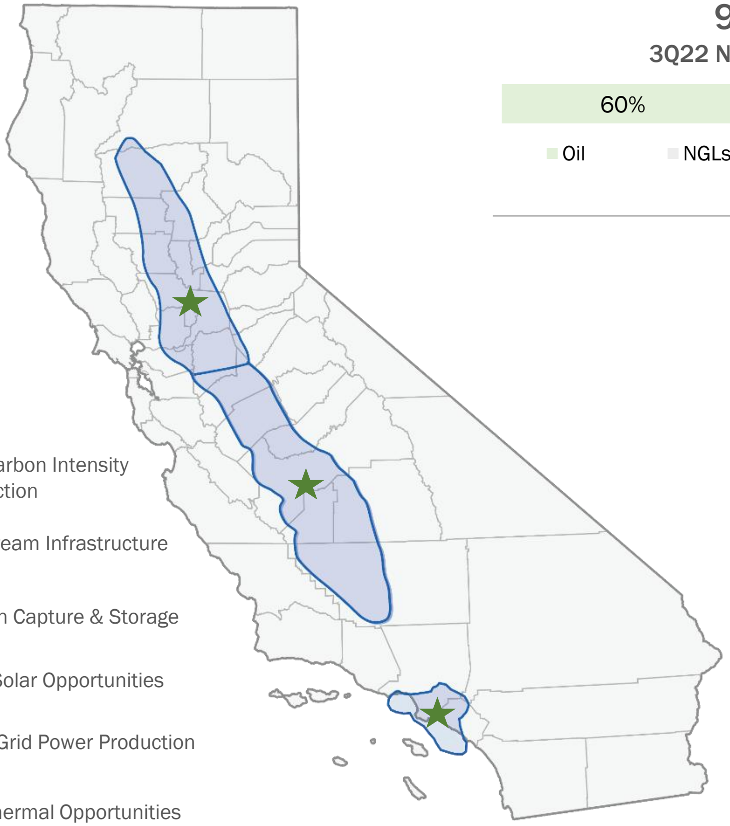
Oil	NGLs	Gas
60%	13%	27%

$235MM
3Q22 OPERATING CASH FLOW

Capex	Free Cash Flow[1]
$107	$128

~$286MM
TOTAL SHAREHOLDER RETURN[2]

Dividend	SRP
$39	$247



- Low Carbon Intensity Production
- Midstream Infrastructure
- Carbon Capture & Storage
- BTM Solar Opportunities
- FTM/Grid Power Production
- Geothermal Opportunities

Increased the RBL Commitment by $50MM in 3Q22 and $110MM YTD
Reaffirmed Borrowing Base

Published 2021 Sustainability Report

Favorable Ruling in Kern County EIR Litigation

Testing HB Real Estate Market and Secondary Use

Redirecting Drilling Activity to Huntington Beach
Preparing Storage Reservoirs for Future Carbon TerraVault Opportunities

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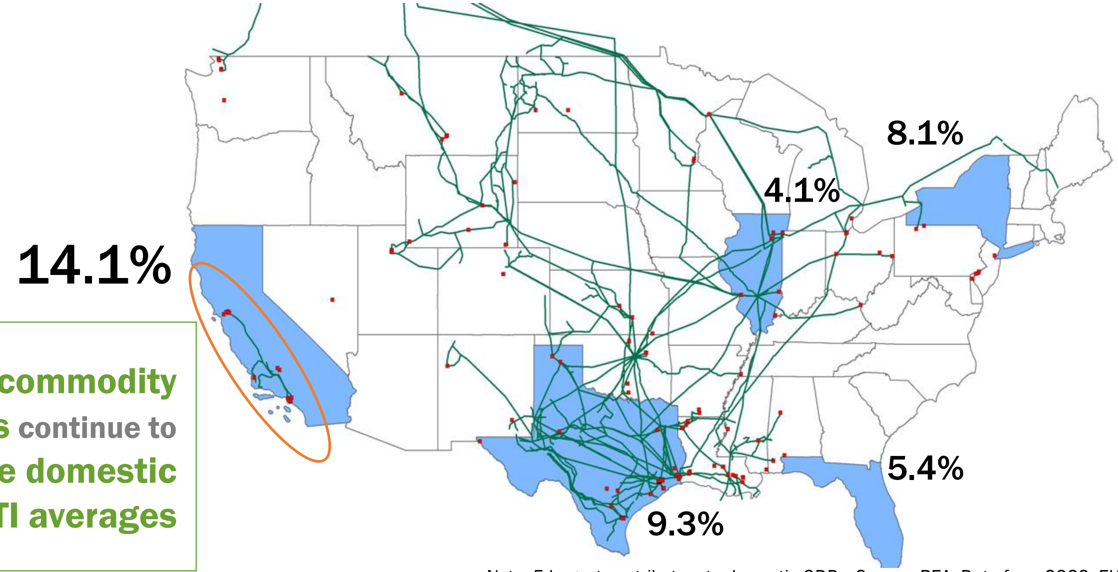
Strong Price Realizations in CA's Unique Market Dynamics

- Crude: CRC's 3Q22 physical crude realizations moved lower Q/Q in tandem with U.S. and global crude prices. Realizations came under limited pressure as an unexpected outage on Plains All-American Pipeline Line 2000 required shippers to remarket and / or modify logistics related to barrels previously slated for pipeline delivery to Los Angeles. Refining margins across California, nonetheless, continued to be supportive to local physical crude postings relative to Brent.
- NGLs: 3Q22 NGL realizations declined from 2Q22, in-line with seasonal and expectations. The broader NGL market saw values decline as a percentage of Brent in 3Q22 as increased production met with slack seasonal demand across North America.
- Natural Gas: California natural gas prices remained strong both Q/Q and Y/Y. The benchmark SoCal Border Index for 3Q22 averaged $9.10/MCF (vs $6.98/ in 2Q22 & $4.60/ in 3Q21) which is the highest quarterly / 3rd-quarter average since 2008. Prices were particularly strong in September as demand for natural gas to generate electricity surged within California and across the U.S.

CRC's commodity realizations continue to trend above domestic WTI averages

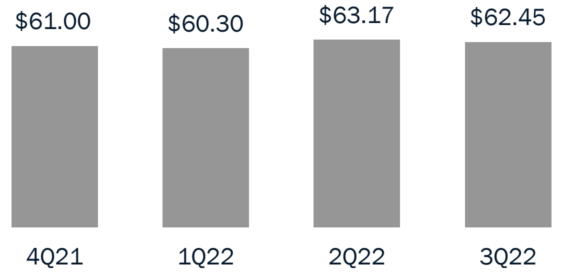
CALIFORNIA IS AN ENERGY ISLAND AND THE LARGEST U.S. GDP CONTRIBUTOR

(amounts shown as % of U.S. domestic GDP)



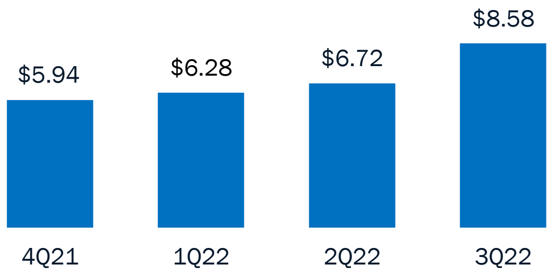
Note: 5 largest contributors to domestic GDP. Source: BEA, Data from 2Q22; EIA

Oil w/ Hedges ($/BBL)



NGLs ($/BBL)

Natural Gas ($/MCF)

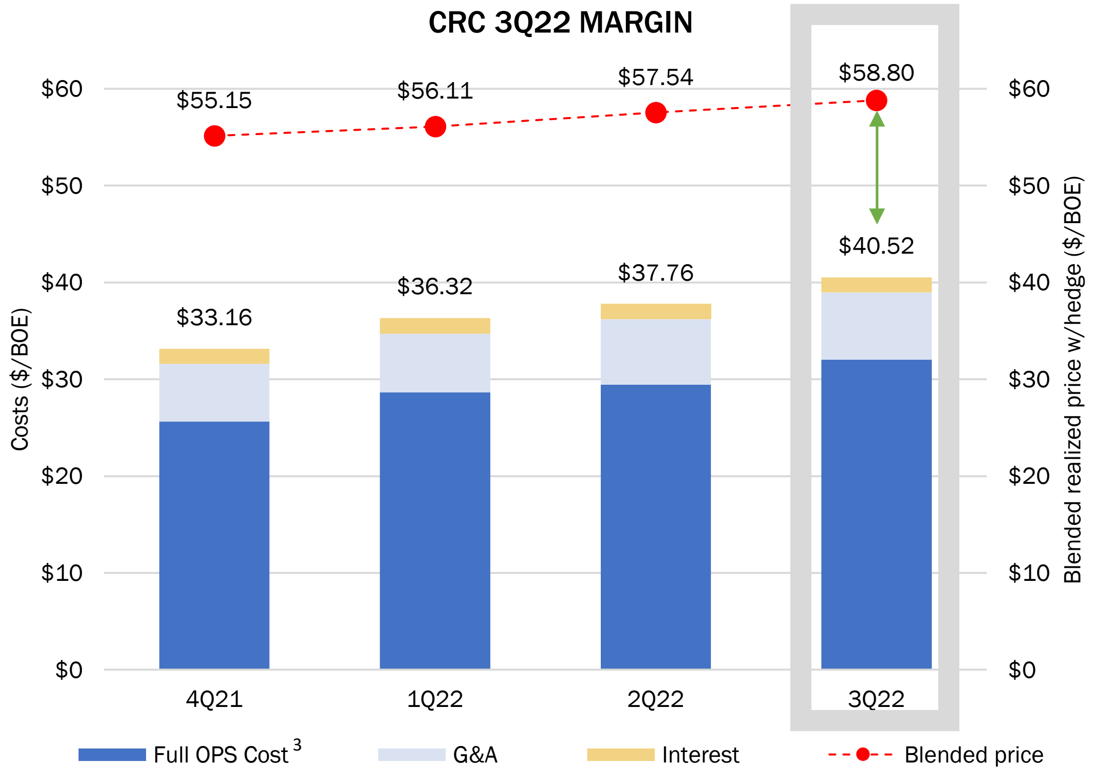


	Oil 4Q21	Oil 1Q22	Oil 2Q22	Oil 3Q22	NGLs 4Q21	NGLs 1Q22	NGLs 2Q22	NGLs 3Q22	Gas 4Q21	Gas 1Q22	Gas 2Q22	Gas 3Q22
Average Benchmark Prices[1]	$79.80	$97.38	$111.79	$97.81	$79.80	$97.38	$111.79	$97.81	$5.27	$4.19	$6.62	$7.85
% of Benchmark[1]	99%	99%	100%	100%	85%	81%	61%	59%	113%	150%	103%	112%
Hedge Settlements	($17.99)	($35.83)	($49.15)	($35.51)	–	–	–	–	–	–	($0.13)	($0.22)
Average Realized Prices[2]	$61.00	$60.30	$63.17	$62.45	$67.61	$78.63	$68.29	$57.68	$5.94	$6.28	$6.72	$8.58

(1) Benchmark prices are based on Brent for oil and NGLs, and NYMEX average daily price for natural gas. (2) Average realized prices include hedges on oil and natural gas.

Focus on Maintaining Margin to Offset Rising Energy Costs and Inflation

Natural gas markets drove cost increases primarily in electricity generation and, to a lesser extent, steamflood operations, which were more than offset by increased natural gas revenues



	4Q21	1Q22	2Q22	3Q22
Energy operating costs[1] ($/BOE)	$8.04	$9.16	$9.33	$10.96
Gas processing costs ($/BOE)	$0.41	$0.56	$0.54	$0.49
Non-energy operating costs[1] ($/BOE)	$12.00	$13.15	$13.05	$13.82
Operating costs ($/BOE)	**$20.45**	**$22.87**	**$22.92**	**$25.27**
Costs attributable to PSC-type contracts[2] ($/BOE)	($2.13)	($2.30)	($2.58)	($2.16)
Operating costs excluding effects of PSC-type contracts[2] ($/BOE)	**$18.32**	**$20.57**	**$20.34**	**$23.11**
Transportation ($/BOE)	$1.57	$1.51	$1.45	$1.54
Taxes other than on income ($/BOE)	$3.61	$4.28	$5.07	$5.20
G&A ($/BOE)	$5.96	$6.03	$6.76	$6.97
E&P, Corp. and Other G&A ($/BOE)	$5.96	$5.90	$6.28	$6.38
CMB G&A ($/BOE)	-	$0.13	$0.48	$0.59
Adj. G&A[2] ($/BOE)	$5.51	$5.53	$6.15	$6.26
E&P, Corp. and Other Adj. G&A[2] ($/BOE)	$5.51	$5.40	$5.67	$5.67
CMB Adj. G&A[2] ($/BOE)	-	$0.13	$0.48	$0.59
Interest and debt expense, net ($/BOE)	$1.57	$1.63	$1.57	$1.54

(1) Energy operating costs consist of purchases of natural gas used to generate electricity, purchased electricity and internal costs to produce electricity used in our operations. Energy operating costs also includes costs related to natural gas purchased from third parties that is used in our steamflood operations. Non-energy operating costs equal total operating costs less energy operating costs and gas processing costs. (2) Represent non-GAAP measures. For all historical non-GAAP financial measures, please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. (3) Full OPS cost includes operating costs plus transportation costs, plus taxes other than on income.

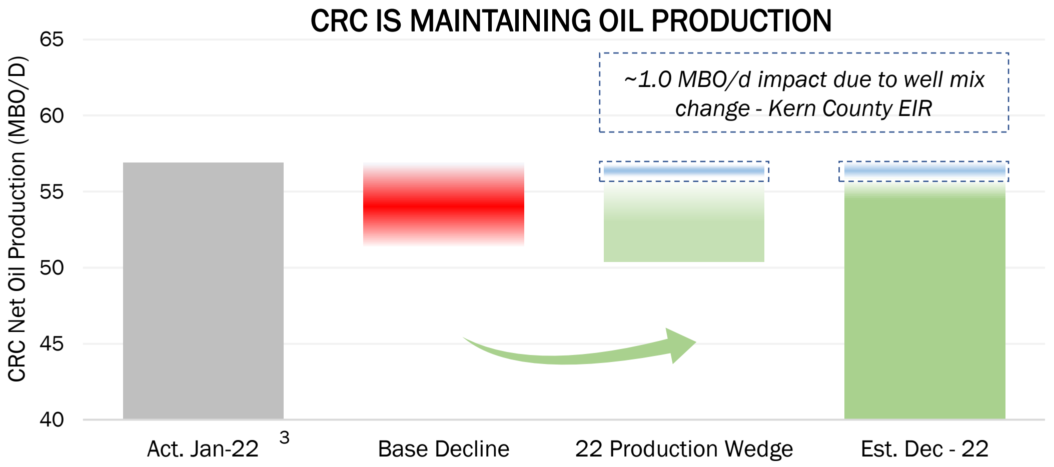
Quickly Adjusting Asset Portfolio to Address California Dynamics

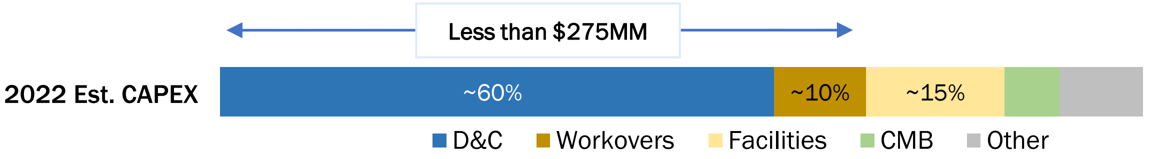
OPERATIONAL UPDATE:

- In 3Q22, ran 5 out of 7 active drilling rigs[1] in California and 33 maintenance rigs; continuing to deliver strong operational results
- Continuing to implement several inflation and operational measures to further offset cost increases (ex: waste gas generator, steam cuts and others)
- Kern County EIR litigation and the subsequent change in operational cadence/well mix negatively impacts 2022 total oil production by 1.0 MBO/D at exit
- CRC entered 4Q22 with four drilling rigs. We plan to run 3 rigs for the remainder of the year in our Elk Hills, Buena Vista, Wilmington and Huntington Beach fields as we reposition for our 2023 program.
- After adjusting for asset divestitures and change in well mix, expecting to exit 2022 with total net production at ~94 MBOE/D[2]

Favorable Ruling in Kern County EIR Litigation

CRC IS MAINTAINING OIL PRODUCTION

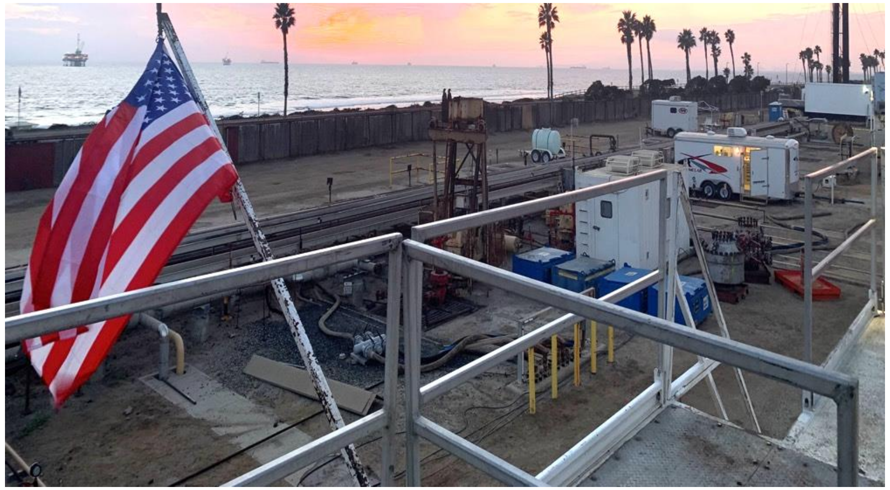




MOVING ONE RIG FROM SJB TO HUNTINGTON BEACH:

- Quick and impactful program taking advantage of existing permits
- Planning to drill 6 to 8 high confidence wells in Jones and TM Sand formations
- Expecting to plug and abandon ~29 existing wells after program's completion and begin site clean up in 2023
- HB program doesn't affect 2022 D&C capital needs but is expected to yield at its peak 1 MBO/D of low carbon intensity oil
- Exploring the divestiture of a small parcel of land to test the real estate value in Huntington Beach area

Huntington Beach	
Wells Drilled	6 - 8
Well Cost ($MM)	$1.5 - $3.0
TMD (ft.)	~6,500
Peak IP[4] (BOE/D)	155
Oil %	97%



(1) Source: Baker Hughes Rig Count for the quarter ended September 30, 2022 as of October 21, 2022. (2) 2022 entry total net production of 96.9 MBOE/D after excluding 2.4 MBO/D and 1.0 MBO/D impacts due to asset divestitures and change in well mix, respectively. Est. annual decline rate of ~ 10% - 15% range. (3) Adjusted for 2022 divestitures of approximately 2.4 MBO/D. (4) Peak IP rate defined as highest production achieved during first 90 days of production.

Reaffirmed 2022E Corporate Adj. EBITDAX[1] and FCF[1] Guidance Based on Commodity Outlook

CRC GUIDANCE[2]	4Q 2022: E&P, Corp. & Other	4Q 2022: CMB	4Q 22E	FY 2022: E&P, Corp. & Other	FY 2022: CMB	FY22E
Total Production[3] (MBOE/D)	93 – 91	—	93 – 91	94 – 91	—	94 – 91
Oil Production[3] (MBO/D)	56 – 54	—	56 – 54	58 – 53	—	58 – 53
Operating Costs ($MM)	$185 - $195	—	$185 - $195	$760 – $790	—	$760 – $790
Carbon Management Expenses[4] ($MM)	—	$3 - $8	$3 - $8	—	$10 - $20	$10 - $20
Adj. G&A[1] ($MM)	$50 - $55	$2 - $6	$52 - $61	$185 - $195	$10 - $15	$195 – $210
Adj. EBITDAX[1] ($MM)	$210 - $240	($5) - ($14)	$196 - $235	$870 - $910	($20) - ($35)	$835 – $890
Capital ($MM)	$70 - $80	$4 - $8	$74 - $88	$360 - $370	$20 - $30	$380 – $400
Free Cash Flow[1] ($MM)	$85 - $100	($9) - ($22)	$63 - $91	$390 - $410	($40) – ($65)	$325 – $370

2022E Guidance Notes:

2022 Commodity Outlook	▪ CRC 2022 commodity outlook has changed from $103.42/bbl for Brent and $5.62/mcf for NYMEX to $99.75/bbl for Brent and $6.47/mcf for NYMEX
Kern County EIR Litigation	▪ Favorable ruling in Kern County EIR Litigation
Inflation & Natural Gas price increase	▪ 2022 CRC's non–energy operating costs continued to reflect higher than expected rise in costs for materials, well services, equipment needs and maintenance with an expected increase of ~$21MM ▪ CRC's energy operating costs impacted by a higher-than-expected increase in natural gas pricing in the amount of ~$15MM, but CRC is net long in natural gas

(1) Represents non-GAAP measures. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. Reconciliations of 2022E non–GAAP measures to their nearest GAAP equivalent can be found on slides 33 to 37. (2) Current guidance assumes a 2022 Brent price of $99.75 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $6.47 per mcf. CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. (3) 2022E production ranges subject to PSC effects and account for the Ventura and Lost Hills divestitures as well as CGP1 scheduled maintenance. (4) CMB expenses include start-up expenditures.

Trends We See for 2023

Preliminary 2023 Details

- Forecasting a higher facilities/CMB capital deployment to meet regulatory requirements in order to prepare reservoirs for Carbon TerraVault / CO_2 Injection
- As legacy hedges[1] roll off in 2023, CRC's increased realizations are expected to offset or exceed inflation expectations of 5% - 10% YoY in operating expenses, wages and in drilling, completion & workover capital needs
- CRC D&C capital to maintain oil production is ~$300MM
- Expecting increasing income tax obligations in 2023 as net operating loss carryforwards are used
  - Federal and California cash taxes of 15% to 20% of pretax income
  - Taxes affected by commodity price and mark to market positions on legacy hedge position

Expecting to Continue to Deliver Consistent & Predictable Free Cash Flow

(1) Legacy hedges refers to hedges which were entered into at the time of our emergence from bankruptcy as a requirement of our revolving credit facility. Assumes strip pricing as of September 30, 2022.

Disciplined Capital Allocation Underpins Shareholder Returns Strategy

Disciplined Capital Allocation Underpins Robust Shareholder Return Strategy

~50% Reinvestment or Less

Large base of low decline assets provides stable base of low CI energy with moderate investment needs

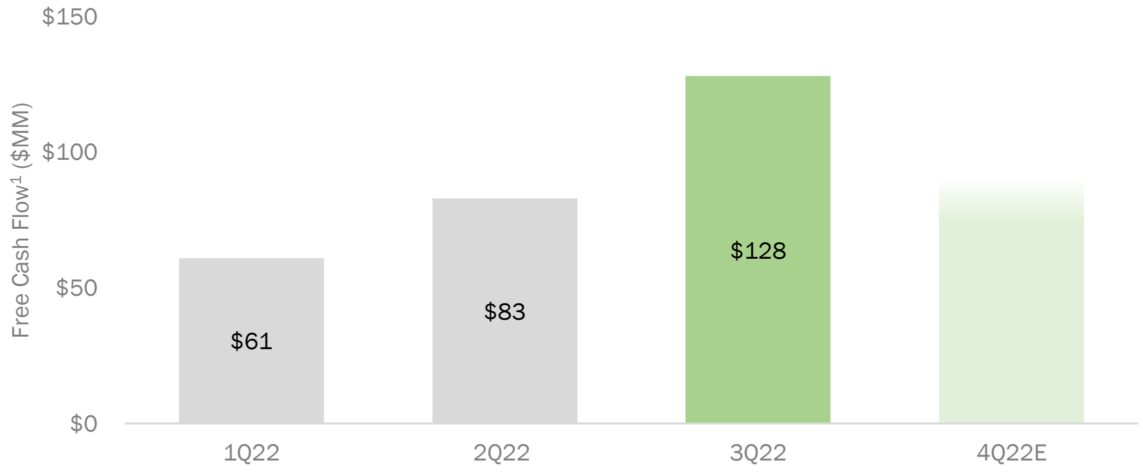
Limited CRC Capital for CMB

CMB capital costs expected to be largely funded via Carbon TerraVault JV with Brookfield

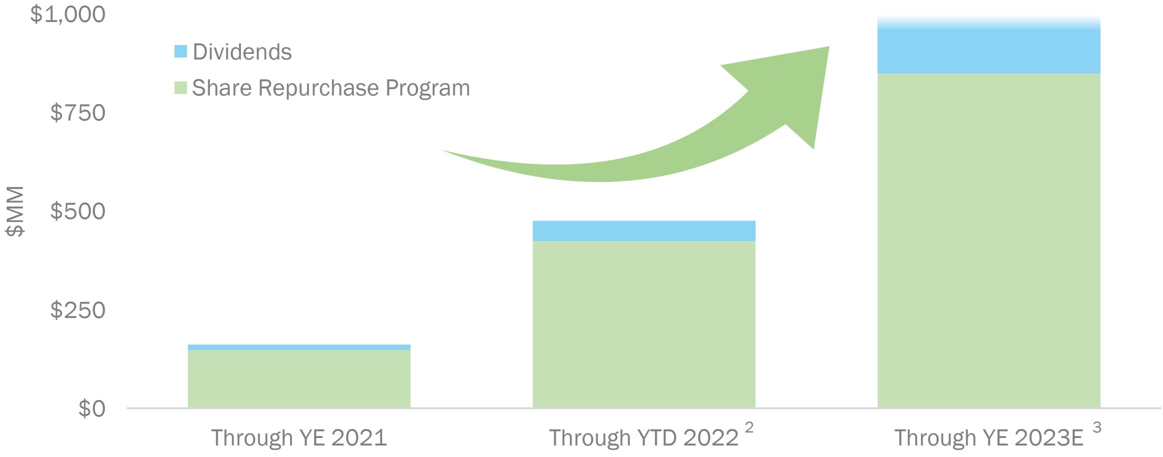
Financial Flexibility & Capital Return Capability

FCF available for accelerated shareholder returns such as Share Repurchase Program & dividends

2022 FREE CASH FLOW[1] GENERATION



EST. CUMULATIVE SHAREHOLDER RETURN BY YE23



(1) Free Cash Flow is a non-GAAP measure. For all historical non-GAAP financial measures, please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. (2) Includes cumulative repurchases from Jan. 1, 2021, to October 31, 2022, and cumulative distributed dividends for 2021 and YTD 2022 of ~$52MM. (3) Assumes cumulative repurchases utilizing the entirety of the share repurchase program and cumulative dividends through year end 2023, which are subject to Board approval and restrictions under our debt agreements.

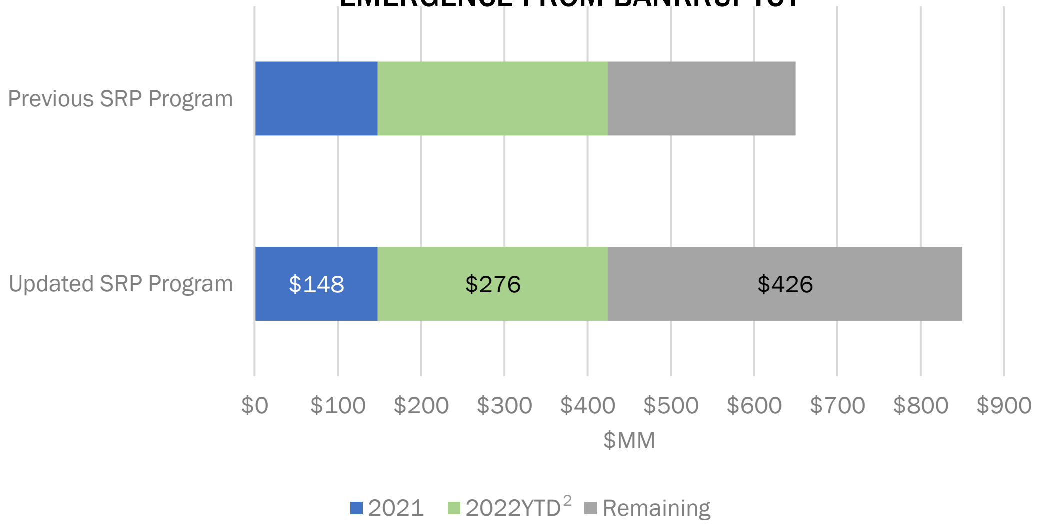
Prioritizing Shareholder Returns

31% Increase in SRP
Increasing Share Repurchase Program to $850MM and extending through December 31, 2023

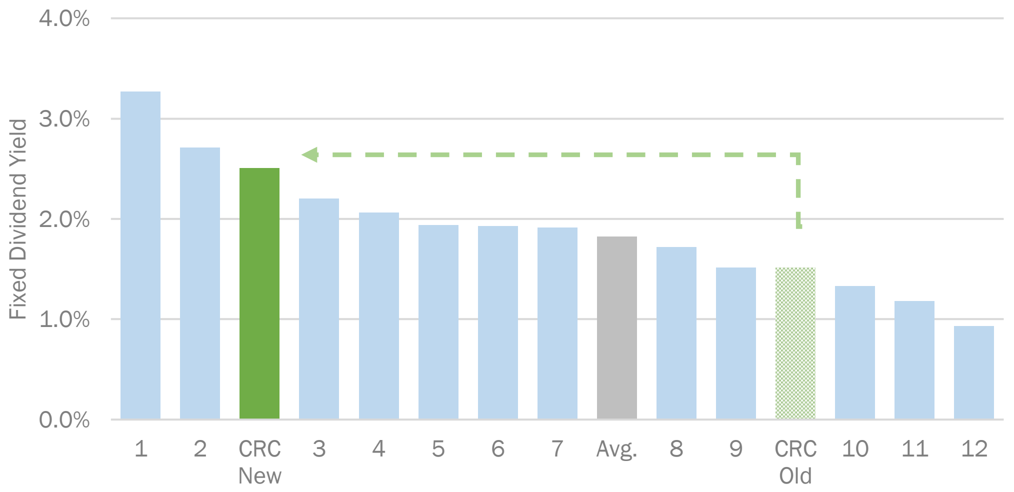
~$1B
Est. Total Dividends and Share Repurchases Through YE23[1]

66% Increase in Dividend
Raising fixed dividend to $0.2825/share per quarter

REPURCHASED ~13% OF THE SHARES THAT CRC ISSUED AT EMERGENCE FROM BANKRUPTCY[2]



NEW DIVIDEND PUTS CRC AMONGST THE TOP OF ITS PEERS[3]



(1) See slide 14 for details. (2) As of October 31, 2022. (3) Calculated as the most recent declared dividend annualized over market capitalization as of October 31, 2022. Peers include BRY, CHRD, CLR, CTRA, DVN, EOG, FANG, MRO, MTDR, MUR, PDCE, PXD and SM.

Advancing & Accelerating Carbon Management Business

Evolving with the Energy Transition

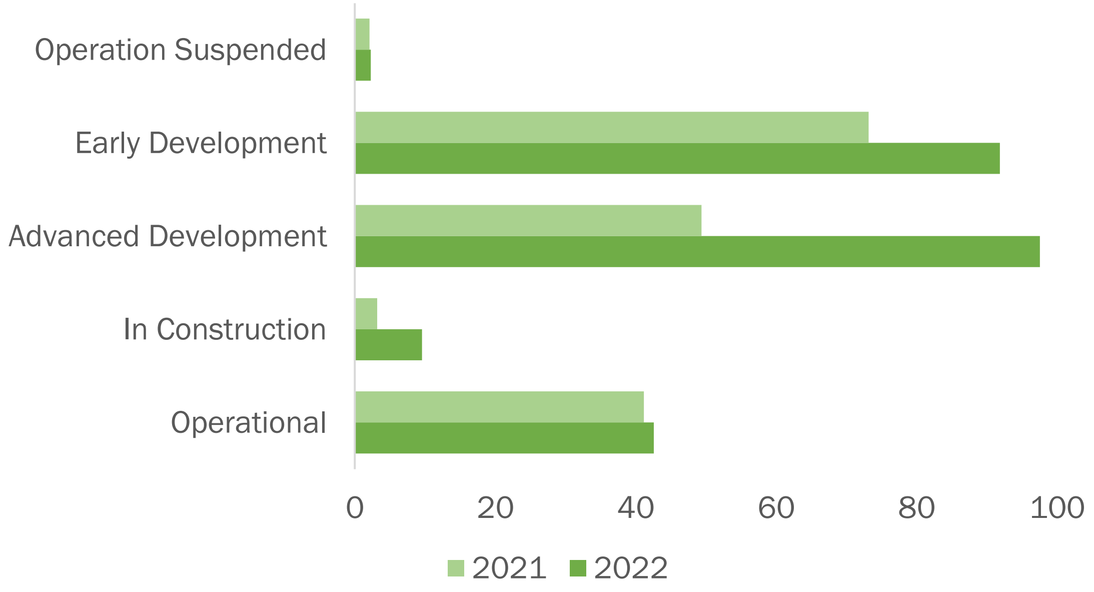
Increased Incentives Driving Energy Transition Technology

- Indications of further tightening of LCFS market.[1] CARB is expected to release its final scoping plan in 4Q (anticipated increase to a 25% - 30% 2030 target from previous 20%) with several changes to the program
- DOE announced a ~$4.9B set of funding opportunities to significantly reduce CO_2 emissions released into the atmosphere through power generation and industrial operations[2]
- The pipeline for worldwide projects to capture and store carbon emissions has grown around 44% in the past twelve months to 244 MMTPA[3]

44% Increase

In total capacity of commercial CCS projects in the pipeline over the past 12 months[1]

Commercial CCS Facilities Worldwide



Source: Global CCS Institute - Global Status of CCS 2022 report

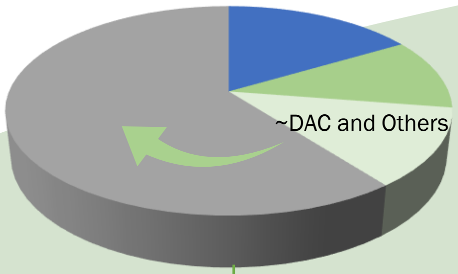
(1) Source: Internal estimates. (2) Source: DOE (https://www.energy.gov/articles/biden-harris-administration-announces-49-billion-deploy-infrastructure-necessary-manage). (3) Source: Global CCS Institute - Global Status of CCS 2021 report (https://status22.globalccsinstitute.com/2022-status-report/ambition-to-action/).

Expanding the Pie With the New Energy Economy

Carbon TerraVault

Positioned to Be California's Premier Carbon Management Provider

Future Evolution of CA's Emissions[2]

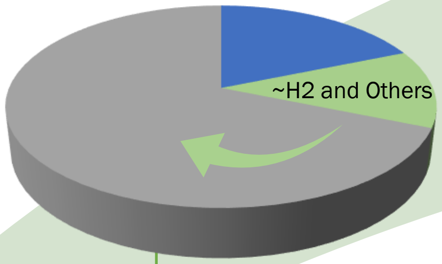


~150 - 210

MMTPA or more

California's Potential Addressable CCS Market Size by 2045[5]

Expanded Evolution of CA's Emissions[2]



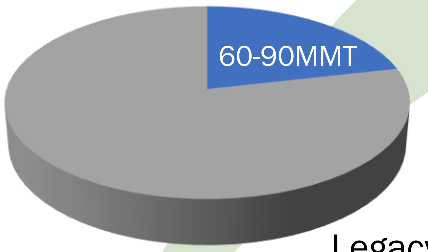
Evolving Technologies

Direct Carbon Dioxide Removal

Ex: - Direct Air Capture (DAC) – 66MMTPA by 2045[3]

- Other Technologies in Development

Current Legacy CA Annual Emissions[1]



Transitional Fuels/ Replacement Sources

Indirect Decarbonization of Non-Stationary Point Source Emissions Through Transition Fuel Technology Generation

Ex: - Ethanol

- Hydrogen - Est. CA's CO_2 emissions from Hydrogen production in the range of ~28 to 55 MMTPA[4] by 2045[3]
- Renewable Diesel
- Biodiesel

Legacy Emissions

Direct Decarbonization of Stationary Point Source Emissions - 60 to 90 MMTPA

Ex: - Refiners

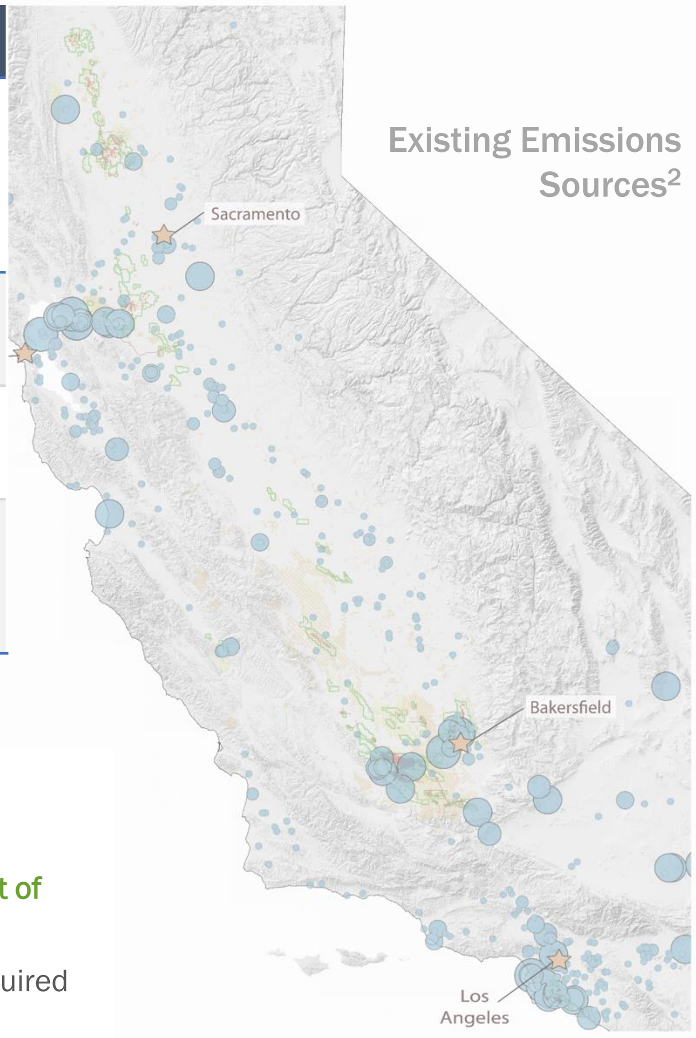
- Industrials/Manufacturing (Cement)
- Natural Gas Fired Power Plants

■ Addressable with CCS Today
■ Addressable Indirectly
■ Addressable In The Near Future
■ Other

Note: Graphic intended for illustrative purposes only. (1) Source: Energy Futures Initiative and Stanford University. "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions." October 2020; EPA; NATCARB; CARB; Internal estimates. (2) Includes Brownfield and Greenfield opportunities. Internal estimates. (3) CARB Scoping Plan: AB32 Source Emissions Final Modeling Results, October 28, 2022. (4) Department of Energy Hydrogen Program Plan, U.S. Department of Energy, November 2020. Converted from CARB's estimated 13% of U.S. hydrogen demand of 21 – 44 MMTPA. (5) Internal estimates.

Ongoing Discussions With Multiple Emitter Types

Project Type[1]	Tech	Greenfield				Existing Sources
Type of Emitter	DAC	Renewable Diesel	Ammonia	Hydrogen	Ethanol	Refiners, Cement, Steam Generators and Natural Gas Power Plants (incl. CalCapture)
Cost of Capture ($/T$CO_2$)	Very High	Medium	Low	Medium	Low	Medium to High
Concentration of CO_2	Very Low	Medium	High	Medium	High	Low to Medium
LCFS Eligible?	Yes, plus Incremental Incentives	Yes	Depends on Use	Depends on Use	Yes	Depends on Use



Existing Emissions Sources[2]

New Greenfield Projects

Projected to Meet the CTV Type Curve Given the Right Criteria

Benefits of the Greenfield projects producing the New Energy Molecule

- **Facility can be co-located with storage** minimizing transportation requirements
- Typically have medium - high **concentration CO_2 emission streams** which **lowers the cost of capture**
- **Can become highly competitive with LCFS compliant molecules** given limited capital required for capture, transport and close proximity to storage facilities

(1) Source: Internal estimates. (2) 2020 CARB.

CTV JV – Presenting Three Additional Assets

CARBON TERRAVAULT JV

Carbon TerraVault JV ("CTV JV")

26R[1]

	Initial Payment	Milestone 2	Milestone 3	
	Brookfield $46MM	Brookfield $46MM	Brookfield $46MM	Brookfield 49% Capital Call For Project Development
	Reservoir Vault Dropdown	*Permit Public Comment Expiration*	*FID*	*Project Capital Call*

CRC's portion of capital calls can be satisfied with Brookfield's contribution retained by the CTV JV

CTV presented for a review three additional reservoirs to CTV JV with a combined capacity of 90 MMT

- A1-A2
- CTV II
- CTV III

Future Potential Dropdowns

If Accepted

- Brookfield to Pay Initial Payment ($10/Ton x Permitted Pore Space x 49% / 3)
- Brookfield to Pay Milestone Payment at Permit Public Comment Expiration ($10/Ton x Permitted Pore Space x 49% / 3)
- Brookfield to Pay Milestone Payment at FID ($10/Ton x Permitted Pore Space x 49% / 3)

Brookfield Retains the Right to Defer the Approval Decision Through FID

If Deferred, Projects to be Re-presented to Brookfield at FID

- If Approved, Brookfield to Pay Lump Sum for Full Buy-in ($10/Ton x Permitted Pore Space x 49%) + % Carry[2] to CRC
- If Rejected, CRC is Free to Develop the Reservoir / Project Outside of the CTV JV[1]

26R → A1-A2 → CTV II → CTV III → Future Potential Dropdowns →

26R	A1-A2, CTV II, CTV III	Future Potential Dropdowns
~30MMT	~90MMT	~80 MMT

Contributed · ROFL Notice Delivered · TBA

YE2027 200MMT Storage CTV JV Target[3]

Note: CTV JV terms simplified for illustrative purposes. Source: Internal estimates. (1) As it pertains to a previously contributed reservoir, in the case Brookfield is not interested in jointly pursuing a specific opportunity, CRC retains the right to rent back up to 25% of the permitted pore space to pursue stated storage opportunity on its own accord. (2) Calculated from date of initial ROFL presentation at certain milestone. (3) Assumes Brookfield fully participates in CCS projects up to JV target of 5MMTPA of injection and 200MMT of CO_2 storage.

A DIFFERENT KIND OF ENERGY COMPANY

Delivering Consistent & Predictable Free Cash Flow

Disciplined Capital Allocation Underpins Robust Shareholder Return Strategy

Advancing & Accelerating Carbon Management Business

Leading Strategic CCS Partnership

2045 Brookfield

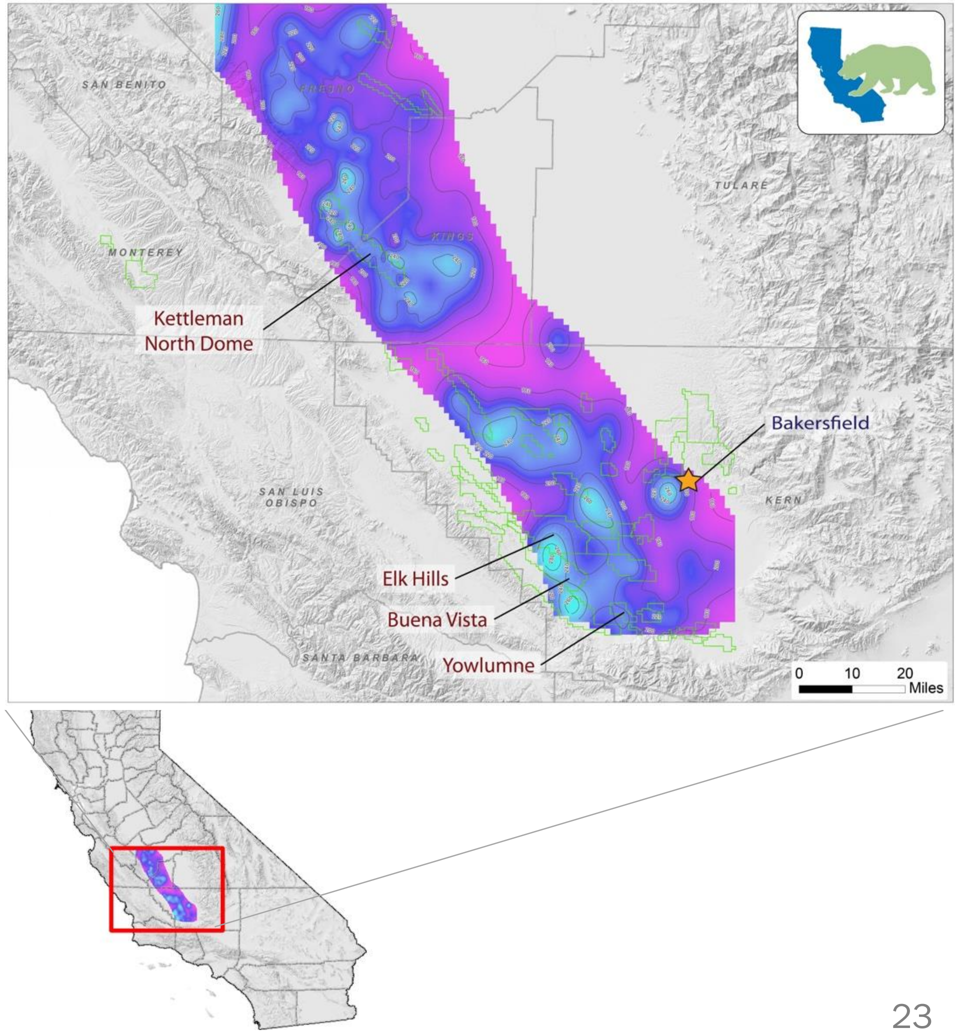
Supplemental Materials

Exploring Technologies to Further Advance Net Zero Energy Pathways

CALIFORNIA RESOURCES CORPORATION COMPANY | ICE THERMAL HARVESTING

Est. ~6MW of Geothermal Opportunities in SJB

- Partnering with ICE Thermal Harvesting ("ICE"), who was awarded a ~$2MM "Wells of Opportunity" grant from the DOE
- Provides an avenue for CRC to pilot a new zero-carbon energy technology
- Potential commercial benefits: field electrical cost reductions, decreased emissions, postponement of asset retirement obligations, increased reliability of power and improved economics
- Project kicked off in October 2022 and is expected to last 3 to 4 years with a potential for free zero-emissions electricity capable to power 6 wells
- Initial planned location at Elk Hills with prospects to expand this technology to other fields or to other applications:
  - Areas of Elk Hills, Buena Vista, Yowlumne, Kern Front, and Kettleman are associated with geothermal opportunities

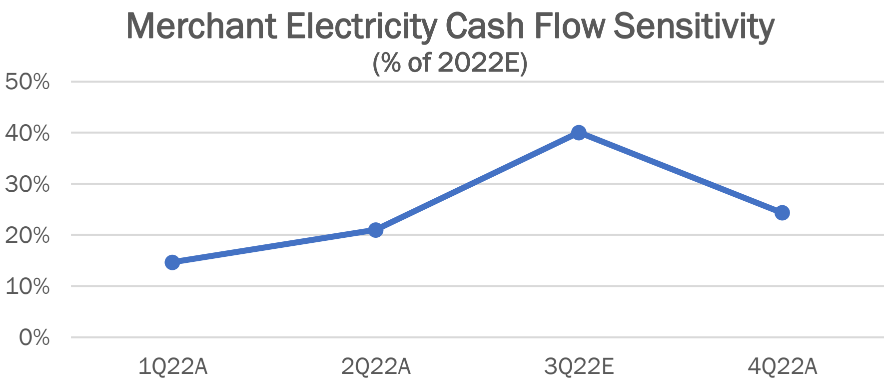


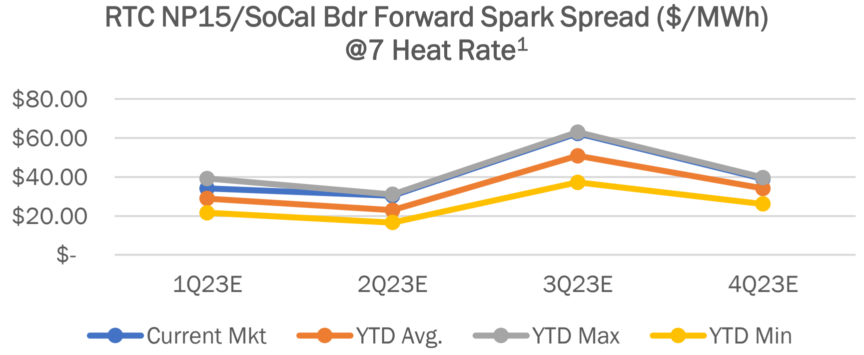
Source: ICE Thermal Harvesting, CRC Internal

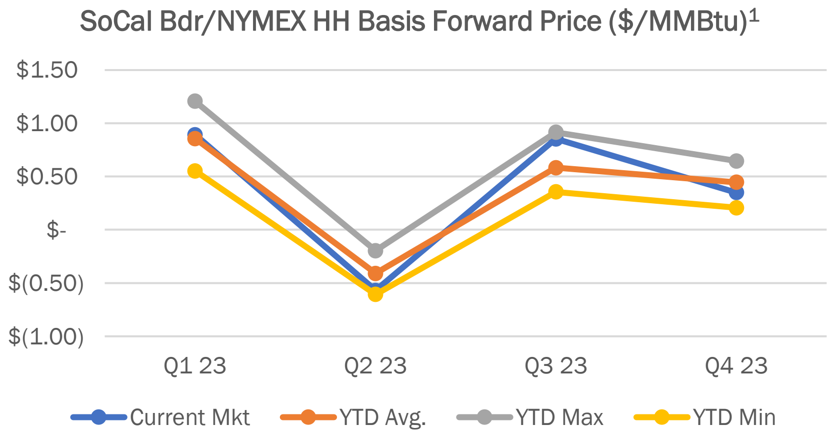
Expected Quarterly Pricing and Timing in '23 Should Remain Consistent with '22 Cashflow Trends

- Cash Inflow Drivers: Natural gas basis differential and power prices/NGLs seasonality + resource adequacy
- Cash Outflow Drivers: Timing related to payment of taxes other than income, insurance, interest and cash incentive bonuses
- Additional impactful Items: Cash income taxes + early CMB expenses
- Note: CRC is net long in natural gas

% of 2022E / Yearly Avg.	1Q22A	2Q22A	3Q22A	4Q22E	2022E
Cash Inflow					
Merchant Electricity Sales ($MM)	15%	22%	40%	23%	~$220
SoCal Border to NYMEX HH Basis Differential ($/MMBtu) Yearly Avg.	232%	39%	137%	-7%[1]	~$0.92
NGL Seasonality ($/bbl) Yearly Avg.	119%	103%	87%	91%[1]	~$66
Cash Outflow					
RTC Power Prices ($/MW) Yearly Avg.	76%	105%	89%	129%[1]	~$64
Interest Payments (February/August) ($MM)	46%	4%	46%	4%	~$50
Taxes Other than Income ($MM)	34%	16%	22%	29%	~$110
Insurance Premiums ($MM)	5%	37%	5%	53%	~$20
Est. CF Impact		Lowest CF	Highest CF		

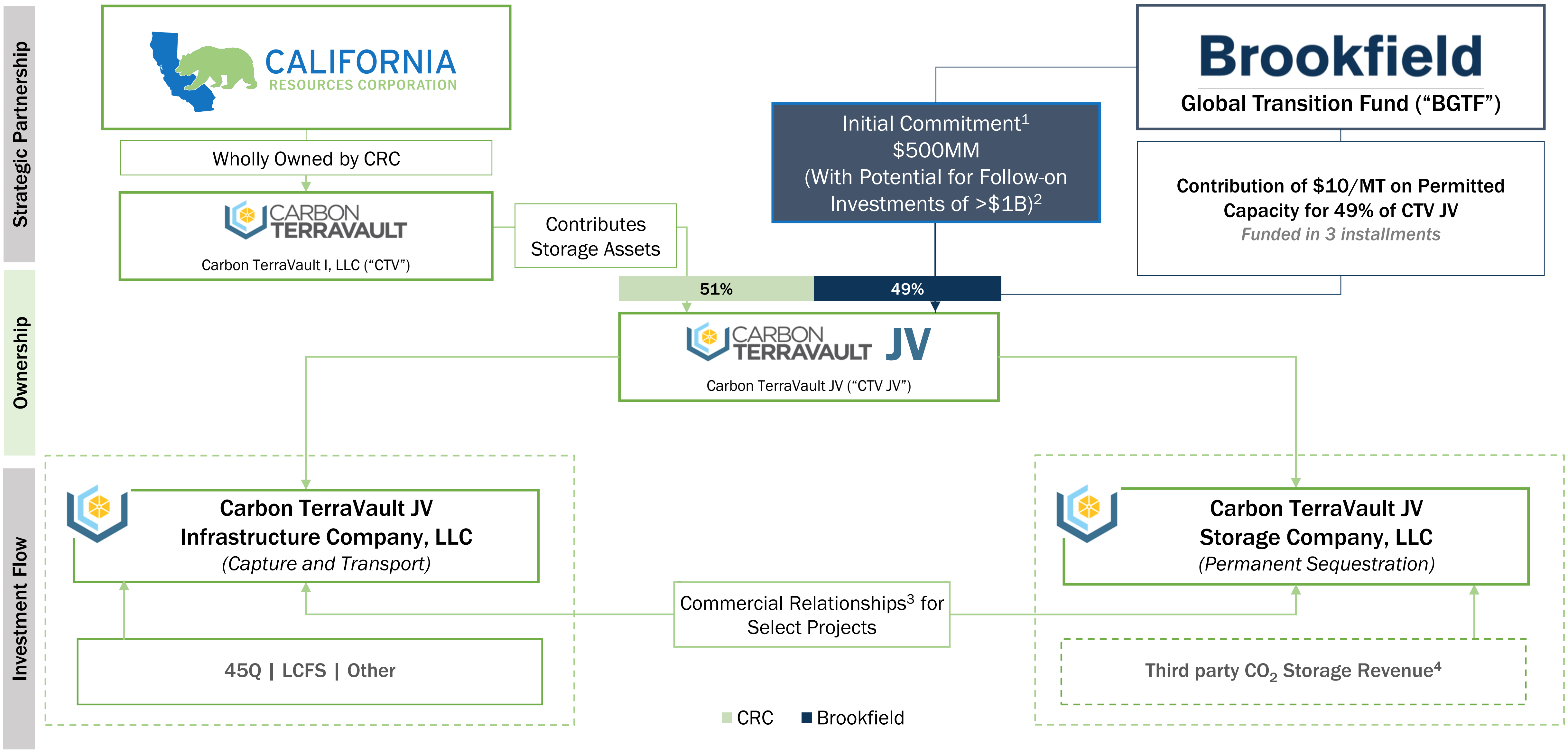






(1) Based on strip pricing as of September 30, 2022.

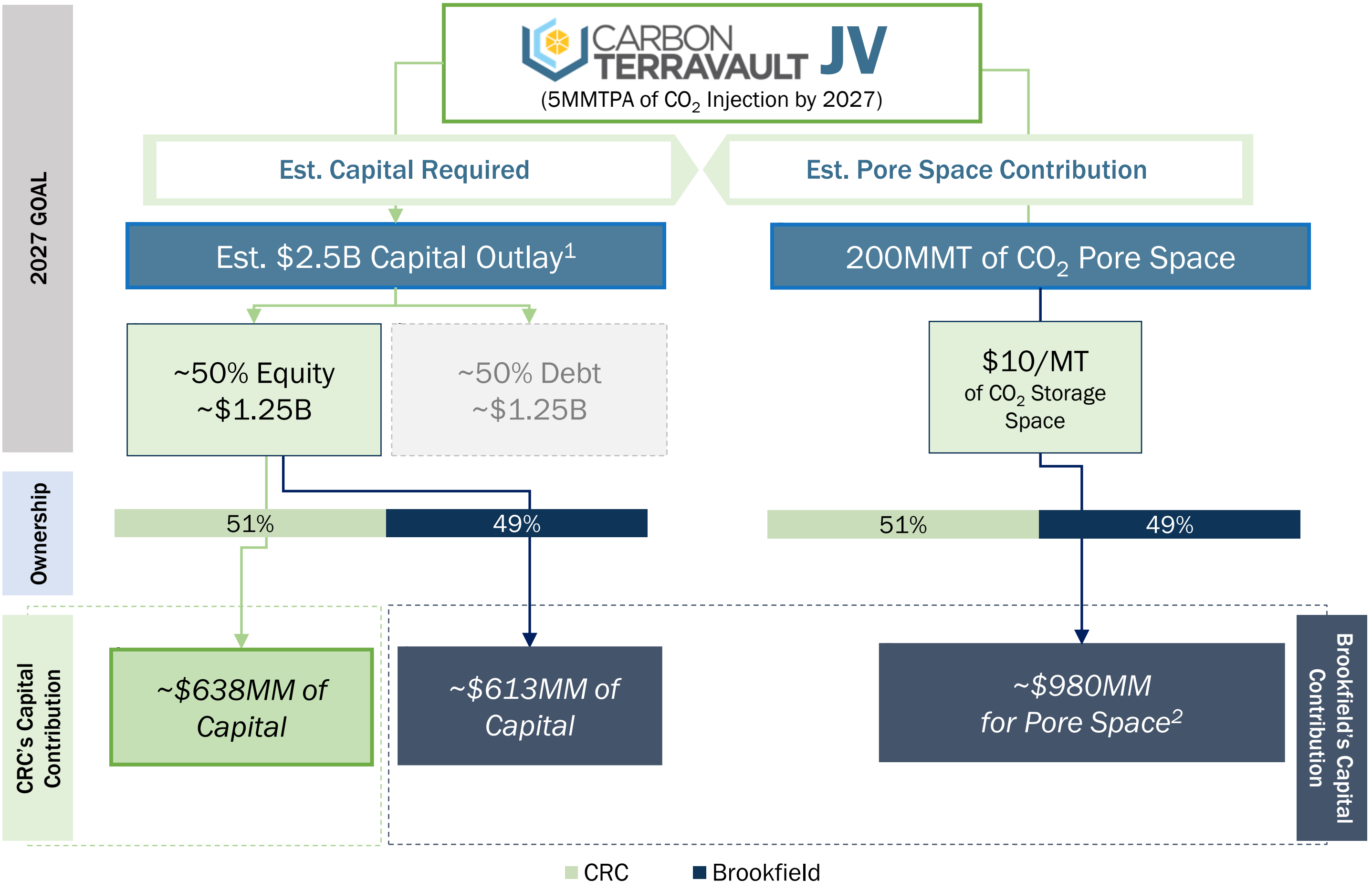
Strategic Partnership – Carbon TerraVault Joint Venture (CTV JV) Details



Note: CTV JV diagram for illustrative purposes only. (1) Commitment applies to CCS projects that are jointly approved through the JV. (2) Assumes Brookfield fully participates in CCS projects up to JV target of 5MMTPA of injection and 200MMT of CO_2 storage. (3) Additionally, CRC will provide operational and other services to the joint venture. (4) Independent of Infrastructure Co.

Strategic Partnership – A Structural Capital Advantage

Illustrative 2027 CO_2 Storage/Injection Goal Capital Funding Needs[1]



Improves & Increases Flexibility of CRC's Capital Allocation Framework

- Capitalizes first 5MMTPA of projects and provides potential funding for CRC's development of 200MMT of CO_2 storage by 2027
- CRC's equity commitments are more than 2x covered by Brookfield's storage buy-in commitments
- Allows CRC to increase flexibility for shareholder returns strategy and explore strategic alternatives for low CI E&P business expansion

(1) Assumes the average capital needs for 5MMTPA of Carbon Sequestration from the CTV JV economic "Type Curve" on slide 27. (2) ~$980MM assumes 200MMT of CO_2 pore space for $10/MT of CO_2 storage space and 49% Brookfield ownership which assumes Brookfield fully participates in CCS projects up to JV target of 5MMTPA of injection and 200MMT of CO_2 storage.

CTV Project Economic "Type Curve"

Potential Economic Incentives[1]

FEDERAL 45Q TAX CREDIT

$85 (2026) Value (per MT of CO_2) for Carbon Storage

+

CALIFORNIA LOW CARBON FUEL STANDARD (LCFS)

~$120 Est. Value Range (per MT of CO_2)

+

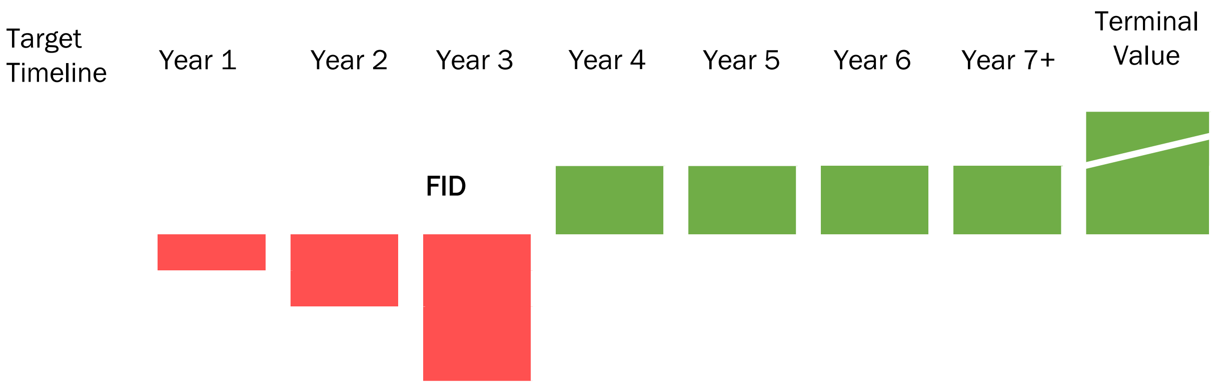
CALIFORNIA CAP & TRADE PROGRAM POTENTIAL[2]

Average trading price YTD is at ~$30 per MT of CO_2

EXAMPLE PROJECT ASSUMPTIONS

Please see slide 38 for a description of assumptions used above. This information is an example of project economics for a strategic partnership project. The terms and availability of third-party sources of financing, if needed, could also affect returns and outcomes.

Example Strategic Partnership Project Cash Flow Profile[3]

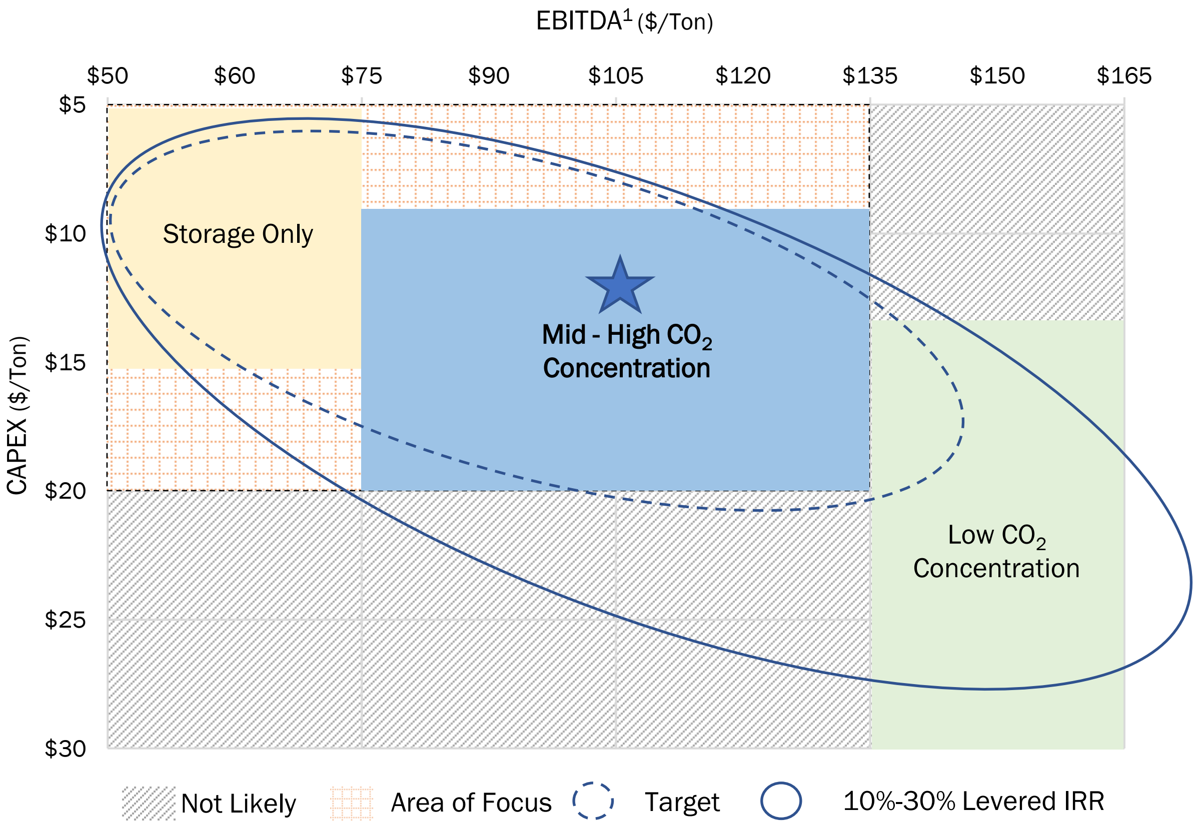


Example **Strategic Partnership Economics** An average CTV project could generate on average **$50 to $135 of EBITDA[4] per metric ton injected per annum** depending on project structure.

Note: CTV JV terms simplified for illustrative purposes. (1) Source: LCFS YTD average price of $123 per MT of CO_2 - The California Air Resources Board – average 2022 Type 1 transfer YTD pricing as of July 15, 2022. 45Q assumes wage and apprenticeship requirements are met. (2) Source: CARB; California's Cap and Trade program currently doesn't cover CCS and requires regulatory changes to be implemented that may not materialize. Represents average auction prices for 2022 as of July 15, 2022. (3) Est. cash flow positive in year 4 with payback period of ~ 4 to 6 years and reflects the midpoint of range estimates. (4) Earnings before interest, taxes, depreciation and amortization (EBITDA) is a non-GAAP measure. EBITDA estimates include 45Q tax credits.

Large Opportunity Set With a Variety of Potential Emitters

Illustrative EBITDA[1] vs CAPEX Requirements for Various CO_2 Projects



STORAGE ONLY PROJECTS

- CTV JV is the off-taker of CO_2 at storage site through Storage Co.
- Lower expected capital requirements for project development, including injection and monitoring wells, facilities and compression

MID - HIGH CO_2 CONCENTRATION PROJECTS

(≥15% CO_2 STREAM CONCENTRATION)

- CTV JV controls the entire value chain (capture to storage) and majority of the incentives
- Capital requirements for capture systems, while still significant, are expected to be on the lower end of the capture cost curve due to higher CO_2 concentration of stream
- Project financing more likely vs. storage only and provides opportunity to increase levered returns
- Potential LCFS expansion could provide further EBITDA potential

LOW CO_2 CONCENTRATION PROJECTS

(<15% CO_2 STREAM CONCENTRATION)

- CTV JV controls value chain and incentive but lower expected IRR due to higher costs of capture (*Ex: Natural Gas Combined Cycle Power Plants*)
- Inflation Reduction Act of 2022 expands potential project opportunities
- Advancements in capture technology to play key role in improving project economics
- CARB considering new incentive programs to unlock traditionally hard to decarbonize sectors (e.g. cement)
- CalCapture[2] is an advantaged low CO_2 concentration project given its proximity to storage (insignificant transport capital)

Note: Depicts illustrative examples of expected IRR, EBITDA and capital expenditure requirements based on internal estimates. Actual results could differ materially. (1) EBITDA is a non-GAAP measure. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. Note CTV JV EBITDA estimates include 45Q tax credits. (2) CalCapture refers to CRC's project at the Elk Hills Power Plant.

CTV JV – Creates Value & De-risks Project Funding Requirements

Illustrative Strategic Partnership Transaction Bridge

Illustrative Assumptions:

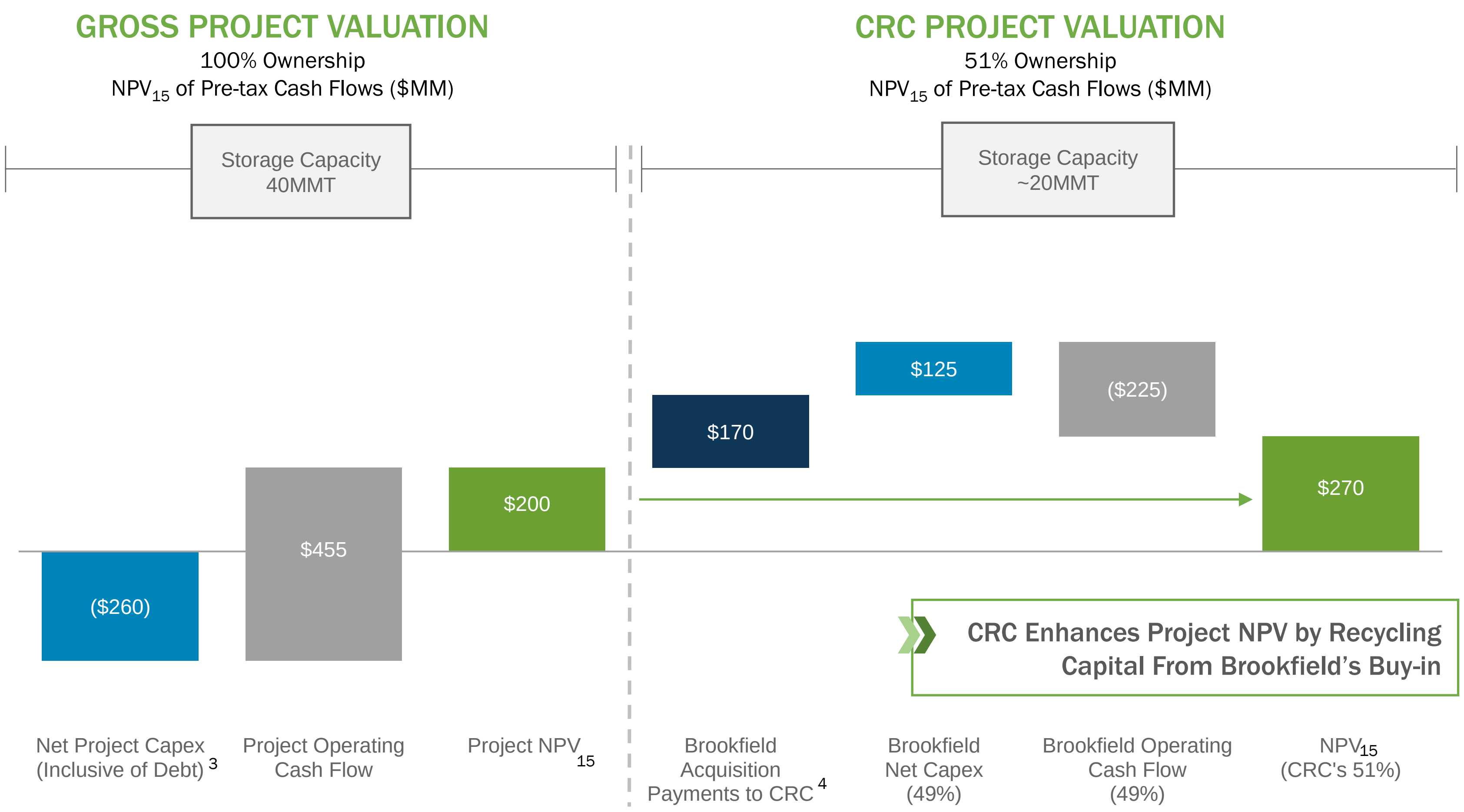
(Mid-High Concentration CO_2 stream)

- CCS Service[1] (Capture Through Storage)
- Annual Injection: 1MMTPA
- Project Term: 40 Years
- Storage Capacity: 40 MMT
- Capex per Injected Ton: ~$12.50[2]
- EBITDA per Ton: ~$105
- Shown on a Levered Basis
  - 50% LTV
  - 6% Interest Rate
- Discount Rate: 15%
- JV to Target Mid-Teens IRR

Implied 200MMT Metrics:

Levered CRC NPV_{15}: ~$1.36B

(~$272 MM NPV_{15} x 5 projects)

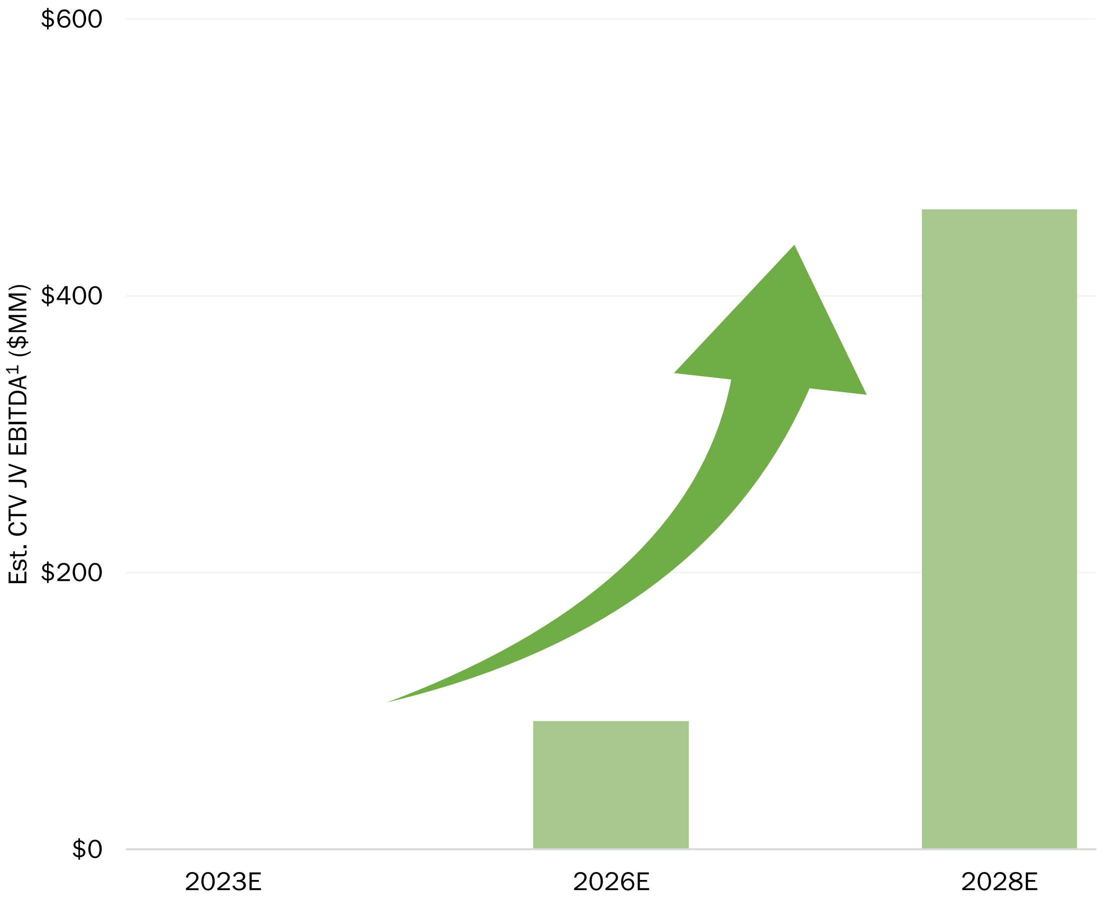


Note: CTV JV terms simplified for illustrative purposes. Development assumptions represent the mid-point of the CTV JV economic "Type Curve" (see slide 27 for additional details); NPV assumes mid-year discounting convention. Some amounts are rounded for illustrative purposes. Actual results could defer materially. (1) See slide 19 of CRC's Carbon Storage Update Presentation from October 6, 2021, for details on various CTV business models. (2) Capex is modeled 15% in project year one, 25% in project year two, and 60% in project year three. (3) Net Capex inclusive of NPV_{15} from 50% debt financing (principal + repayments) and assumes debt is fully funded in project year three. Interest payments related to the debt are included in Operating Cash Flow. (4) Brookfield acquisition payments reflect the NPV of the Brookfield buy-in calculated as $65MM due in project year one, project year two and project year three, respectively, for an aggregate amount of $196 MM ($10/ton acquisition price for 40MMT of permitted pore space and the 49% working interest of Brookfield).

Potential CTV JV Valuation Upside

Targeting ~$465MM of EBITDA[1] by 2028

Assuming midpoint of the CTV Project Economic "Type Curve" on page 10



CTV JV EBITDA[1] Potential

	2026E	2028E
Est. CO_2 Injection Rate per Year	1MMTPA	5MMTPA
Est. CTV JV EBITDA[1] ($MM)	$50 - $135	$250 - $675

EXAMPLE CTV JV PROJECT ECONOMICS

(PER MT OF INJECTED CO_2)

	Unit	Low	High	Notes/Incorporated Assumptions
Total Incentive Potential (LCFS + 45Q)	$/MT	$170	$205	45Q ($/MT): $85, LCFS ($/MT): $85 - $120, 100% LCFS eligibility
Opex	$/MT	$25	$75	Range reflects costs associated with full range of business model possibilities and includes G&A of dedicated staff.
Capex	Avg $/MT	$5	$20	Range of capital includes cost of capture facility and pipeline retrofit. Cost of capture facility depends on CO_2 concentration at source. Pipeline costs depend on distance from source to sink and size of pipe. Pace of capex deployment is expected to be ~5% to ~10% of Total Project Capex in Year 1, ~10% to ~35% in Year 2 and ~55% to ~85% in Year 3. Depending on project structure and location, capex could be lower or higher than range represented.

Note: Development assumptions represent the mid-point of the CTV JV economic "Type Curve" (see slide 27 for additional details). (1) EBITDA is a non-GAAP measure. Note CTV JV EBITDA estimates include 45Q tax credits. Assumes Brookfield fully participates in CCS projects up to JV target of 5MMTPA of injection and 200MMT of CO2 storage. EBITDA calculations presented assume the top and bottom ranges of the EBITDA assumptions on page 10 multiplied by 1MM and 5MM to represent 1MMTPA of projects and 5MMTPA of projects, respectively.

Hedging Program

STRATEGY

CRC's hedging strategy is focused on supporting capital to maintain oil production, interest payments on debt, shareholder returns, and our CMB operations

HEDGE CONTRACT SETTLEMENTS EXPECTED TO SIGNIFICANTLY DECREASE IN 2023[3]

	2021	1Q22	2Q22	3Q22E	4Q22E	2022E	1H23E	2H23E	2023E
Hedge Contract Settlements[4] ($MM)	($319)	($181)	($241)	($182)	($111)	($715)	($130)	($84)	($214)

OIL HEDGES[1]

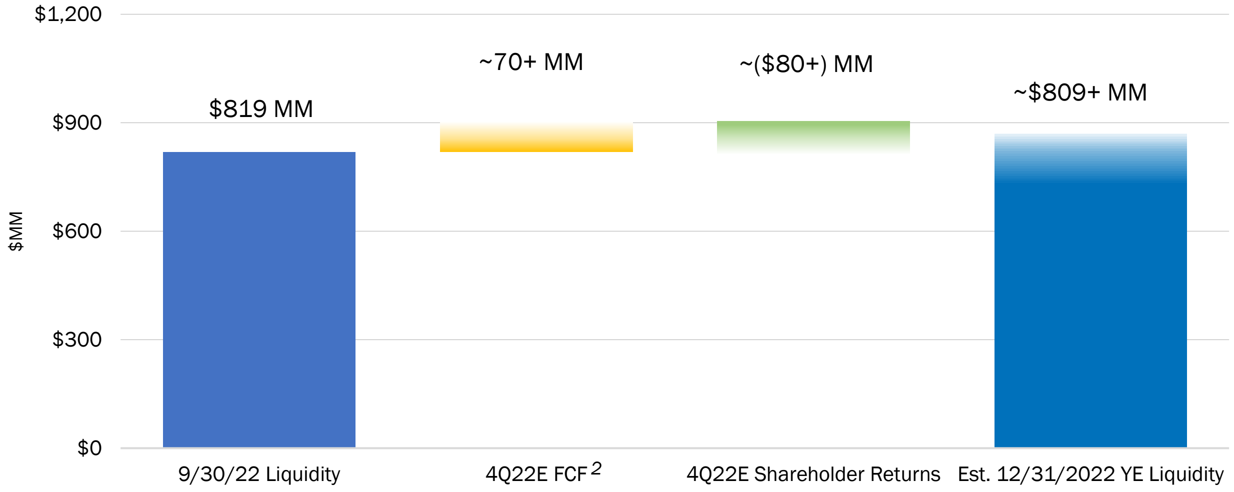
Date as of September 30, 2022

		4Q22	1Q23	2Q23	3Q23	4Q23	2024
SOLD CALLS	Barrels per Day	25,167	18,322	17,837	17,363	5,747	—
	Weighted-Average Price per Barrel	$57.82	$57.28	$60.00	$57.06	$57.06	—
SWAPS	Barrels per Day	17,263	14,620	14,475	14,697	24,094	1,492
	Weighted-Average Price per Barrel	$58.79	$67.36	$66.36	$66.27	$69.14	$79.06
NET PURCHASED PUTS[2]	Barrels per Day	25,167	18,322	17,837	17,363	5,747	1,724
	Weighted-Average Price per Barrel	$64.47	$76.25	$76.25	$76.25	$76.25	$75.00
SOLD PUTS	Barrels per Day	1,348	—	—	—	—	—
	Weighted-Average Price per Barrel	$32.00	—	—	—	—	—

1) Hedges are based on weighted-average Brent prices per barrel. CRC also entered NG hedges which can be found in its 3Q22 10-Q. (2) Purchased and sold puts with the same strike price have been netted together. (3) Assumes commodity pricing remains at the similar levels as of September 30, 2022 (4) Represents estimated net cash settlement payments for derivative contracts as of 9/30/2022, except 2021, 1Q22, 2Q22 and 3Q22 which are actuals for the year ended on December 31, 2021, and three months ended March 31, 2022, June 30, 2022 and September 30, 2022, respectively.

Maintaining Balance Sheet Strength, Liquidity, and Financial Flexibility

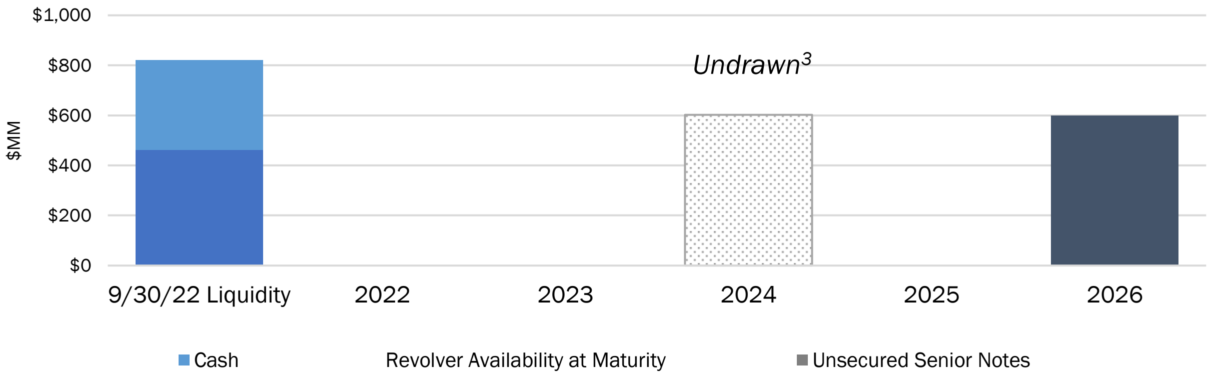
ESTIMATED LIQUIDITY ROLL FORWARD[1]



9/30/22 NET DEBT SNAPSHOT

($MM)		
Revolving Credit Facility (RCF)[1]	$	0
7.125% Senior Notes		600
Face Value of Debt	**$**	**600**
Less Available Cash		(358)
Net Debt[2]	**$**	242

NO SIGNIFICANT MATURITIES UNTIL 2026



MULTIPLES DEMONSTRATE FLEXIBILITY

($MM)	
RCF Borrowing Base	$ 1,200
2022E Free Cash Flow[2]	$325 – $370
YE 2022E Net Debt[1,2] / 2022E Adjusted EBITDAX[2]	0.2x – 0.4x
2022E Adjusted EBITDAX[2] / 2022E Interest & Debt Expense, net	16.1x – 17.5x

(1) Liquidity at 9/30/22 calculated as unrestricted cash of $358 MM and $602 MM capacity on CRC's Revolving Credit Facility less $141 MM in outstanding letters of credit. Estimated YE 2022 liquidity assumes $602 MM capacity on CRC's Revolving Credit Facility less $141 MM in outstanding letters of credit. 2022 estimated FCF reflects the midpoint of 2022 Free Cash Flow guidance less $272 MM of FCF YTD 2022. 4Q 2022 estimated shareholder returns includes a dividend payment of $0.2825 based on ~73 MM shares outstanding and a similar quarterly rate of repurchases as 3Q22, which are both subject to company discretion. (2) Adj. EBITDAX, Net Debt and Free Cash Flow are non-GAAP measures. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. Reconciliations of 2022E Adj. EBITDAX, Net Debt and Free Cash Flow to their nearest GAAP equivalent can be found in the Supplemental Materials on slides 33 to 37. (3) Undrawn revolver as of September 30, 2022.

Adjusted EBITDAX Reconciliation

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 represents a reconciliation of the GAAP financial measures of net income and net cash provided by operating activities to the non-GAAP financial measure of adjusted EBITDAX. CRC has supplemented its non-GAAP measures of consolidated adjusted EBITDAX with adjusted EBITDAX for its exploration and production and corporate items (Adjusted EBITDAX for E&P, Corporate & Other) which CRC believes is a useful measure for investors to understand the results of its core oil and gas business. CRC defines adjusted EBITDAX for E&P, Corporate & Other as consolidated adjusted EBITDAX less results attributable to its carbon management business (CMB).

	FY 2022E		CMB 2022E		E&P, Corp. & Other 2022E	
($MM)	Low	High	Low	High	Low	High
Net income	$612	$650	($35)	($20)	$647	$670
Interest and debt expense, net	51	52	-	-	51	52
Depreciation, depletion and amortization	200	202	-	-	200	202
Exploration expense	5	10	-	-	5	10
Income Taxes	273	277	-	-	273	277
Unusual, infrequent and other items						
Non-cash derivative gain	(318)	(315)	-	-	(318)	(315)
Gain on asset divestitures	(60)	(60)	-	-	(60)	(60)
Other	10	10	-	-	10	10
Other non-cash items						
Accretion expense	43	44	-	-	43	44
Equity settled stock-based compensation	17	18	-	-	17	18
Post-retirement medical and pension	2	2	-	-	2	2
Estimated Adjusted EBITDAX	**$835**	**$890**	($35)	($20)	$870	$910

	FY 2022E		CMB 2022E		E&P, Corp. & Other 2022E	
($MM)	Low	High	Low	High	Low	High
Net cash provided by operating activities	$725	$750	($35)	($20)	$760	$770
Cash Interest	50	52	-	-	50	52
Cash Income Taxes	30	36	-	-	30	36
Exploration expenditures	5	10	-	-	5	10
Working capital changes	25	42	-	-	25	42
Estimated Adjusted EBITDAX	**$835**	**$890**	($35)	($20)	$870	$910

Note: Adj. EBITDAX is a non-GAAP measure. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information.

Adjusted EBITDAX Reconciliation (Cont.)

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 represents a reconciliation of the GAAP financial measures of net income and net cash provided by operating activities to the non-GAAP financial measure of adjusted EBITDAX. CRC has supplemented its non-GAAP measures of consolidated adjusted EBITDAX with adjusted EBITDAX for its exploration and production and corporate items (Adjusted EBITDAX for E&P, Corporate & Other) which CRC believes is a useful measure for investors to understand the results of its core oil and gas business. CRC defines adjusted EBITDAX for E&P, Corporate & Other as consolidated adjusted EBITDAX less results attributable to its carbon management business (CMB).

	4Q22E		CMB 4Q22E		E&P, Corp. & Other 4Q22E	
($MM)	**Low**	**High**	Low	High	Low	High
Net income	$176	$191	($14)	($5)	$190	$196
Interest and debt expense, net	12	14	-	-	12	14
Depreciation, depletion and amortization	50	52	-	-	50	52
Exploration expense	1	2	-	-	1	2
Income Taxes	65	75	-	-	65	75
Unusual, infrequent and other items						
Non-cash derivative gain	(135)	(130)	-	-	(135)	(130)
Gain on asset divestitures	-	-	-	-	-	-
Other	13	13	-	-	13	13
Other non-cash items						
Accretion expense	10	12	-	-	10	12
Equity settled stock-based compensation	3	5	-	-	3	5
Post-retirement medical and pension	1	1	-	-	1	1
Estimated Adjusted EBITDAX	**$196**	**$235**	($14)	($5)	$210	$240

	4Q22E		CMB 4Q22E		E&P, Corp. & Other 4Q22E	
($MM)	**Low**	**High**	Low	High	Low	High
Net cash provided by operating activities	$151	$165	($14)	($5)	$165	$170
Cash Interest	2	4	-	-	2	4
Cash Income Taxes	10	14	-	-	10	14
Exploration expenditures	1	2	-	-	1	2
Working capital changes	32	50	-	-	32	50
Estimated Adjusted EBITDAX	**$196**	**$235**	($14)	($5)	$210	$240

Note: Adj. EBITDAX is a non-GAAP measure. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information.

Leverage Ratio & Net Debt Reconciliations

Leverage Ratio and Net Debt

We calculate the leverage ratio by dividing net debt by adjusted EBITDAX for the applicable period. We define net debt as the face value of our debt less available cash. We believe the leverage ratio is an important metric of the operational and financial health of our Company and is useful to investors as an indicator of our ability to incur additional debt and to service our existing debt. The following table presents a reconciliation of our leverage ratio. The leverage ratio is a supplemental measure of our performance that is not required by or presented in accordance with U.S. generally accepted accounting principles ("GAAP").

	FY 2022E	
($MM)	**Low**	**High**
Face value of debt	$600	$600
Estimated available cash[1]	(400)	(300)
Estimated Net Debt as of December 31, 2022	**$200**	**$300**
2022E Adjusted EBITDAX	$890	$835
2022E Leverage Ratio	**0.22x**	**0.36x**

Note: Adj. EBITDAX and Net Debt are non-GAAP measures. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. (1) Inclusive of dividends and share repurchases. Please see slide 32 for a for a description of expected liquidity changes in 2022.

Free Cash Flow & Adjusted General & Administrative Expenses Reconciliations

Free Cash Flow

Management uses free cash flow, which is defined by us as net cash provided by operating activities after our internal capital investment, as a measure of liquidity. The table below presents a reconciliation of net cash provided by operating activities to free cash flow. CRC has supplemented its non-GAAP measures of consolidated free cash flow with free cash flow from our exploration and production and corporate items (free cash flow from E&P, Corporate & Other) which CRC believes is a useful measure for investors to understand the results of its core oil and gas business. CRC defines free cash flow from E&P, Corporate & Other as consolidated free cash flow less results attributable to CMB.

	FY 2022E		CMB 2022E		E&P, Corp. & Other 2022E	
($MM)	Low	High	Low	High	Low	High
Net Cash Provided (Used) by Operating Activities	$725	$750	($35)	($20)	$760	$770
Capital Investment	(400)	(380)	(30)	(20)	(370)	(360)
Estimated Free Cash Flow	$325	$370	($65)	($40)	$390	$410

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. We supplemented our non-GAAP measure of adjusted general and administrative expenses with adjusted general and administrative expenses of our exploration and production and corporate items (Adjusted General & Administrative Expenses for E&P, Corporate & Other) which we believe is a useful measure for investors to understand the results or our core oil and gas business. We define Adjusted General & Administrative Expenses for E&P, Corporate & Other as consolidated adjusted general and administrative expenses less results attributable to our carbon management business.

	FY 2022E		CMB 2022E		E&P, Corp. & Other 2022E	
($MM)	Low	High	Low	High	Low	High
General & Administrative Expenses	$220	$230	$10	$15	$210	$215
Equity-settled Sock-based Compensation	(20)	(15)	-	-	(20)	(15)
Other	(5)	(5)	-	-	(5)	(5)
Estimated Adjusted General & Administrative Expenses	$195	$210	$10	$15	$185	$195

Note: Free Cash Flow and Adjusted G&A are non-GAAP measures. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information.

Free Cash Flow & Adjusted General & Administrative Expenses Reconciliations (Cont.)

Free Cash Flow

Management uses free cash flow, which is defined by us as net cash provided by operating activities after our internal capital investment, as a measure of liquidity. The table below presents a reconciliation of net cash provided by operating activities to free cash flow. CRC has supplemented its non-GAAP measures of consolidated free cash flow with free cash flow from our exploration and production and corporate items (free cash flow from E&P, Corporate & Other) which CRC believes is a useful measure for investors to understand the results of its core oil and gas business. CRC defines free cash flow from E&P, Corporate & Other as consolidated free cash flow less results attributable to CMB.

	4Q22E		CMB 4Q22E		E&P, Corp. & Other 4Q22E	
($MM)	Low	High	Low	High	Low	High
Net Cash Provided (Used) by Operating Activities	$151	$165	($14)	($5)	$165	$170
Capital Investment	(88)	(74)	(8)	(4)	(80)	(70)
Estimated Free Cash Flow	**$63**	**$91**	($22)	($9)	$85	$100

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. We supplemented our non-GAAP measure of adjusted general and administrative expenses with adjusted general and administrative expenses of our exploration and production and corporate items (Adjusted General & Administrative Expenses for E&P, Corporate & Other) which we believe is a useful measure for investors to understand the results or our core oil and gas business. We define Adjusted General & Administrative Expenses for E&P, Corporate & Other as consolidated adjusted general and administrative expenses less results attributable to our carbon management business.

	4Q22E		CMB 4Q22E		E&P, Corp. & Other 4Q22E	
($MM)	Low	High	Low	High	Low	High
General & Administrative Expenses	$61	$66	$2	$6	$59	$60
Equity-settled Sock-based Compensation	(5)	(3)	-	-	(5)	(3)
Other	(4)	(2)	-	-	(4)	(2)
Estimated Adjusted General & Administrative Expenses	**$52**	**$61**	$2	$6	$50	$55

Note: Free Cash Flow and Adjusted G&A are non-GAAP measures. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information.

Assumptions & Relevant Footnotes:

Slide 27:

Information presented on slide 27 shows example project economics for a strategic partnership with Brookfield. This information is an example of project economics for the strategic partnership. The terms and availability of third-party sources of financing, if needed, could also affect returns and outcomes.

- Assumes 1MMT injected per year for 40-year project life.
- High end of OPEX range assumes end-to-end value chain business model and low-end assumes carbon storage business model, both described on slide 19 of CRC's Carbon Storage Update on October 6, 2021
- Capex range assumes project capital of between $200MM and $800MM for an end-to-end business model. Project/partnership structures where CRC provides storage only could result in capital ranges below stated ranges.
- Based on incentives available under current regulatory framework.
- The EBITDA[1] range has been reduced by ~20% – 50% to reflect uncertainties related to project structure, financing and ownership.
- Assumes total incentive potential can be monetized through tax equity brokers and LCFS monetized in the LCFS trading marketplace and recorded as revenue. For simplicity, a 5-year accelerated straight line depreciation and amortization is assumed. Assumes no bonus depreciation.
- Payback period is defined as total CRC investment / annual cash flow and is specifically for CTV JV project level economics.

(1) EBITDA and Free Cash Flow are non-GAAP measures. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information.

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