Third Quarter 2023 Results

November 01, 2023

A DIFFERENT KIND OF ENERGY COMPANY

CALIFORNIA RESOURCES CORPORATION | CARBON TERRAVAULT

Presenters

- **Francisco Leon** *President & Chief Executive Officer*
- **Nelly Molina** *EVP & Chief Financial Officer*

Executive Summary– Delivering on Our Plan

CASHFLOW

STRONG FINANCIAL & OPERATIONAL PERFORMANCE

- Generated $71MM of free cash flow[1] during the third quarter and $403MM year to date
- Year to date, returned ~52% or $207MM of free cash flow[1] to stakeholders in form of
  - share repurchases of $143MM,
  - dividends of $59MM, and
  - debt repurchases of $5MM (not including an additional $30MM debt repurchase post 3Q)
- Raising fixed dividend[2] by 10%

CARBON

EXPANDING CTV'S LEADERSHIP IN CALIFORNIA

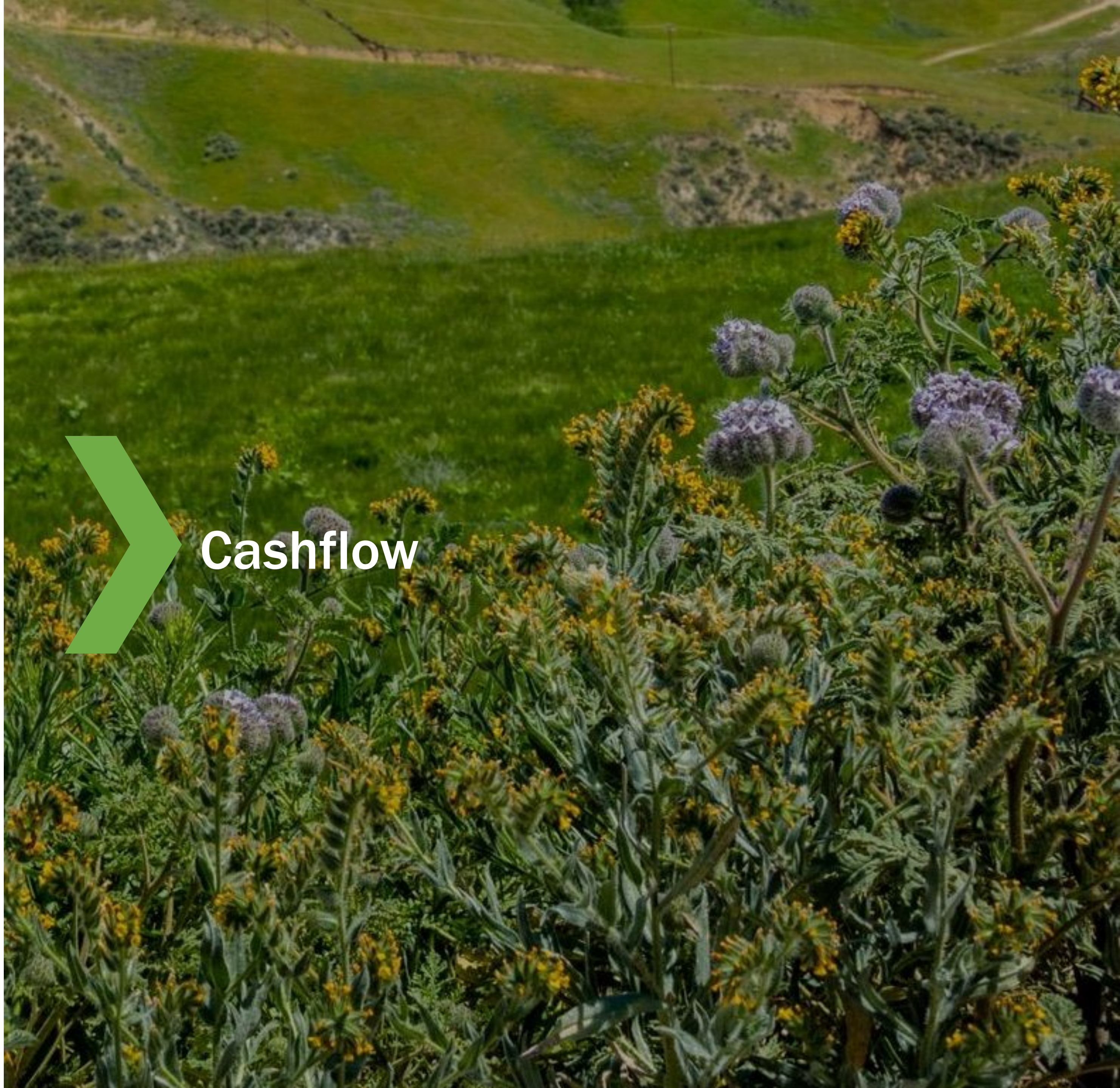
- Announcing two new CO_2 sequestration projects at CTV Clean Energy Park at Elk Hills
  - First capture to storage CTV project from an existing source at Elk Hills Cryo Gas Plant with first expected CO_2 injection by the end of 2025: 100KTPA
  - Storage-only renewable natural gas (RNG) facility with NLC Energy (NLCE): 150KTPA
- EPA's Class VI permit tracker[3] shows CTV I draft permit issued before YE23

CALIFORNIA

DERISKING OUR STORY

- CRC's natural gas incremental inventory[4] > 1 Tcf in Sacramento and San Joaquin basins
- 2024E business plan preview:
  - Line of sight to permitting progression. Plan to start 2024 with 1 rig and increase activity in 2H24
  - Increased EHPP capacity revenue
  - $55MM + in est. cost reductions
  - EHPP turnaround

Note: please see slide 30 for details on the footnotes on this slide.



Cashflow

Delivered Consistent Operational & Financial Performance

A DIFFERENT KIND OF ENERGY COMPANY

	3Q23E[1]	3Q23A
Brent ($/bbl)	$75.28	$85.95
Brent realized price with hedge ($/bbl)	$65.99	$66.12

CRC GUIDANCE	Guidance[1]	Results
Net Total Production (MBOE/D)	86 – 88	85
Net Oil Production (MBO/D)	52 – 54	51
Operating Costs ($MM)	$185 – $205	$196
CMB Expenses[2] ($MM)	$5 – $10	$9
Adj. G&A[3] ($MM)	$52 – $60	$51
Total Capital ($MM)	$52 – $67	$33
Free Cash Flow[3] ($MM)	$30 – $50	$71

Other Guidance Items		
Natural Gas Marketing Margin ($MM)	$20 – $25	$47
Electricity Margin ($MM)	$40 – $50	$44
Transportation Expense ($MM)	$13 – $18	$16

Total quarterly return of cash to stakeholders ($MM)	3Q23A
Share Repurchases ($MM)	$20
Dividend Payment ($MM)	$19
Debt Repurchases ($MM)	$5
Total ($MM)	$44

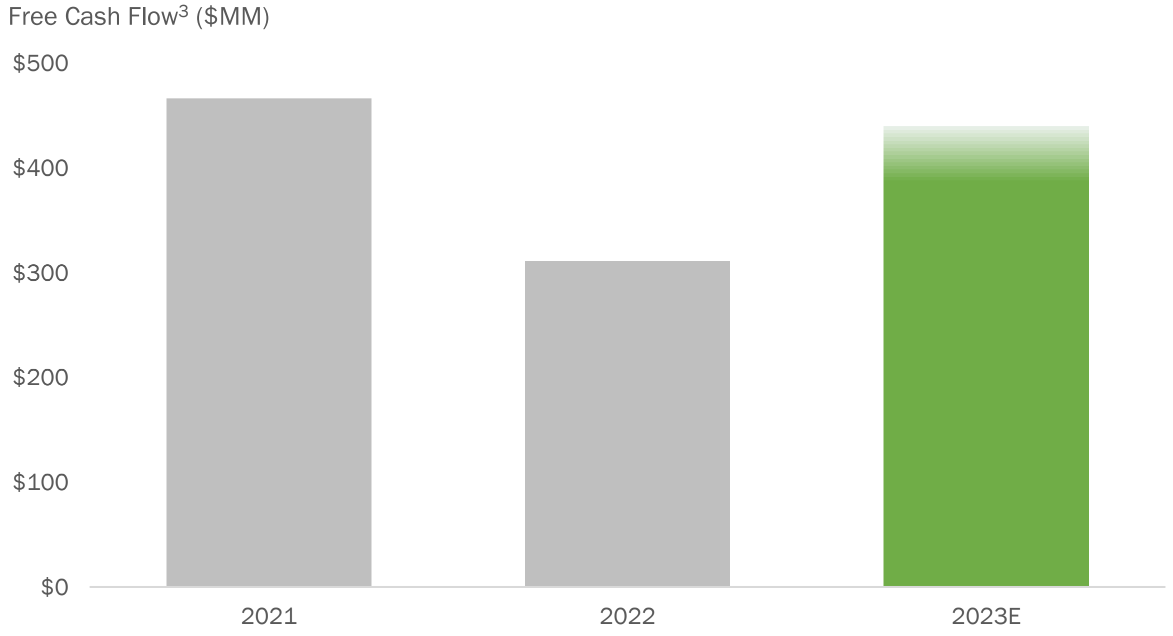
~$11/bbl

rise in QoQ Brent prices contributed to an increase of ~$7MM in operating cash flow[4]; negatively impacted net oil production by 1.2 mbo/d due to PSC effects

62%

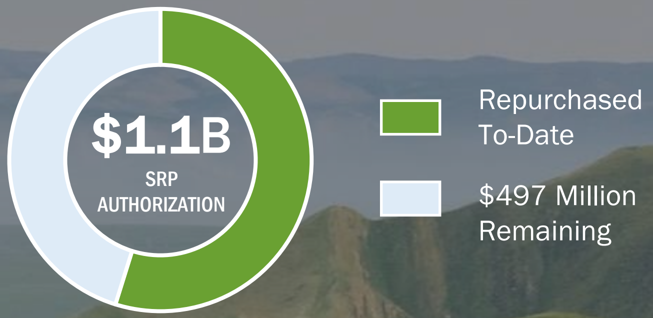
of quarterly free cash flow[3] returned to stakeholders in form of dividends, share repurchases and debt buybacks

STRONG 3Q23 RESULTS PAVE A WAY FOR DELIVERING ROBUST ANNUAL FREE CASH FLOW[3] GENERATION



Note: please see slide 30 for details on the footnotes on this slide.

Proven Commitment to Shareholder Returns



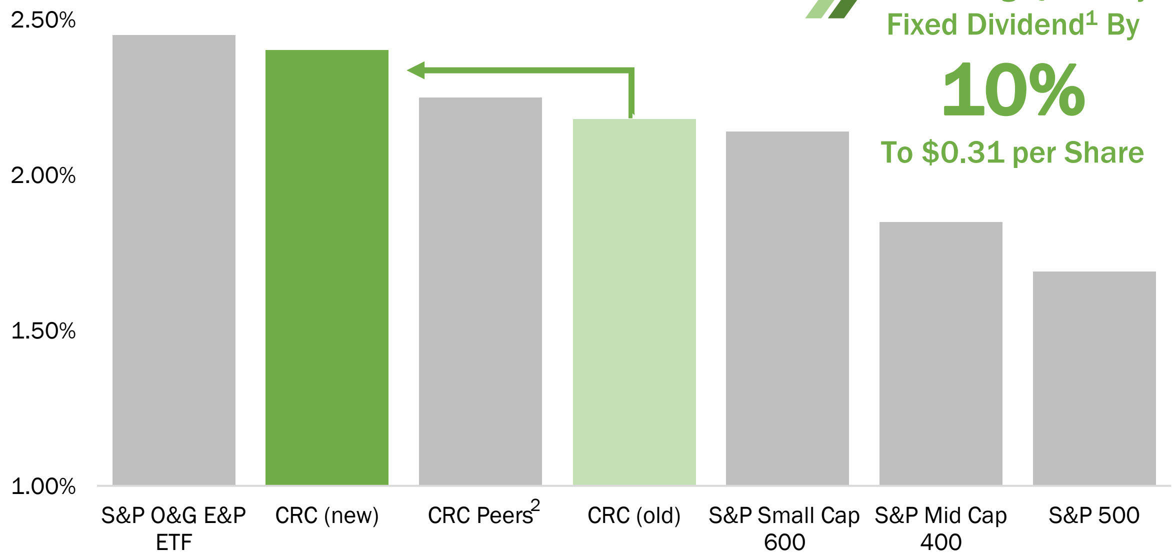
Above Average Fixed Return Yield vs. Market Participants & Peers

Existing $1.1B SRP with $497MM Remaining

Year to Date, Repurchased $35MM in Debt *(Including Post 3Q23 Repurchases)*

RAISING FIXED DIVIDEND FOR THE THIRD YEAR IN A ROW

Annualized Fixed Dividend yield (%)



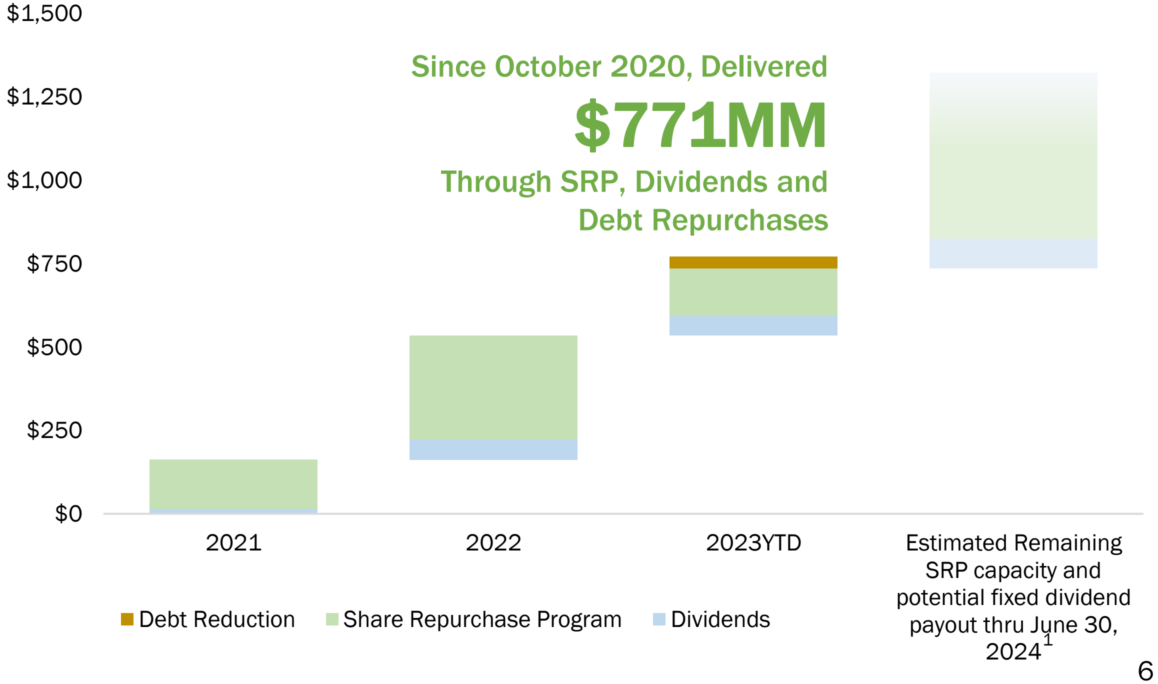
Increasing Quarterly Fixed Dividend[1] By

10%

To $0.31 per Share

CONTINUOUSLY CREATING VALUE FOR STAKEHOLDERS

Cumulative Amount Returned to Shareholders and Debt Repurchases ($MM)



Note: please see slide 30 for details on the footnotes on this slide.


CARBON
TERRAVAULT
THE FOREFRONT OF CARBON MANAGEMENT

Announcing CRC's First Capture to Storage Project at Elk Hills Gas Plant

A DIFFERENT KIND OF ENERGY COMPANY

DECARBONIZING CRC'S OPERATIONS & TARGETING

~6.5% REDUCTION[1] IN EMISSIONS INTENSITY OF ELK HILLS POWER PLANT

CTV'S FIRST CCS PROJECT TO CAPTURE AND STORE 100 KMTPA

PROJECT DETAILS FOR CAPTURE TO STORAGE PROJECT AT ELK HILLS

- CRC to construct a pre-combustion project at the CTV Clean Energy Park at Elk Hills to remove CO_2 from inlet gas, *increasing operational efficiency of the cryogenic gas processing plant, improving propane recovery, and reducing the carbon intensity of the electricity* generated from the Elk Hills Power Plant
- Expected to capture *100KMTPA of CO_2 and* to be stored at CTV I storage vault
- The capture project is targeting *45Q credit generation as well as the potential for LCFS qualification and Cap & Trade (C&T) avoidance,* and anticipates paying *CTV JV an injection fee for CO_2 sequestration services*
- *Project provides the ability to control the full CCS value chain*
  - CTV JV storage only economics are in line with previously disclosed type curve[2]
  - Capture + storage economics net to CRC are in line with previously disclosed IRR range[2] of 10% to 30%
- Project *FID targeted in 1H24[3]*; commercial *operations targeted in 2H25*

CO_2 INJECTION RATE (KMTPA)	✓	100 KMTPA (Planned)
PROJECT EST. CAPITAL REQUIREMENTS ($/MT)	✓	WITHIN OUR PREVIOUSLY DISCLOSED TYPE CURVE[2] OF $5 TO $15 OF CAPITAL PER MT OF CO_2 FOR A STORAGE-ONLY SOLUTION
PROJECT EST. EBITDA[4] ($/ MT)	✓	WITHIN OUR PREVIOUSLY DISCLOSED TYPE CURVE[2] OF $50 TO $75 OF EBITDA[4] PER MT OF CO_2 FOR A STORAGE-ONLY SOLUTION

Note: Due to CTV's 51% ownership of the storage entity, CTV JV, the metrics above are shown on a storage-only basis for comparison purposes to previously announced projects.

Note: please see slide 30 for details on the footnotes on this slide.

NLC Energy Greenfield Renewable Natural Gas (RNG) Facility

A DIFFERENT KIND OF ENERGY COMPANY

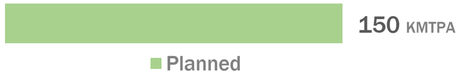
ABOUT NLC ENERGY

NLCenergy

- NLC Energy LLC, (NLCE) designs, builds, owns, and operates RNG facilities that convert organic waste into useful commodities like clean Renewable Natural Gas (RNG)
- Low-carbon RNG replaces higher-carbon fossil fuels across the transportation, utilities, and manufacturing sectors
- The company is headquartered in Nashua, NH and has an operational RNG plant in Denmark, WI

CDMA DETAILS FOR NLCE GREENFIELD RNG FACILITY[1]

- NLCE to construct a *greenfield production facility* at the CTV Clean Energy Park at Elk Hills that *is expected to generate up to 7,000 MMBtu per day of RNG*
- CTV JV will provide *permanent sequestration for 150KMTPA of CO_2 initially* using CTV I storage vault, including the lease of land for the *RNG* facility
- Project *FID targeted for late 2024*; commercial *operations targeted by 2027*
- CTV JV and NLC are also discussing *CRC's potential financial participation in the RNG facility*

CO_2 INJECTION RATE (KMTPA)	✓	
PROJECT EST. CAPITAL REQUIREMENTS ($/MT)	✓	WITHIN OUR PREVIOUSLY DISCLOSED TYPE CURVE[3] OF $5 TO $15 OF CAPITAL[2] PER MT OF CO_2 FOR A STORAGE-ONLY SOLUTION
PROJECT EST. EBITDA[2] ($/ MT)	✓	WITHIN OUR PREVIOUSLY DISCLOSED TYPE CURVE[3] OF $50 TO $75 OF EBITDA[2] PER MT OF CO_2 FOR A STORAGE-ONLY SOLUTION
OFFTAKE INTEREST	✓	RNG PRODUCTION OFFTAKE WITHIN THE CTV CLEAN ENERGY PARK AND CRC OPERATIONS COULD FURTHER REDUCE EXISTING AND FUTURE EMISSIONS OF FACILITIES

Note: please see slide 30 for details on the footnotes on this slide.

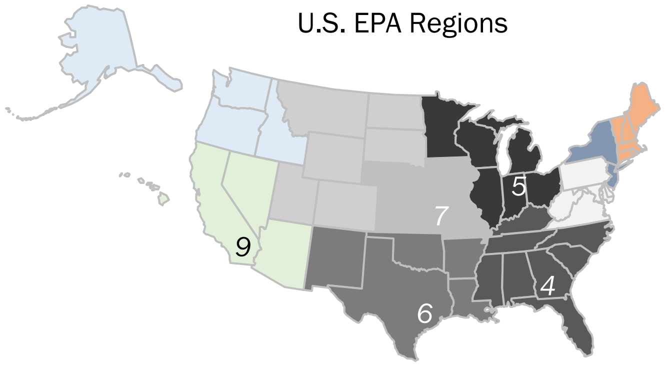
Solidifying CTV Class VI Permitting Leadership

A DIFFERENT KIND OF ENERGY COMPANY

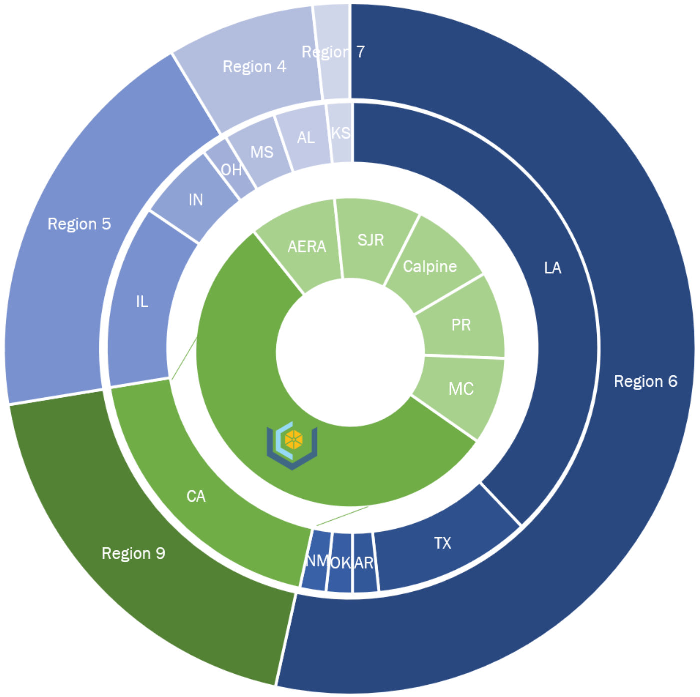
CTV Leads CA/Region 9 with EPA Class VI Permit Submissions

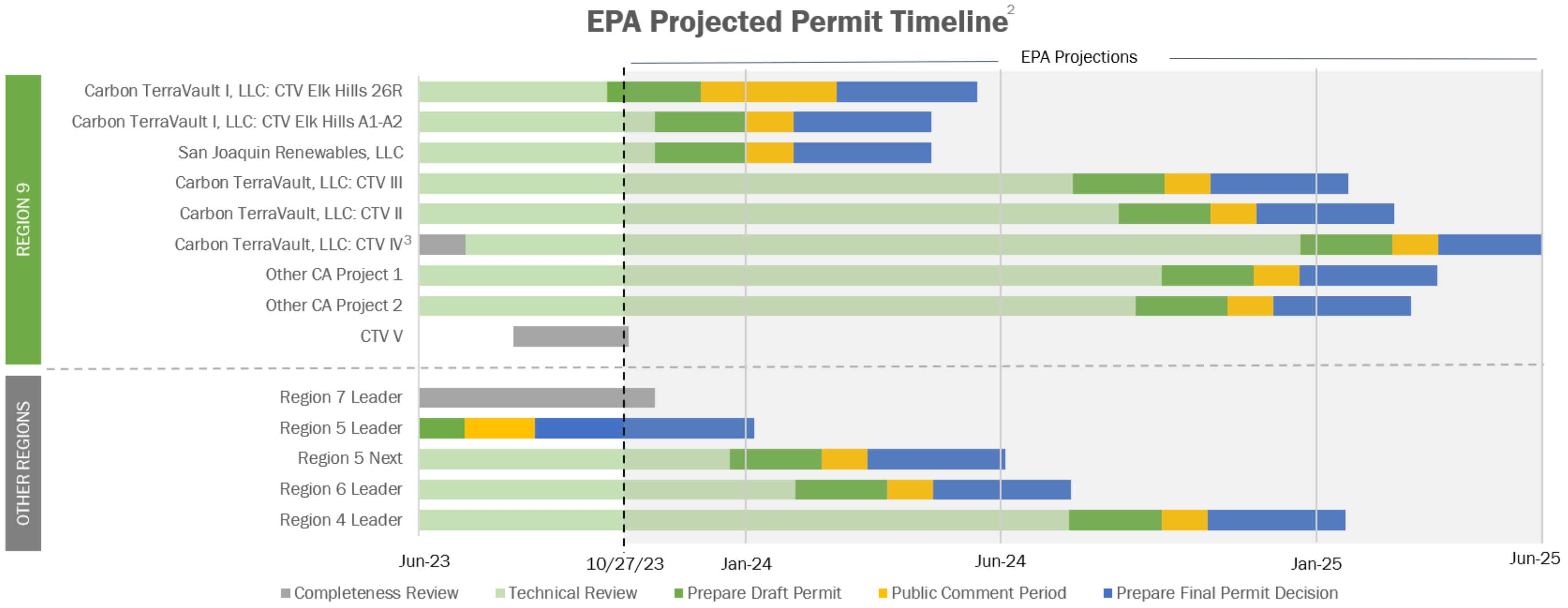
~10%

of Currently Submitted EPA Class VI Permits are From CTV[1]



- CTV Elk Hills 26R (CTV I) is expected to be receive draft permit before year end
- CTV Elk Hills 26R (CTV I) permit approval would be first in California and first permit for storage into a depleted oil and gas reservoir
- Proactively engaging with the local communities to share information about the positive benefits of these projects in the local communities





(1) Subject to issuance of EPA class VI permits. (2) Source: EPA Tracker, https://www.epa.gov/uic/current-class-vi-projects-under-review-epa,
(3) Projected to complete preparation of final permit decision at the end of June ‘25

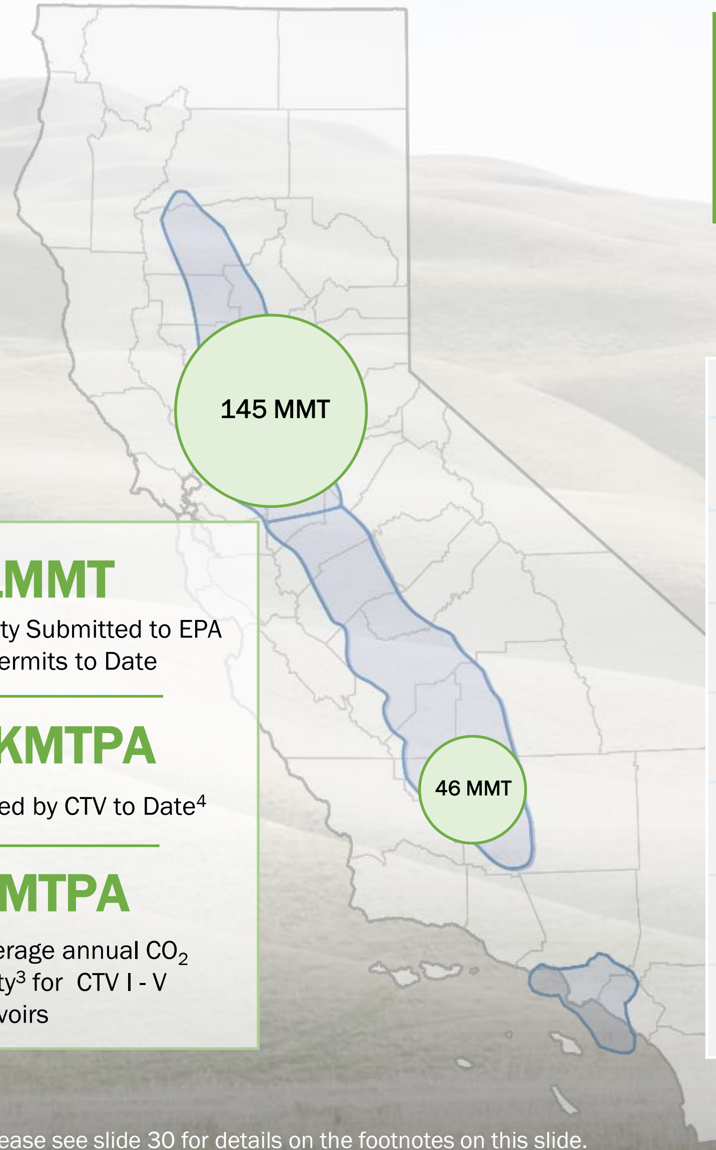
CARBON TERRAVAULT

Positioned to Be California's Premier Carbon Management Provider

100KMTPA for CRC's own CCS brownfield project within the CTV Clean Energy Park at Elk Hills

Signed an additional storage only CDMA[1] for an injection rate of 150KMTPA with NLC Energy

Targeting first CO_2 injection at CTV I by the end of 2025



191MMT

CTV Storage Capacity Submitted to EPA For Class VI Permits to Date

1,065KMTPA

of CDMAs Announced by CTV to Date[4]

4.8MMTPA

Est. combined average annual CO_2 injection capacity[3] for CTV I - V reservoirs

Vault	CTV I	CTV II	CTV III	CTV IV	CTV V
EPA Permit Application Administratively Complete	Yes	Yes	Yes	Yes	In Progress
Targeting Class VI Draft EPA Permit Receipt	~YE23	~2024	~2024	~2025	~2025
California's Basin	SJ Basin	Sacramento Basin			
Annual Regional CO_2 Emissions[2] *(MMTPA)*	~30	~60			
Est. Average Annual Injection Capacity[3] *(MMTPA)*	~1.2	~0.6	~1.8	~0.9	~0.4
Potential Total Storage Capacity *(MMT)*	46	23	71	34	17
Remaining and Available CO_2 Injection Capacity (%)[5]	43%	100%	~77%	100%	100%

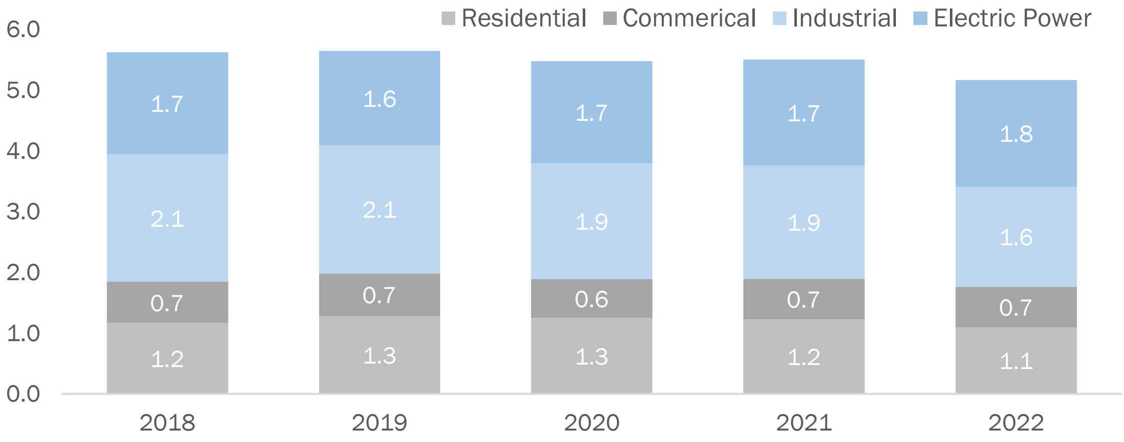
Note: please see slide 30 for details on the footnotes on this slide.

California

California Needs Low Carbon Intensity Domestic Natural Gas

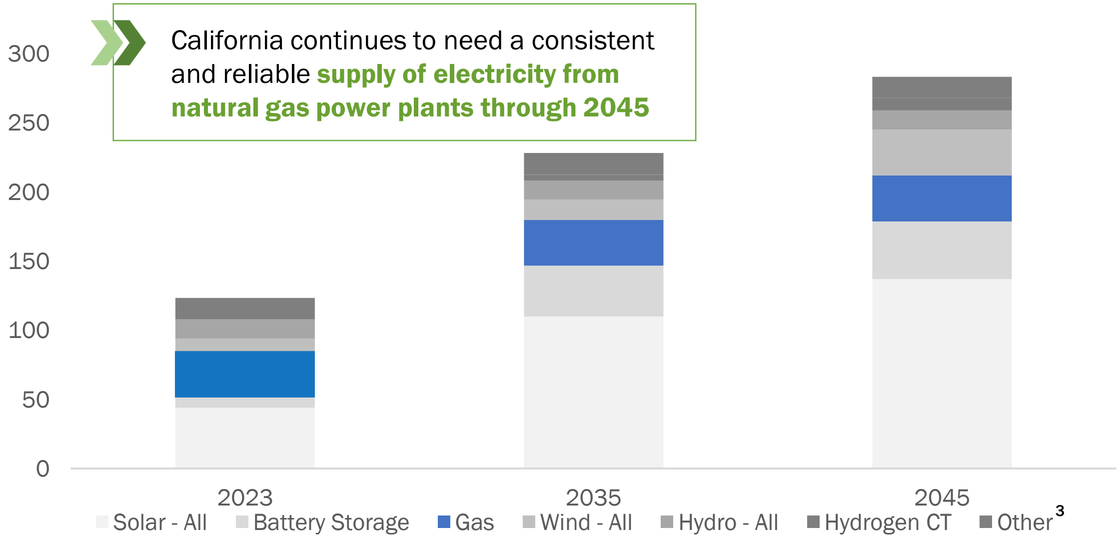
POWER AND INDUSTRY CONSUME ~70% OF THE STATE'S NATURAL GAS[1]

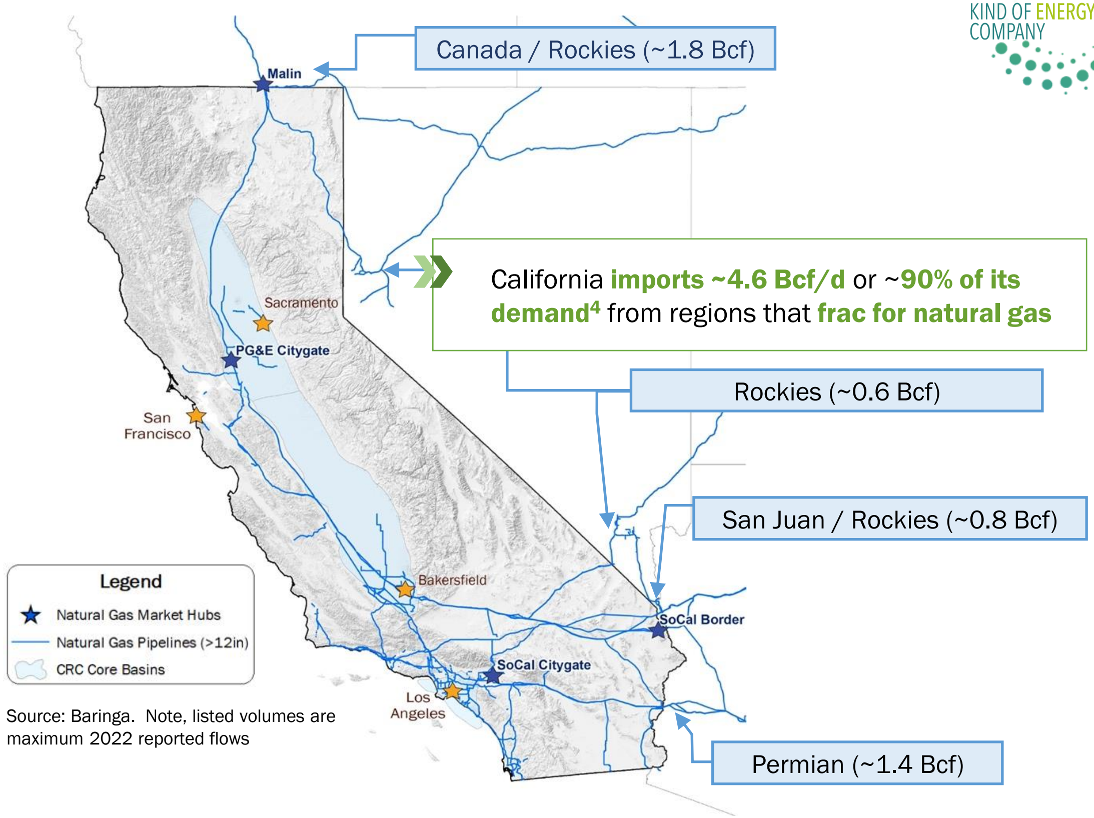
California's Natural Gas Demand (Bcf/d)



EVEN IN 2045, NATURAL GAS POWER PLANTS PLAN TO CONTRIBUTE 12%[2]

Total Capacity (Giga-watts)





Source: Baringa. Note, listed volumes are maximum 2022 reported flows

California Will Continue to Receive a Premium to Henry Hub

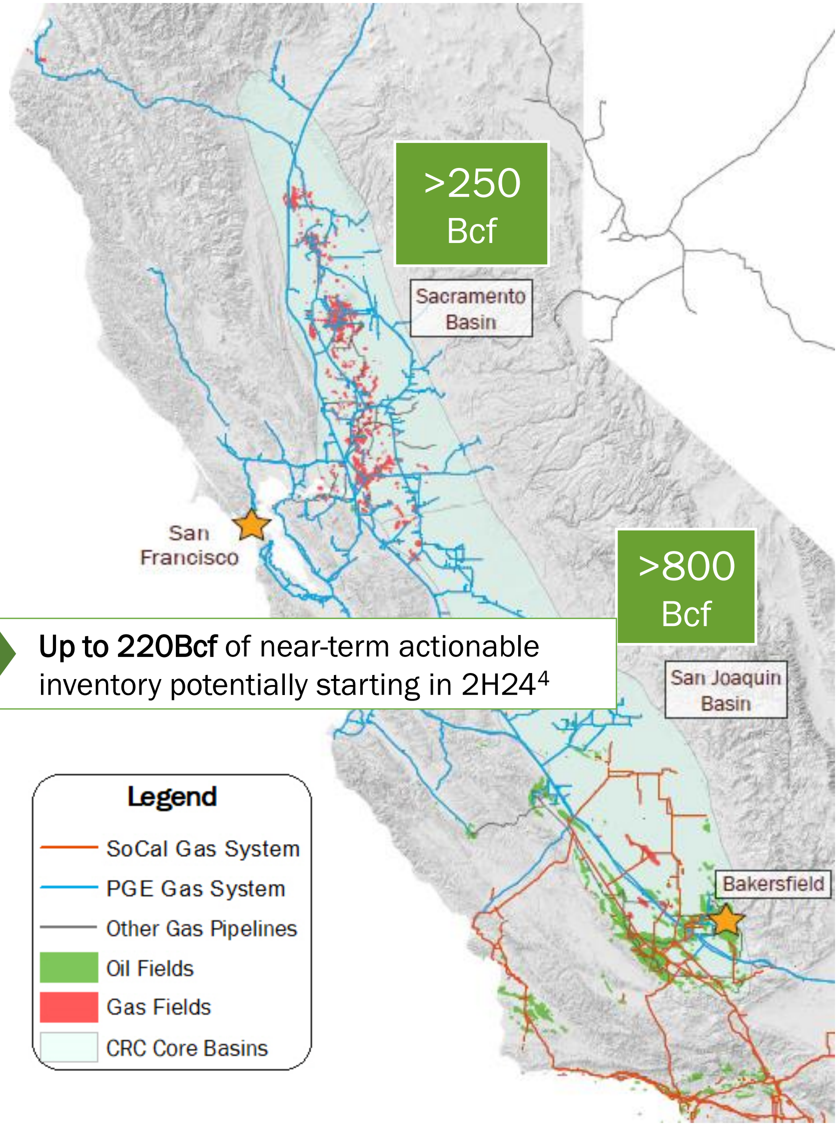
- CRC expects natural gas to play a key role in supporting energy transition
- **CA imports 90% of its gas needs**. Lack of flexibility with the legacy natural gas infrastructure will continue to drive elevated prices and volatility in periods of high demand[5]
- **CRC expects relatively strong natural gas prices with the premium to Henry Hub to continue**

(1) EIA; excludes Vehicle Fuel which was less than 0.029 mcf/d from 2018 to 2022 (2) CARB Scoping Plan 2022 (3) Other includes pumped storage, shed DR, geothermal, nuclear, biomass, CHP and coal (4) CARB (5) Internal estimates

CRC's Natural Gas Inventory Depth – 1Tcf[1] Opportunity

A DIFFERENT KIND OF ENERGY COMPANY

CRC's Incremental Inventory[1] by Basin



Up to 220Bcf of near-term actionable inventory potentially starting in 2H24[4]

CRC is pursuing a **Responsibly Sourced Gas[2] (RSG)** certification for the majority of its natural gas assets

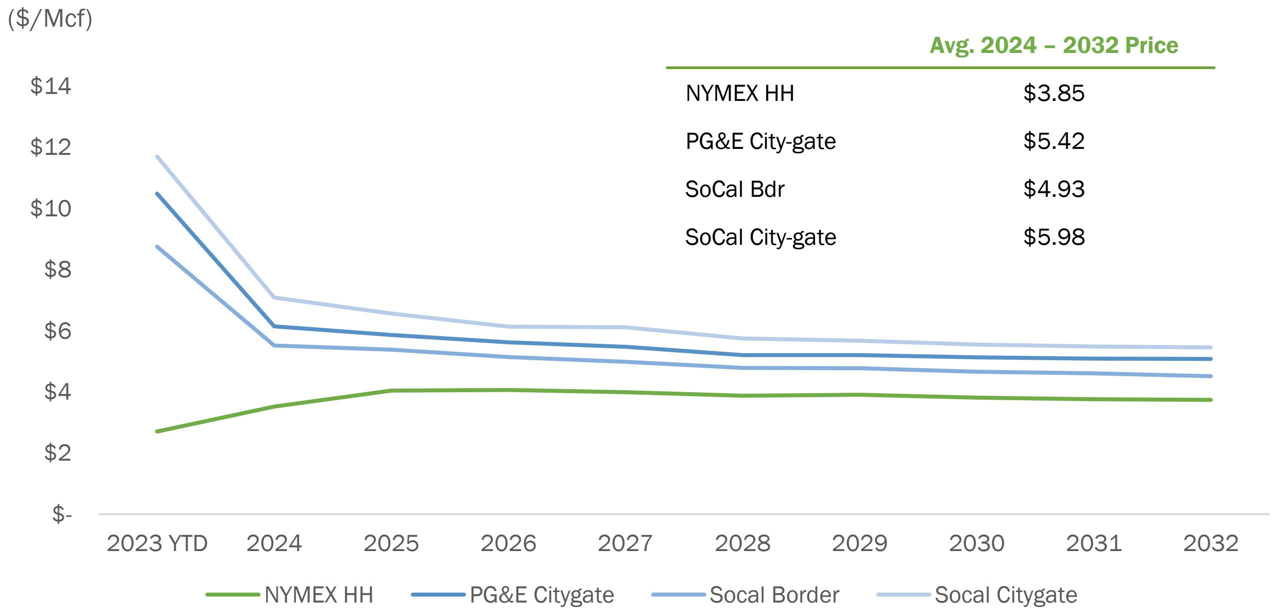
Sacramento Basin Incremental Inventory[1]

- ~110Bcf of actionable inventory
- Resource:
  - >250 Bcf of dry gas
  - ~300 locations

San Joaquin Basin Incremental Inventory[1]

- ~700Bcf of actionable inventory
- Resource:
  - >800 Bcf of associated gas
  - ~1,100 locations

CALIFORNIA'S NATURAL GAS FORWARD CURVES[3]



	Avg. 2024 – 2032 Price
NYMEX HH	$3.85
PG&E City-gate	$5.42
SoCal Bdr	$4.93
SoCal City-gate	$5.98

Note: please see slide 31 for details on the footnotes on this slide.

Preliminary 2024 E&P Business Outlook

A DIFFERENT KIND OF ENERGY COMPANY

LINE OF SIGHT TO WELL PERMITTING PROGRESSION IN **2024**

EXPECTED INVENTORY OF SIDETRACKS, WORKOVERS, NATURAL GAS TO INCREASE ACTIVITY IN 2H24

CONTRACTED CAPACITY REVENUE[1] FROM EHPP TO INCREASE BY

~$45MM

IN 2024 VS 2023E

ON PATH TO ACHIEVE

$55MM +

IN TARGETED YE2023 RUN RATE REDUCTIONS[2]
IMPLIES ~$2/BOE REDUCTION TO CRC'S OPERATING COST[3]

EST. ELK HILLS PLANTS TURNAROUND IMPACT IN 1Q24

20 MMCF/D	**$34MM** CAPITAL

(1) Capacity revenue is a part of electricity revenue on CRC's income statement. (2) Includes YE2023 reduction in non energy operating costs and Adj. E&P corporate and other G&A. (3) Internal estimates.

4Q23 Guidance

2023E Corporate Guidance *(as of November 1st, 2023)*

CRC 2023E GUIDANCE[1]:	FY 2023E E&P, Corp. & Other	FY 2023E CMB	FY23E Combined	4Q23E E&P, Corp. & Other	4Q23E CMB	4Q23E Combined
Net Total Production[1] (MBOE/D)	**85 – 87**	—	85 – 87	**82 – 85**	—	82 – 85
Net Oil Production[1] (MBO/D)	**51 – 53**	—	51 – 53	**49 – 51**	—	49 – 51
Operating Costs ($MM)	**$815 – $850**	—	$815 – $850	**$185 – $195**	—	$185 – $195
CMB Expenses[2] ($MM)	—	$40 - $50	$40 - $50	—	$10 - $20	$10 - $20
Adj. G&A[3] ($MM)	**$185 – $210**	$10 - $15	$195 – $225	**$50 – $56**	$1 - $2	$51 – $58
Total Capital ($MM)	—	—	$185 - $210	—	—	$65 - $81
Adj. Total Capital[4] ($MM)	**$180– $200**	$5 - $10	—	**$60 – $71**	$5 - $10	—
Free Cash Flow[3] ($MM)	**$470 – $510**	($70) – ($90)	$380 - $440	**$50 - $75**	($45) – ($55)	($5) - $30

Includes:
~$20MM in new CMB land purchases /easements

Other Guidance Items:	FY 2023E Low	FY 2023E High	4Q23E Low	4Q23E High
Marketing of Natural Gas Margin ($MM)	$155	$185	$20	$30
Electricity Margin ($MM)	$80	$110	$10	$15
Transportation Expense ($MM)	$60	$80	$15	$19
ARO Settlement Payments ($MM)	$55	$60	$10	$12
Taxes Other Than on Income ($MM)	$170	$180	$40	$44
Interest and Debt Expense ($MM)	$55	$60	$13	$15
Cash Income Taxes ($MM)	$100	$120	$25	$35
Commodity Realizations:				
Oil - % of Brent:	94%	97%	96%	99%
NGL - % of Brent:	56%	60%	50%	60%
Natural Gas - % of NYMEX:	275%	325%	165%	185%

2023E Guidance Assumptions
($/Bbl)
2023E Brent Price: $84.16
4Q23E Brent Price: $90.46

Note: please see slide 31 for details on the footnotes on this slide. Current 2023 guidance doesn't include targeted cost reduction initiatives mentioned on page 15 of this deck.

Appendix

Why California Resources Corporation?

A DIFFERENT KIND OF ENERGY COMPANY

CALIFORNIA RESOURCES CORPORATION | CARBON TERRAVAULT | full SCOPE net ZERO 2045

LEADING CARBON MANAGEMENT BUSINESS

PREMIER BALANCE SHEET WITH STRONG FREE CASH FLOW GENERATION

STRONG SHAREHOLDER RETURNS STRATEGY

DISCIPLINED CAPITAL ALLOCATION

Executing on our Low Carbon Intensity O&G Operations

A DIFFERENT KIND OF ENERGY COMPANY

Key Operational Results:

85MBOED
3Q23 NET PRODUCTION

Oil | NGLs | Gas
60% | 13% | 27%

$33MM
3Q23 E&P, CORP, & OTHER ADJ. CAPITAL[1]

D&C and Workovers | Facilities | Corporate & Other
73% | 21% | 6%

$212MM
3Q23 OPERATING & TRANSPORTATION COSTS

Non-Energy Operating Costs[2] | Energy Operating Costs | Transportation
57% | 35% | 8%

3Q23 OPERATIONAL PERFORMANCE COMMENTARY:

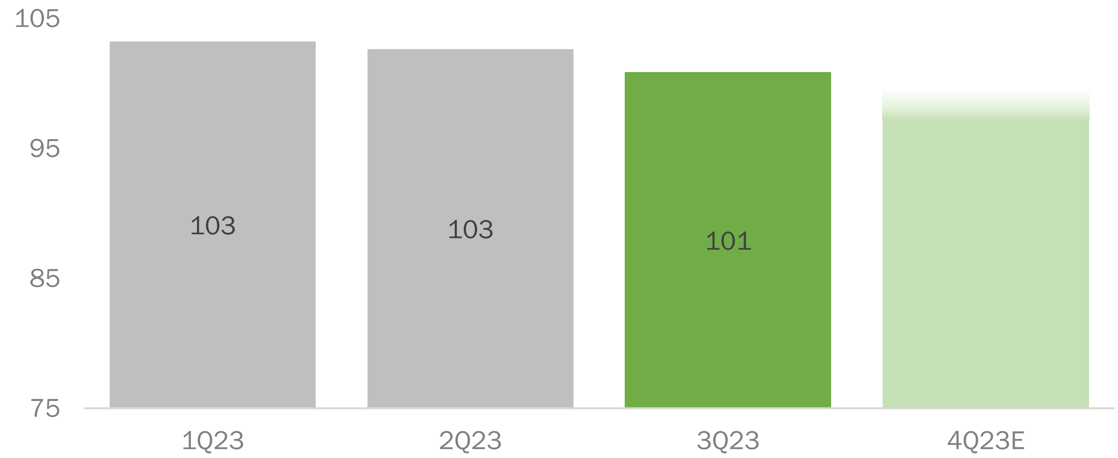
- Continue strong HSE performance above internal goals
- Wells: Drilled[3] 9 wells in 3Q23
- Rig Activity: Exited the quarter with 1 drilling rig in the LA basin and 34 maintenance rigs across CRC's asset base

3Q23 PRODUCTION PERFORMANCE COMMENTARY:

- PSC Effects: On a net basis, higher than anticipated Brent prices resulted in a negative quarterly 1.2MBOED of net oil production impact due to PSC effects
- Higher oil prices contributed ~$7MM of higher than planned operating cash flow[4]
- Targeting gross production annual decline rate in line with previously provided 5% to 7% range

RESILIENT ASSET BASE DESPITE LIMITED CAPITAL INVESTMENT

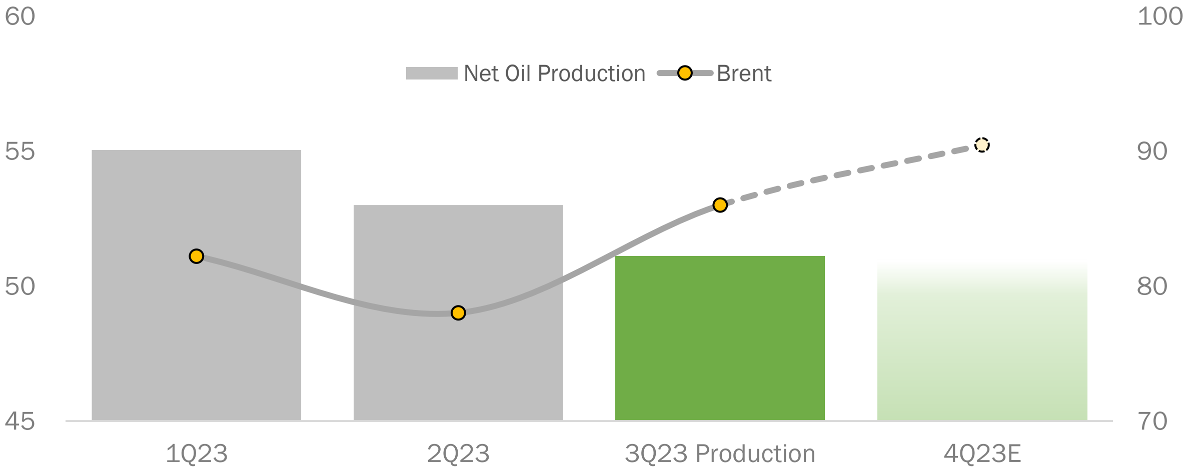
Average Gross Total Production Per Day (MBOEPD)



CRC'S NET OIL PRODUCTION

Average Net Oil Production Per Day (MBOPD)

Average Quarterly Brent Price ($/bbl)



(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) Non-Energy Operating Costs includes gas processing costs. (3) Includes steam injectors and drilled but uncompleted wells, which are not included in the SEC definition of wells drilled. (4) Impact to cash flow after hedges and before changes in working capital.

Wilmington Production Sharing Contracts (PSC) At Higher Commodity Prices

For every $1/BBL increase/decrease in Brent price, we expect a ~90BOD decrease/increase in our net oil production related to PSCs[1]

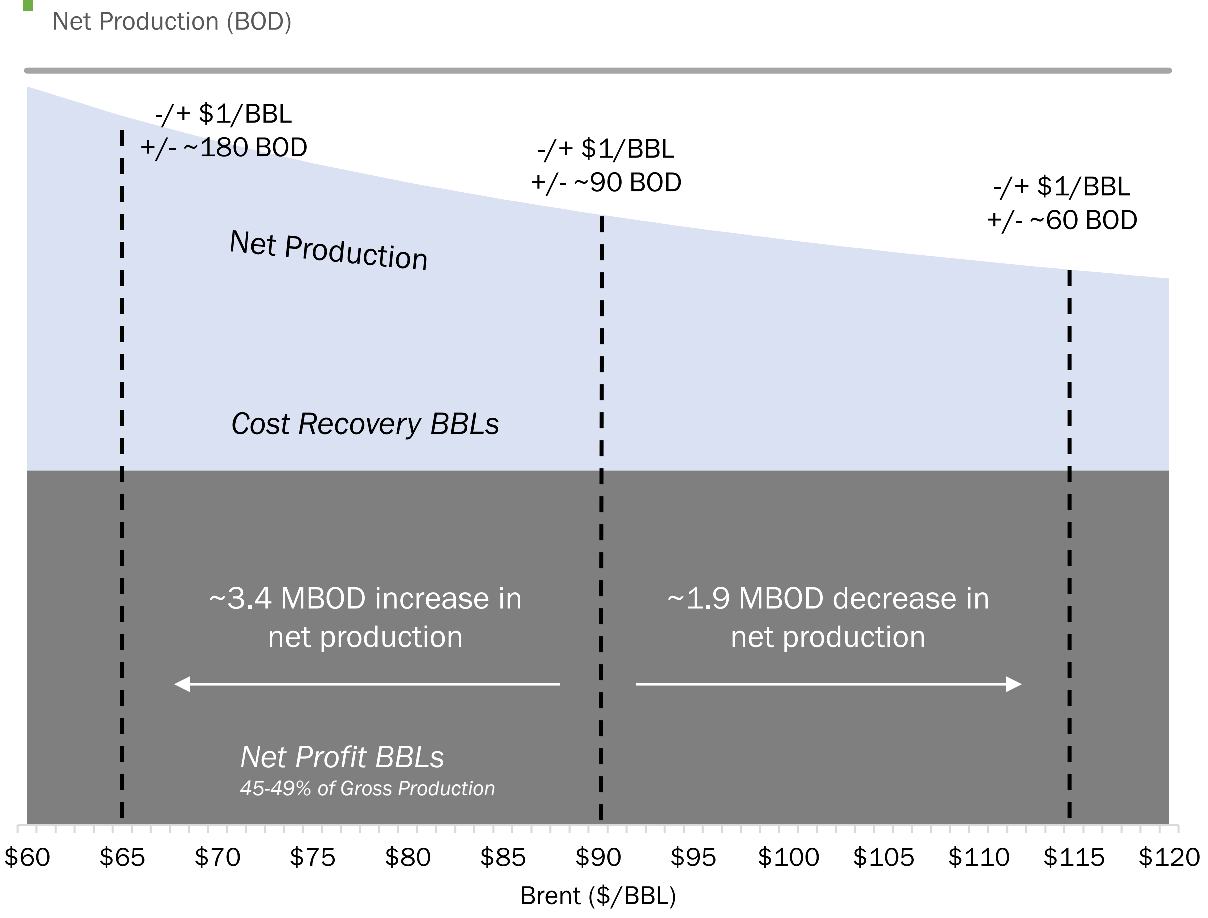
Approximately 30% of CRC's oil production is subject to PSCs Mechanics:

- As operator, CRC pays our partners' share of the Operating and Capital Cost
- CRC recovers our partners' share of operating and capital costs through production sharing, where CRC's cost recovery is reported as revenue
- CRC receives 45-49% of the gross production as "Profit Barrels" after cost recovery
- CRC's net share of production includes cost recovery and profit barrels

As prices rise, fewer barrels are required to recover our partners' portion of the cost

CRC sees a difference of ~5.3MBOD in net oil production between $65/BBL and $115/BBL

EFFECT OF OIL PRICE ON NET PRODUCTION[2]



(1) Based on Brent price of $90 per barrel of oil (2) Net Production from Wilmington field only. Includes the effects of a development program in LA Basin.

Huntington Beach – Asset Optimization & Value Unlock

A DIFFERENT KIND OF ENERGY COMPANY

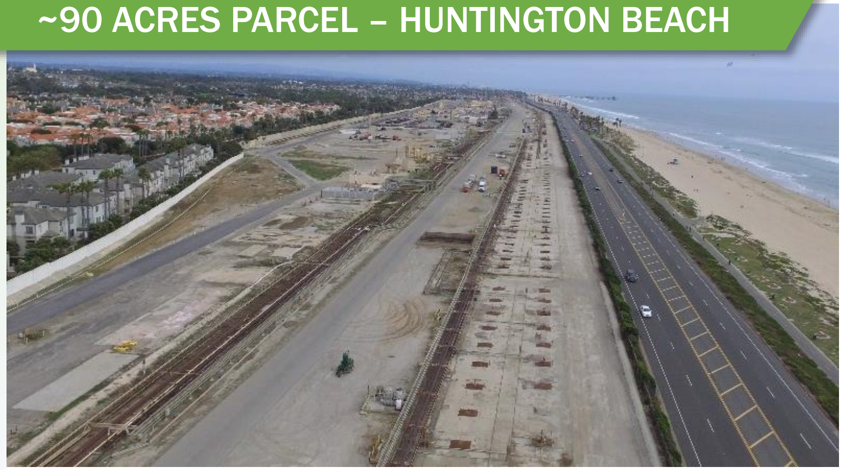
1 ACRE PARCEL – FT APACHE

Source: Newmark

- 1810 Pacific Coast Highway, Huntington Beach, CA
- Completed the abandonment of six wells
- In the process of completing surface abandonment
- Targeting call for offers for ~1 acre parcel of land (Fort Apache) by YE23

Over 1 mile of direct access to **Pacific Coast Highway**

~90 ACRES PARCEL – HUNTINGTON BEACH



- Continuing the re-zoning, re-entitlements and due diligence processes
  - Multi year process
- Developing strategy to optimize production and ARO schedule
  - Huntington Beach field 2022 gross production[1] was ~3,000BOD
  - The field is connected to a producing offshore platform Emmy
  - Free cash flow[2] generating asset
- Plugged and abandoned 20 wells year to date
- Targeting to P&A an additional 40 wells in 2024

Source: CRC. (1) Source: CalGEM (2) 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. Free cash flow is equal to operating cash flow less total capital requirements.

Multiples Paths to Decarbonize

A DIFFERENT KIND OF ENERGY COMPANY

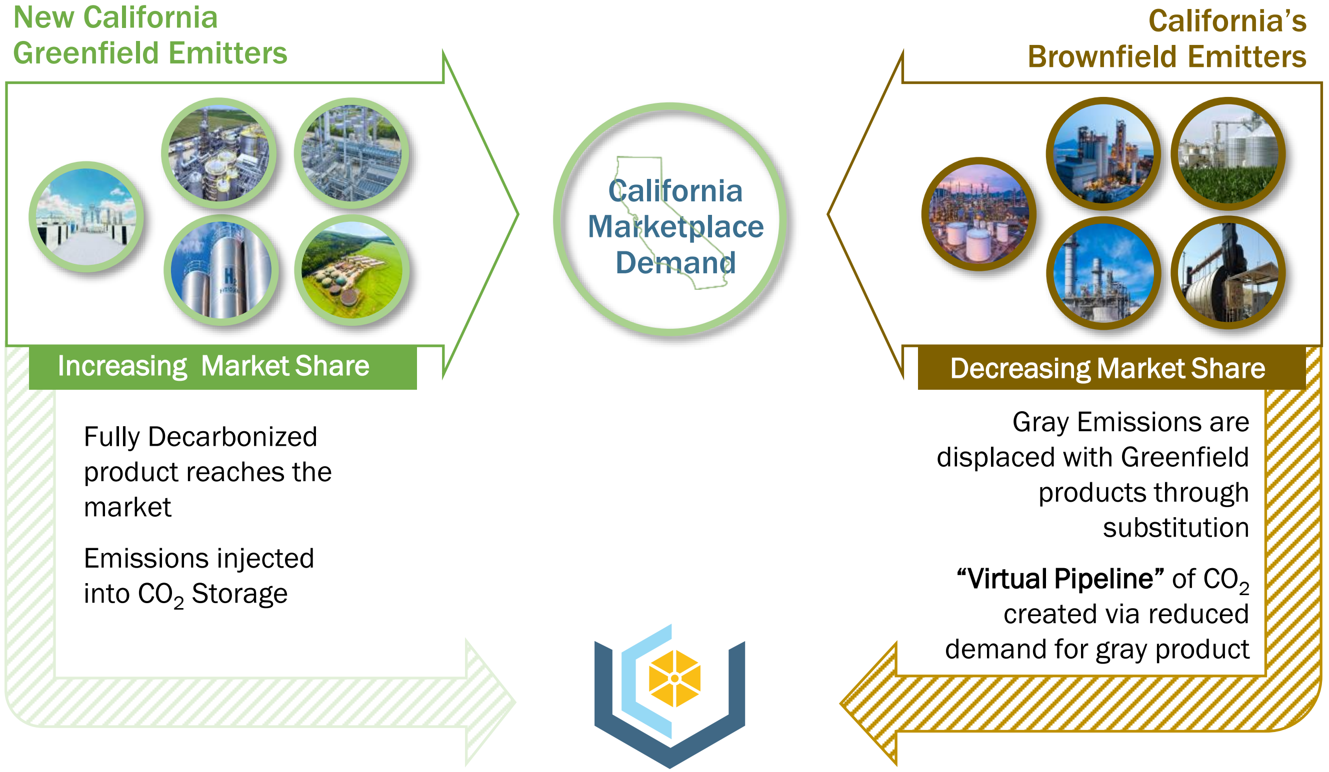
Conventional Brownfield CCS

- Brownfield emitters provide a decarbonized product by capturing the CO_2 molecules used in the creation of their products and transporting CO_2 for permanent storage
- This lowers the carbon intensity of their product and the brownfield takes the decarbonized product to market
- Decarbonization enabled by emissions which are transported by physical pipe

Greenfield CCS

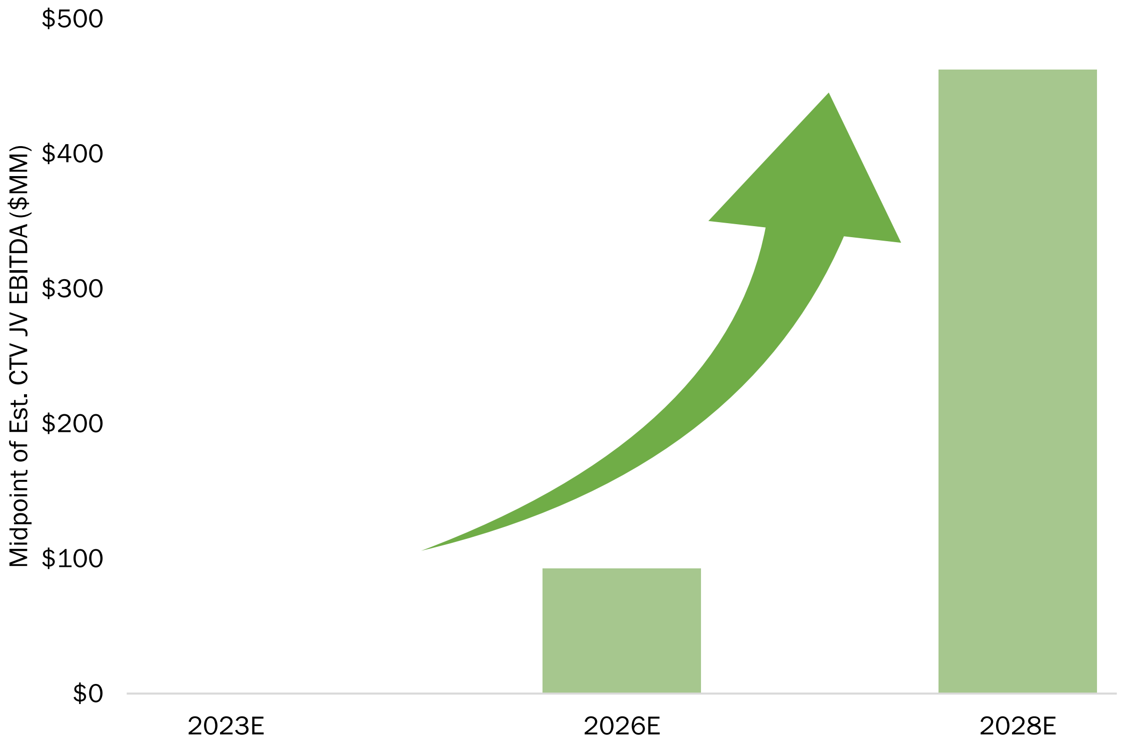
- Greenfield projects provide product with an inherently lower carbon intensity than gray products
- Greenfield decarbonized product acts as a substitute for gray product and captures market share
- Decarbonization occurs via products which displace higher CI products thus creating a **"Virtual Pipeline"** that takes lower CI products to market rather than taking the CO_2 from gray products

CRC can either help decarbonization efforts by taking **CO_2 emissions from gray products** or by enabling newer green products to displace gray emissions by taking **market share**



Illustrative CTV JV Type Curve Demonstrates Potential Valuation Upside

A DIFFERENT KIND OF ENERGY COMPANY



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

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

EXAMPLE CTV JV PROJECT ECONOMICS – "TYPE CURVE"

(PER MT OF INJECTED CO_2)

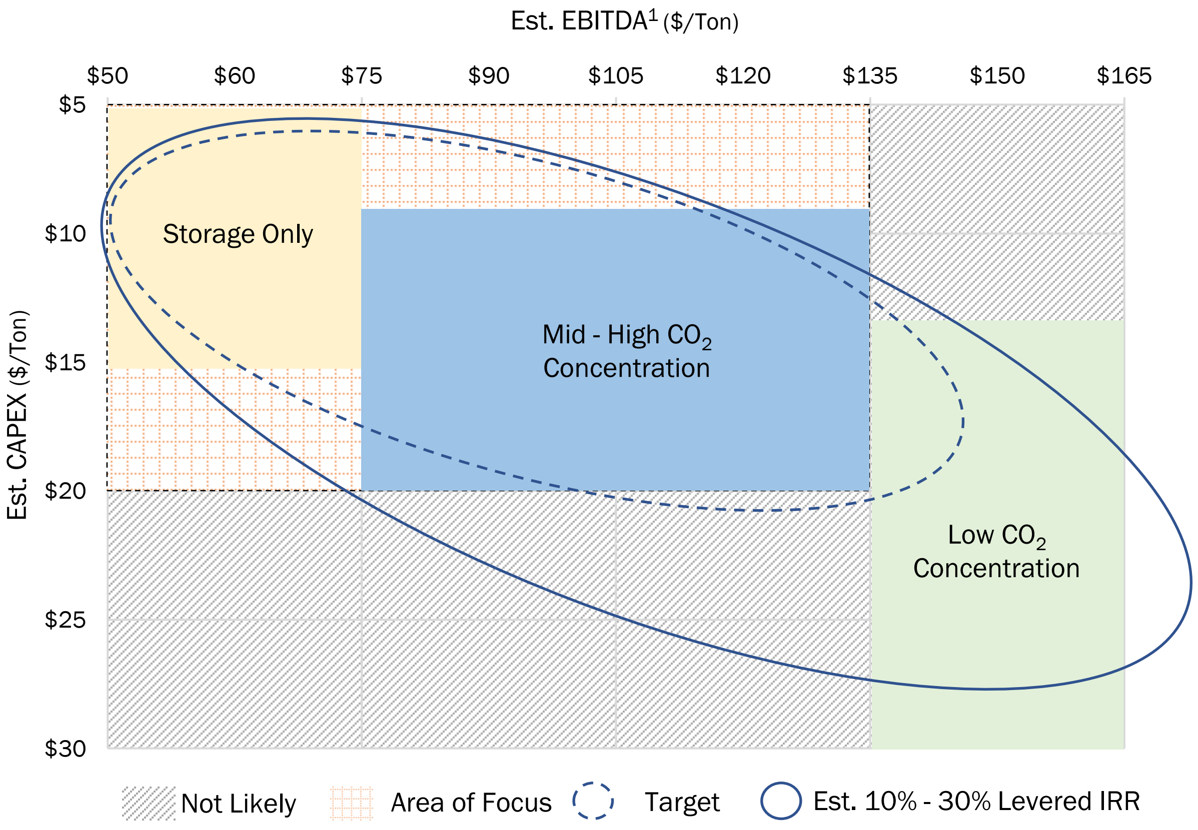
	Unit	Low	High	Notes/Incorporated Assumptions
Total Incentive Potential (LCFS + 45Q)	$/MT	$170	$205	45Q ($/MT): $85, LCFS ($/MT): $85 - $120, 100% LCFS eligibility
Opex	$/MT	$10	$75	Range reflects costs associated with full range of business model possibilities and includes G&A of dedicated staff.
Capex	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: Please see Slide 31 for important information regarding the assumptions used in the preparation of the information show on this slide. CTV JV economics are shared 51% to CRC and 49% to Brookfield. EBITDA is a non-GAAP measure.

Large Opportunity Set With a Variety of Potential Emitters

A DIFFERENT KIND OF ENERGY COMPANY

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 and estimated IRR, EBITDA and capital expenditure requirements based on internal estimates. Actual results could differ materially. (1) EBITDA is a non-GAAP measure. EBITDA estimates include 45Q tax credits which may change based on further guidance from IRS and other factors and assumes that 45Q wage and apprenticeship requirements are met. (2) CalCapture refers to CRC's project at the Elk Hills Power Plant.

Strong Price Realizations in CA's Unique Market Dynamics

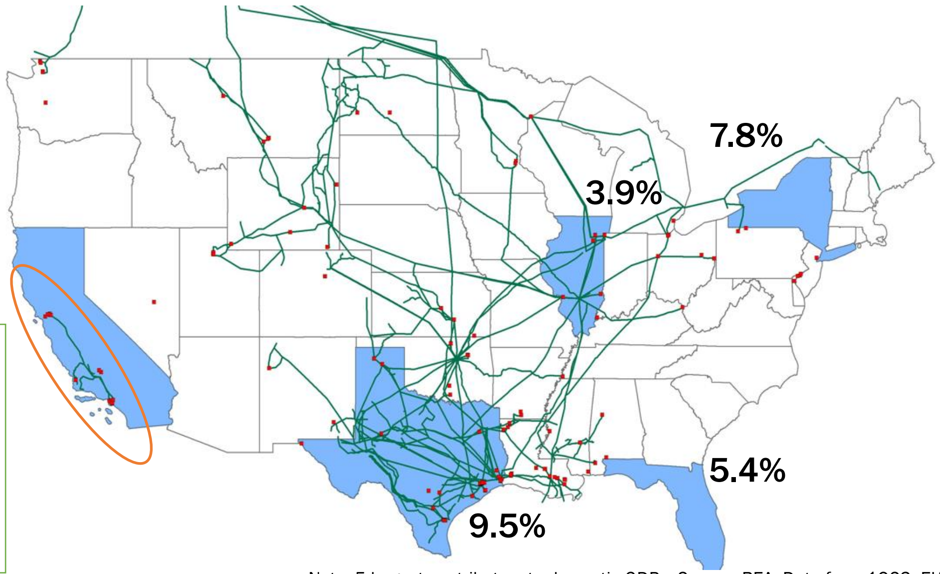
A DIFFERENT KIND OF ENERGY COMPANY

- **Crude:** California crude prices continued move in tandem with the broader market with realizations for 3Q23 firming slightly from 2Q. For the balance of the year, local (permits, refining margins & outages) and geopolitical dynamics (OPEC+, central bank policies, Middle East tensions) remain key determinants as to where prices will trend in California
- **NGLs:** 3Q23 NGL prices across North America continued to weaken driven by seasonal trend and general over-supply. As reflected within 2Q23 realizations - and as projected for the balance of the year - California has been and should remain a premium-priced NGL marketplace
- **Natural Gas:** California 3Q23 natural gas prices increased relative to 2Q23 as storage inventories were replenished. A material increase in Aliso Canyon natural gas storage capacity stands to support prices this Fall while – along with an abundance of hydro generation capacity - limiting the potential for gas price run-ups this winter
- **Power:** As measured on year/year basis, 3Q power prices retreated on the back of record snowpack & hydro output, incremental on-peak solar output, and uncharacteristically mild weather

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

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

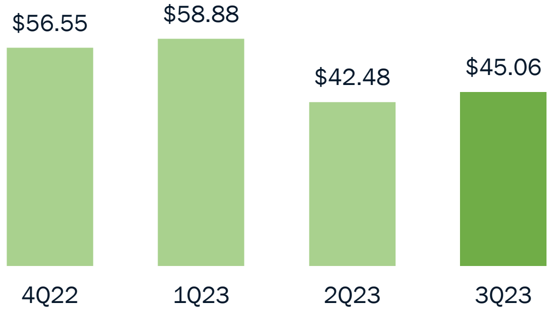
(amounts shown as % of U.S. domestic GDP)



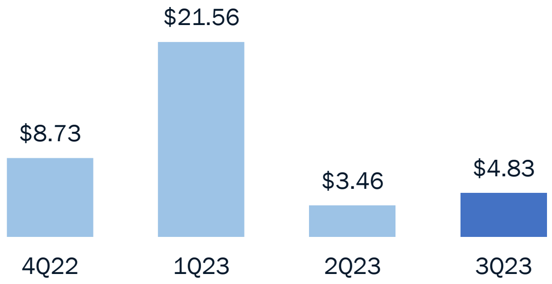
Note: 5 largest contributors to domestic GDP. Source: BEA, Data from 1Q23; EIA

Oil w/ Hedges ($/BBL)

NGLs ($/BBL)



Natural Gas ($/MCF)



	Oil 4Q22	Oil 1Q23	Oil 2Q23	Oil 3Q23	NGLs 4Q22	NGLs 1Q23	NGLs 2Q23	NGLs 3Q23	Gas 4Q22	Gas 1Q23	Gas 2Q23	Gas 3Q23
Average Benchmark Prices[1]	$88.60	$82.22	$78.01	$85.95	$88.60	$82.22	$78.01	$85.95	$6.76	$3.42	$2.10	$2.55
% of Benchmark[1]	98%	96%	97%	99%	64%	72%	54%	52%	129%	630%	165%	189%
Hedge Settlements	($25.82)	($15.64)	($12.11)	($19.24)	–	-	-	-	($0.22)	-	-	-
Average Realized Prices[2]	$61.33	$63.04	$63.66	$66.12	$56.55	$58.88	$42.48	$44.95	$8.51	$21.56	$3.46	$4.83

(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.

Hedging Program

A DIFFERENT KIND OF ENERGY COMPANY

STRATEGY

CRC's hedging strategy is designed **to meet our business objectives should market prices decline and participate should market prices increase**

2024 CRUDE REVENUE NET HEDGE SETTLEMENT SENSITIVITY TO BRENT PRICE [1]

($MM)

CRC Realized Price ($/bbl)	$60	$63	$65	$71	$79	$88	$91	$94	$97

OIL HEDGES[2]

As of September 30, 2023

		4Q23	1Q24	2Q24	3Q24	4Q24	2025
SOLD CALLS	Barrels per Day	5,747	23,650	30,000	30,000	29,000	19,748
	Weighted-Average Price per Barrel	$57.06	$90.00	$90.07	$90.07	$90.07	$85.63
SWAPS	Barrels per Day	27,094	9,000	7,750	7,750	5,500	3,374
	Weighted-Average Price per Barrel	$70.73	$79.37	$79.65	$79.64	$77.45	$72.66
NET PURCHASED PUTS[3]	Barrels per Day	5,747	30,584	30,000	30,000	29,000	19,748
	Weighted-Average Price per Barrel	$76.25	$67.27	$65.17	$65.17	$65.17	$60.00

HEDGE CONTRACT SETTLEMENTS EXPECTED TO SIGNIFICANTLY DECREASE IN 4Q23[4] AND BEYOND

Actual & Estimated Hedge Contract Settlements[5] ($MM)

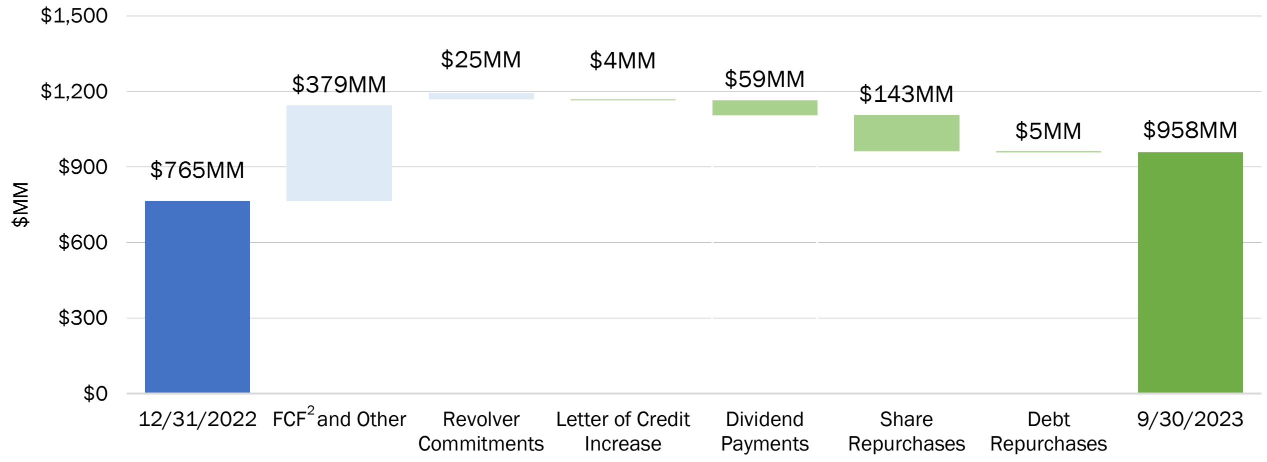
2021	2022	1Q23	2Q23	3Q23	4Q23E	2023E	2024E	2025E
($319)	($738)	($65)	($63)	($95)	($75)	($300)	($35)	($20)

(1) Hedge position as of September 30, 2023. Includes deferred option premium payment. For the purposes of this example assumes CRC physical sales realize 100% of Brent price. (2) Hedges are based on weighted-average Brent prices per barrel. (3) Purchased and sold puts with the same strike price have been netted together. (4) Assumes forward commodity prices as of September 30, 2023 and assumes a 2023 Brent price of $84.16 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $2.77 per mcf. (5) Represents estimated net cash settlement payments for derivative contracts as of 9/30/2023, except 2021, 2022, 1Q23, 2Q23 and 3Q23 which are actuals for the year ended on December 31, 2021, the year ended December 31, 2022, the three months ended March 31, 2023, the three months ended June 30, 2023, and the three months ended September 30, 2023 respectively. Historical settlements include natural gas derivatives on production volumes.

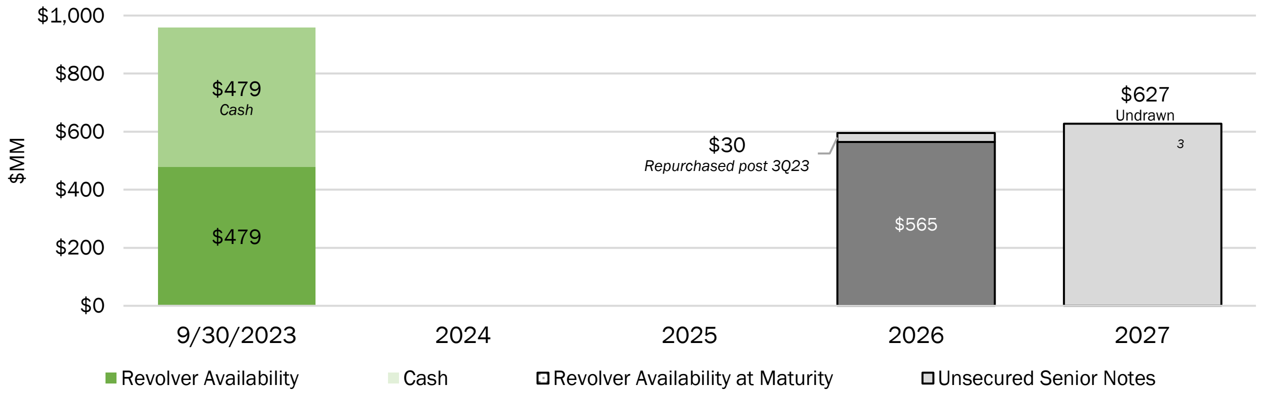
Strong Balance Sheet Position, Ample Liquidity and Financial Flexibility

A DIFFERENT KIND OF ENERGY COMPANY

LIQUIDITY ROLL BACK[1]



NO SIGNIFICANT MATURITIES UNTIL 2026



9/30/23 NET DEBT[2] SNAPSHOT

($MM)	
Revolving Credit Facility (RCF)[3]	$ 0
7.125% Senior Notes	595
Face Value of Debt	**$ 595**
Less Cash & Cash Equivalents	(479)
Net Debt[3]	**$ 116**

RECENT CREDIT UPDATES

- Repurchased $5MM of senior notes at par during 3Q23
- Subsequent to quarter end, repurchased an additional $30MM in face value of our senior notes
- S&P Global reaffirmed CRC's 'B+' rating on strong financial metrics and stable outlook despite lower production

MULTIPLES DEMONSTRATE FLEXIBILITY

($MM)	
RCF Borrowing Base	$ 1,200
3Q23 Free Cash Flow[2]	$71
3Q23 Net Debt[2] / LTM Adjusted EBITDAX[2]	0.1x
LTM Adjusted EBITDAX[2] / LTM Interest & Debt Expense, net	15.6x

(1) Liquidity at 9/30/23 calculated as unrestricted cash of $479MM and $627MM capacity on CRC's Revolving Credit Facility less $148MM in outstanding letters of credit. (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. (3) Undrawn RCF as of September 30, 2023, excluding outstanding letters of credit. Subject to a springing maturity to August 4, 2025, if any of our Senior Notes are outstanding on that date.

Glossary

A DIFFERENT KIND OF ENERGY COMPANY

Term	Definition
Bcf	Billion Cubic Feet
BMT	Billion Metric Tons
CARB	California Air Resources Board
CCS	Carbon Capture and Storage
CCS+	Carbon Capture and Storage + EOR
CDMA	Carbon Dioxide Management Agreement
CEQA	California Environmental Quality Act
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
EHPP	Elk Hills Power Plant
EIR	Environmental Impact Report
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
ESG	Environmental, Social and Governance
FCF	Free Cash Flow
FEED	Front End Engineering and Design

Term	Definition
FID	Final Investment Decision
GHG	Greenhouse Gas
IRR	Internal Rate of Return
KMTPA	Thousand Metric Tons Per Annum
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
OCF	Operating Cash Flow
PD	Proved Developed
PUD	Proved Undeveloped
RSG	Responsibly Sourced Gas
ROFL	Right of First Look
R/P	Reserves to Production Ratio
RTC	Round-the-Clock
SFDR	Sustainable Finance Disclosure Regulation
SRP	Share Repurchase Program
SJV	San Joaquin Valley
TBA	To Be Announced
Tcf	Trillion Cubic Feet
WI	Working Interest

Assumptions & Relevant Footnotes:

A DIFFERENT KIND OF ENERGY COMPANY

Slide 3:

- (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. Free cash flow is equal to net cash provided (used) by operating activities less capital investments.
- (2) Dividends are subject to Board approval. Future dividends are expected to be paid quarterly at $0.31 per share of common stock.
- (3) Source: www.epa.gov/uic/current-class-vi-projects-under-review-epa
- (4) Internal estimates. See slide 13 and 14 of this presentation for additional data on natural gas incremental inventory. The SEC prohibits oil and gas companies, in their filings with the SEC, from disclosing estimates of oil or gas resources other than "reserves," as that term is defined by the SEC. This presentation includes estimates of quantities of oil and gas using certain terms, such as "incremental inventory" or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC's definitions of proved, probable and possible reserves, and which the SEC's guidelines strictly prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being recovered. Readers are urged to consider closely the reserves and other disclosures in our periodic filings with the SEC.

Slide 5:

- (1) 3Q23E guidance assumed a 3Q23 Brent price of $75.28 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $2.73 per mcf. Generally, CRC's share of production under production-sharing contracts (PSCs) decreases when commodity prices rise and increases when prices decline.
- (2) CMB Expenses includes leasing costs for sequestration easements, advocacy costs, and other startup related costs.
- (3) 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. Free cash flow is equal to net cash provided (used) by operating activities less capital investments.
- (4) Impact to cash flow after hedges and before changes in working capital.

Slide 6:

- (1) Dividends are subject to Board approval.
- (2) CRC peers include CHRD, DVN, BRY, PXD, EOG, CHK, MUR, APA, FANG, CRC, SM, MRO, EQT, HES, MTDR. Data as of October 27, 2023.

Slide 8:

- (1) Internal estimates.
- (2) Assumes a 12-year project life. See slide 24 and 25 of this deck for the details on the CTV project economic type curve details and project IRRs.
- (3) EPA Class VI draft permit for CTV I expected by YE23 but is subject to EPA approvals and public review. FID subject to permit approvals.
- (4) Earnings before interest, taxes, depreciation and amortization (EBITDA) is a non-GAAP measure. EBITDA estimates include 45Q tax credits which may change based on further guidance from IRS and other factors.

Slide 9:

- (1) CRC's CDMAs frame the anticipated contractual terms between parties and provide a path to reaching final definitive agreements.
- (2) Earnings before interest, taxes, depreciation and amortization (EBITDA) is a non-GAAP measure. EBITDA estimates include 45Q tax credits which may change based on further guidance from IRS and other factors.
- (3) See slides 24 and 25 of this deck for the details on the CTV project economic type curve.

Slide 11:

- Source: Internal estimates. Numbers may not add up due to rounding. SJ Basin implies San Joaquin basin.
- (1) Our CDMAs frame the anticipated contractual terms between parties and provide a path to reaching final definitive agreements.
- (2) Source: CARB 2020.
- (3) Injection rates are average rates based on max permit volumes over life of project using a 40-year basis. Actual volumes and the injection period will vary over time.
- (4) Includes CRC's decarbonization CCS project at Elk Hills gas plant planned to sequester 100KMPTA of CO_2 which is not under CDMA.
- (5) Internal estimates as of October 2023. Represents remaining capacity after taking into account pore space attributable to signed CDMAs and CRC's projects.

Assumptions & Relevant Footnotes (Cont.):

A DIFFERENT KIND OF ENERGY COMPANY

Slide 14:

- (1) Internal estimates. The SEC prohibits oil and gas companies, in their filings with the SEC, from disclosing estimates of oil or gas resources other than “reserves,” as that term is defined by the SEC. This presentation includes estimates of quantities of oil and gas using certain terms, such as “incremental inventory” or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC’s definitions of proved, probable and possible reserves, and which the SEC’s guidelines strictly prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being recovered. Readers are urged to consider closely the reserves and other disclosures in our periodic filings with the SEC.
- (2) CRC is pursuing a RSG certification for its natural gas assets. This certification depends on many factors which may or may not be achievable.
- (3) Source: ICE forward market price as of October 18, 2023.
- (4) Subject to availability of drilling permits and additional surface infrastructure which may be needed.

Slide 17:

- (1) 2023E guidance assumes a 2023 Brent price of $84.16 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $2.77 per mcf. 4Q23E guidance assumes a 4Q23 Brent price of $90.46 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.00 per mcf. Generally, CRC’s share of production under PSCs decreases when commodity prices rise and increases when prices decline.
- (2) CMB Expenses includes advocacy, and other startup related costs.
- (3) A reconciliation of historical non-GAAP financial measures to the nearest GAAP equivalent and other additional information can be found on the Investor Relations page at www.crc.com. A GAAP reconciliation of forward-looking non-GAAP financial measures can be found in Attachment 3 to the Company's earnings release dated November 1, 2023, also available at www.crc.com.
- (4) Adjusted E&P Capital and Adjusted CMB Capital are Non-GAAP measures. These measures reflect the reclassification of ~$4 million from E&P, Corporate & Other Capital to Adjusted CMB Capital related to investment in facilities to advance carbon sequestration activities.

Slide 24:

The information on slide 24 is an example of project economics for the strategic partnership with Brookfield, which are shared 51% to CRC and 49% to Brookfield. The terms and availability of third-party sources of financing, if needed, could also affect returns and outcomes. The following assumptions were used:

- Assumes that projects are completed and online with no material delays or impediments to the issuance of necessary permits, government approvals, or third party third-party arrangements.
- Assumes development at the mid-point of the CTV JV economic “Type Curve”.
- Assumes 1MMT injected per year for 40-year project life unless specified otherwise.
- Assumes Brookfield fully participates in CCS projects up to JV target of 5MMTPA of injection and 200MMT of CO_2 storage.
- EBITDA amounts that are shown as a range assume the top and bottom ranges of the EBITDA assumptions and are multiplied by 1MM and 5MM to represent 1MMTPA of projects and 5MMTPA of projects, respectively. The EBITDA range presented has been reduced by ~20% – 50% to reflect uncertainties related to project structure, financing and ownership.
- EBITDA estimates include 45Q tax credits which may change based on further guidance from IRS and other factors and assumes that 45Q wage and apprenticeship requirements are met. Based on incentives available under current regulatory framework.
- 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. which may change based on further guidance from IRS and other factors.
- Assumes that a project is cash flow positive in year 4 with payback period of ~ 4 to 6 years and reflects the midpoint of range estimates. Payback period is defined as total CRC investment / annual cash flow and is specifically for CTV JV project level economics.
- 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 23 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.

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, including supply and demand considerations for our products and services;
- decisions as to production levels and/or pricing by OPEC or U.S. producers in future periods;
- government policy, war and political conditions and events, including the wars in Ukraine and Israel and oil sanctions on Russia, Iran and others;
- regulatory actions and changes that affect the oil and gas industry generally and us in particular, including (1) the availability or timing of, or conditions imposed on, permits and approvals necessary for drilling or development activities or our carbon management business; (2) the management of energy, water, land, greenhouse gases (GHGs) or other emissions, (3) the protection of health, safety and the environment, or (4) the transportation, marketing and sale of our products;
- the impact of inflation on future expenses and changes generally in the prices of goods and services;
- changes in business strategy and our capital plan;
- lower-than-expected production or higher-than-expected production decline rates;
- changes to our estimates of reserves and related future cash flows, including changes arising from our inability to develop such reserves in a timely manner, and any inability to replace such reserves;
- the recoverability of resources and unexpected geologic conditions;
- general economic conditions and trends, including conditions in the worldwide financial, trade and credit markets;
- production-sharing contracts' effects on production and operating costs;
- the lack of available equipment, service or labor price inflation;
- limitations on transportation or storage capacity and the need to shut-in wells;
- any failure of risk management;
- results from operations and competition in the industries in which we operate;
- our ability to realize the anticipated benefits from prior or future efforts to reduce costs;
- environmental risks and liability under federal, regional, state, provincial, tribal, local and international environmental laws and regulations (including remedial actions);
- the creditworthiness and performance of our counterparties, including financial institutions, operating partners, CCS project participants and other parties;
- reorganization or restructuring of our operations;
- our ability to claim and utilize tax credits or other incentives in connection with our CCS projects,
- our ability to realize the benefits contemplated by our energy transition strategies and initiatives, including CCS projects and other renewable energy efforts;
- our ability to successfully identify, develop and finance carbon capture and storage projects and other renewable energy efforts, including those in connection with the Carbon TerraVault JV, and our ability to convert our CDMAs to definitive agreements and enter into other offtake agreements;
- our ability to maximize the value of our carbon management business and operate it on a stand alone basis;
- our ability to successfully develop infrastructure projects and enter into third party contracts on contemplated terms;
- uncertainty around the accounting of emissions and our ability to successfully gather and verify emissions data and other environmental impacts;
- changes to our dividend policy and share repurchase program, and our ability to declare future dividends or repurchase shares under our debt agreements;
- limitations on our financial flexibility due to existing and future debt;
- insufficient cash flow to fund our capital plan and other planned investments and return capital to shareholders;
- changes in interest rates;
- our access to and the terms of credit in commercial banking and capital markets, including our ability to refinance our debt or obtain separate financing for our carbon management business;
- changes in state, federal or international tax rates, including our ability to utilize our net operating loss carryforwards to reduce our income tax obligations;
- effects of hedging transactions;
- the effect of our stock price on costs associated with incentive compensation;
- inability to enter into desirable transactions, including joint ventures, divestitures of oil and natural gas properties and real estate, and acquisitions, and our ability to achieve any expected synergies;
- disruptions due to earthquakes, forest fires, floods, extreme weather events or other natural occurrences, accidents, mechanical failures, power outages, transportation or storage constraints, labor difficulties, cybersecurity breaches or attacks or other catastrophic events;
- pandemics, epidemics, outbreaks, or other public health events, such as the COVID-19; and
- other factors discussed in Part I, Item 1A – Risk Factors.

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

Joanna Park (Investor Relations)

818-661-3731

Joanna.Park@crc.com

Richard Venn (Media)

818-661-6014

Richard.Venn@crc.com