CALIFORNIA RESOURCES CORPORATION

A DIFFERENT KIND OF ENERGY COMPANY

August 2025

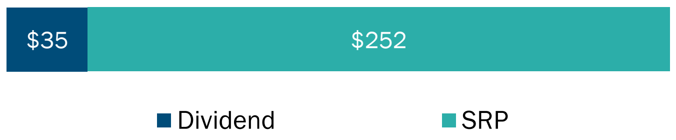
Corporate Presentation

2Q25 Key Takeaways

1. RECORD QUARTERLY CAPITAL RETURNS TO SHAREHOLDERS[1]

- Repurchased **$228MM** of shares in a private deal at $46/sh and **$24MM in the open market** at avg. ~$43.41/sh
- **$205MM remaining** under the authorized share repurchase program
- **Share repurchase program extended** through June 30, 2026

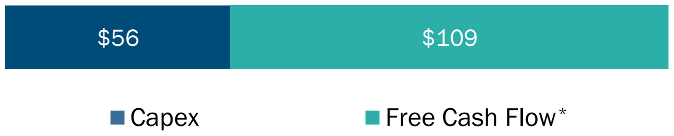
$287MM
2Q25 TOTAL SHAREHOLDER RETURN[1]



2. ROBUST OPERATIONAL AND FINANCIAL PERFORMANCE

- **Delivered strong reservoir performance** with 1% gross and 3% net production QoQ declines; **added second rig in Kern County**
- **Implemented $235MM Aera merger targeted synergies,** 3 months ahead of schedule
- Generated **$324MM of Adj. EBITDAX*,** beating guidance

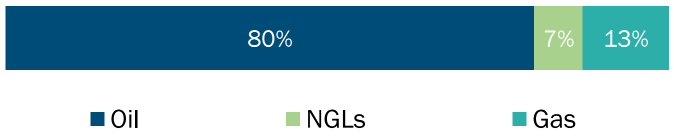
$165MM
2Q25 OPERATING CASH FLOW



3. OPERATIONAL MOMENTUM CONTINUES IN 2025

- **Reduced** 2025E **D&C and workover capital by ~3%; raised the midpoints** of 2025E **net production by ~1%** and **adj. EBITDAX* by ~7%**[2]
- **CTV JV received authorization to construct from the U.S. EPA**
- **CTV remains on track to complete construction of its first CCS project at Elk Hills at or around YE25;** first CO_2 injection in early 2026 pending final regulatory approvals

137MBOE/D
2Q25 NET PRODUCTION



See slide 30 for “Assumptions, Estimates and Endnotes”.

Strong 2Q25
Execution, Execution, Execution

Generating Record Shareholder Returns

Returned

$287MM — Dividends and Buybacks in 2Q25[1]

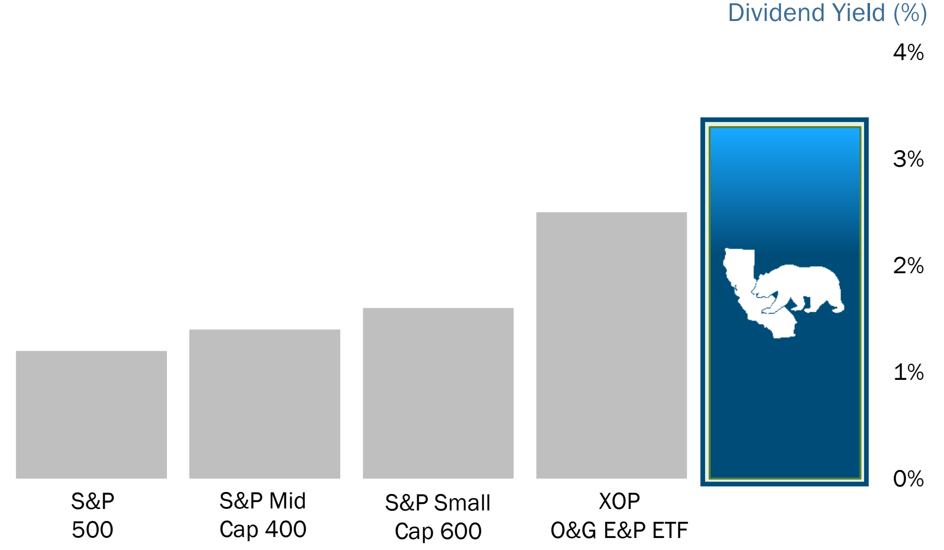
~263% — Of Free Cash Flow* in 2Q25

~86% since May 2021

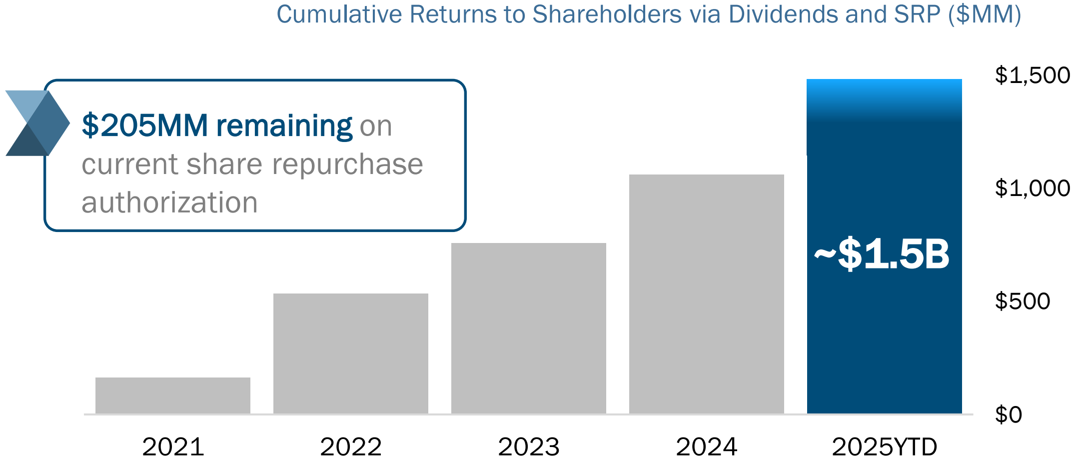
$422MM — Dividends and Buybacks in 1H25[1]

$1,482MM since May 2021[1]

Competitive Dividend Yield vs. Market[2]



Significant Return of Capital to Shareholders[1]

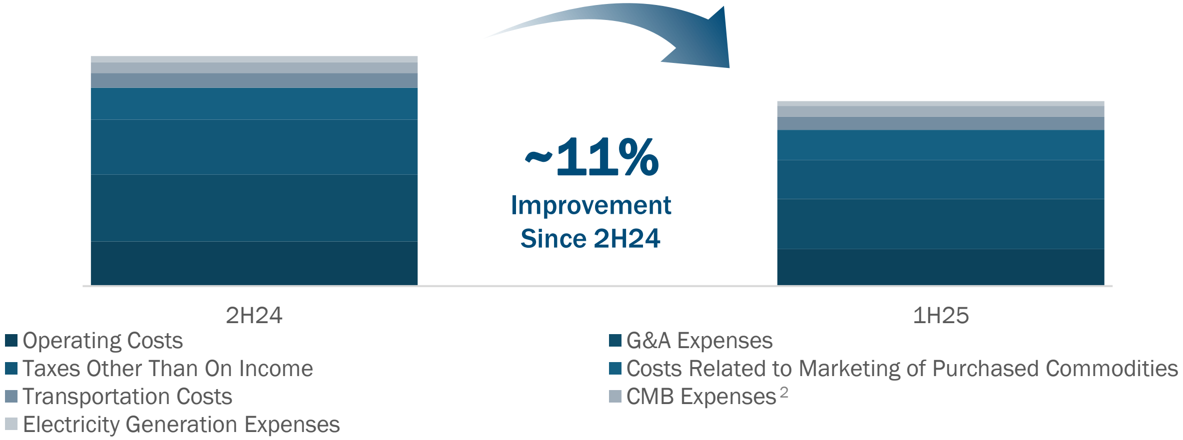


See slide 30 for "Assumptions, Estimates and Endnotes".

Demonstrating Operational Excellence & Better Capital Efficiency

Lower Costs

($MM)



Lower Capital

D&C and Workover Capital ($MM)

- *Key drivers of lower 1H25 costs vs. 2H24: reductions in G&A, decrease in production and GHG taxes and lower non-energy operating costs[1]*
- *Reservoir outperformance driven by continuous focus on operational efficiencies and value capture at Belridge and Elk Hills*

$240MM

1H25 Free Cash Flow*

"We are trying to recover every cup from every underground barrel ... All of them ... 672 cups ..."

- CRC Elk Hills Operator

See slide 30 for "Assumptions, Estimates and Endnotes".

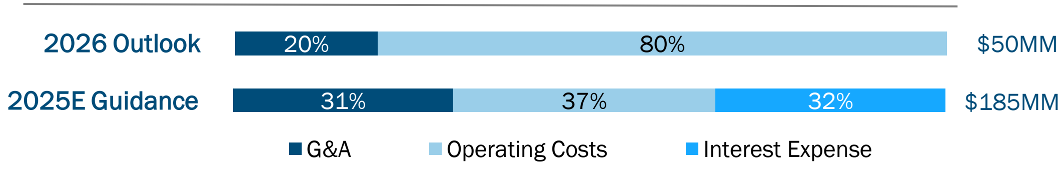
Delivered on Aera Merger Synergies Goal

One Year Post Close Implemented

$235MM

Aera Merger Synergies

Synergies Impact



See slide 30 for “Assumptions, Estimates and Endnotes”.

Increasing Operational Intensity in 2H25

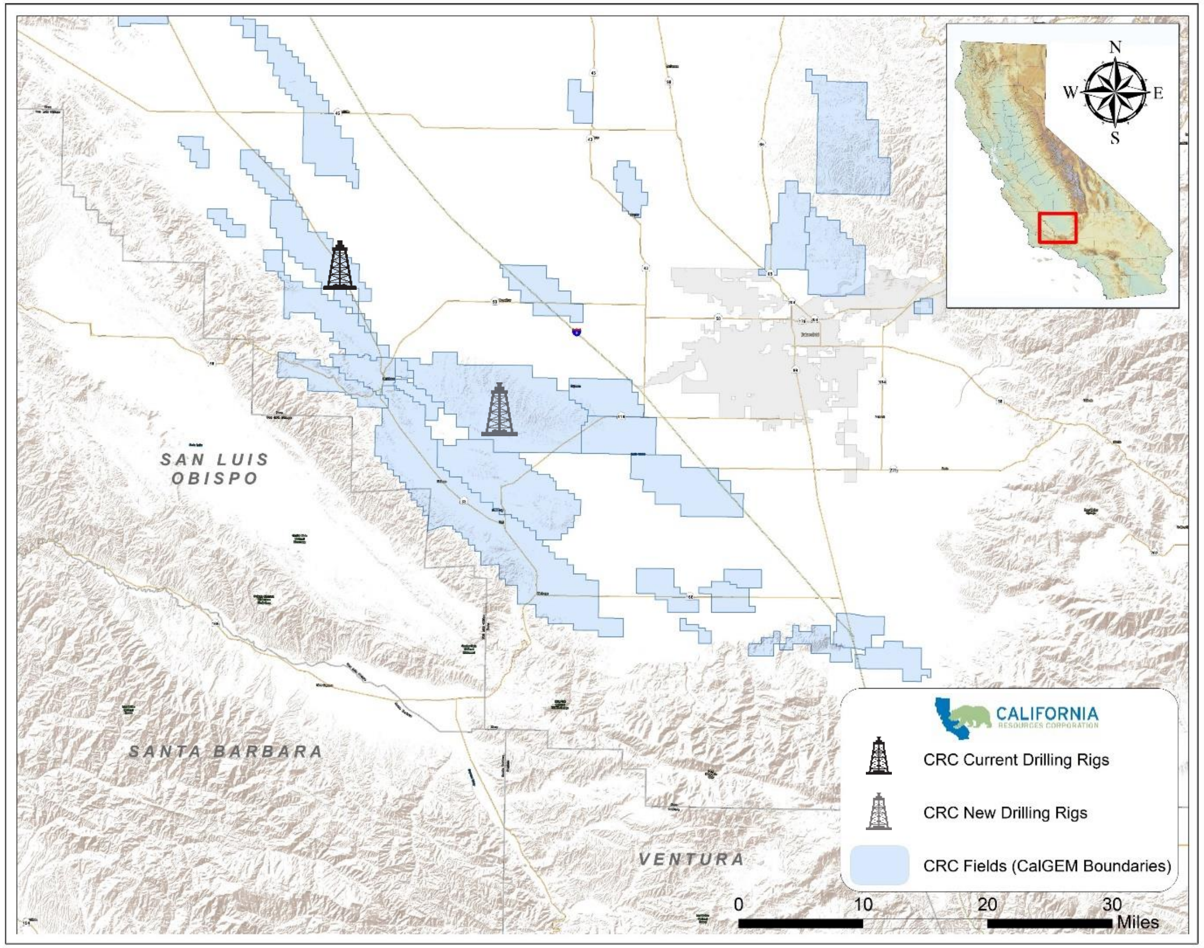
Adding Activity in 2H25

- Added second rig in Kern County in late June 2025 for a total 16 well 2025 drilling program
- Investments focused on high-value, high-margin sidetracks and workovers
- Targeting development program IRRs of >30% at $63 Brent / $3.50 NYMEX

CRC 2025E O&G Project Economics[1]	Brent >25% IRR ($/Bbl)	WTI >25% IRR ($/Bbl)
Workovers	~$34	~$31
New Drills *(Average of sidetracks)*	~$58	~$55

Improving 2025E Production Expectations, Capital Efficiency Driving Momentum into 2026[2]

- Raising 2025E net production guidance by 1MBoe/d at midpoint
- Targeting 5% - 7% entry-to-exit gross production decline for 2025
- 2025E D&C and workover capital reduced by $5MM



$160 – $175MM

Reduced
2025E D&C and Workover Capital[2]

134 – 138MBoe/d

Increased Midpoint
2025E Net Production[2]

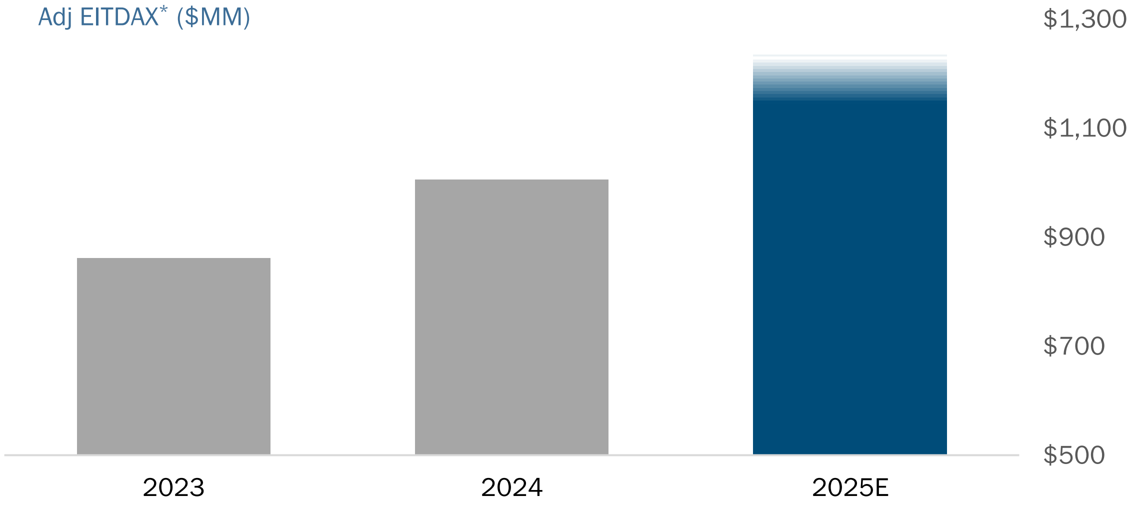
See slide 30 for “Assumptions, Estimates and Endnotes”.

2Q25 Results

Commodity	2Q25E[1]	2Q25A
Brent ($/Bbl)	$63.00	**$66.76**
Brent realized price with hedge ($/Bbl)	N/A	**$66.73**
Oil realization without derivative settlements (% of Brent)	96% – 100%	**97%**
Operational and Financial		
Net Production (MBoe/d)	133 – 137	**137**
Net Oil Production (%)	79%	**80%**
Operating Costs ($MM)	$295 – $315	**$295**
G&A Expenses ($MM)	$76 – $80	**$79**
Adj. G&A* Expenses ($MM)	$69 – $74	**$72**
Taxes Other Than on Income ($MM)	$60 – $65	**$47**
Other Operating Expenses Net of Other Revenue*, [2] ($MM)	$5 – $20	**$60**
Total Capital ($MM)	$81 – $92	**$56**
Adjusted EBITDAX* ($MM)	$275 – $290	**$324**
Operating Cash Flow Before Net Changes in Operating Assets and Liabilities* ($MM)		**$221**
Other Items		
Margin from Purchased Commodities*, [3] ($MM)	$20 – $25	**$15**
Electricity Margin*, [4] ($MM)	$40 – $45	**$53**
Transportation Costs ($MM)	$22 – $26	**$20**
Total Return of Cash to Shareholders[5] ($MM)		
Share Repurchases ($MM)		**$252**
Dividends Paid ($MM)		**$35**
Total ($MM)		**$287**

See slide 30 for "Assumptions, Estimates and Endnotes".

Higher Adj. EBITDAX* Expectations



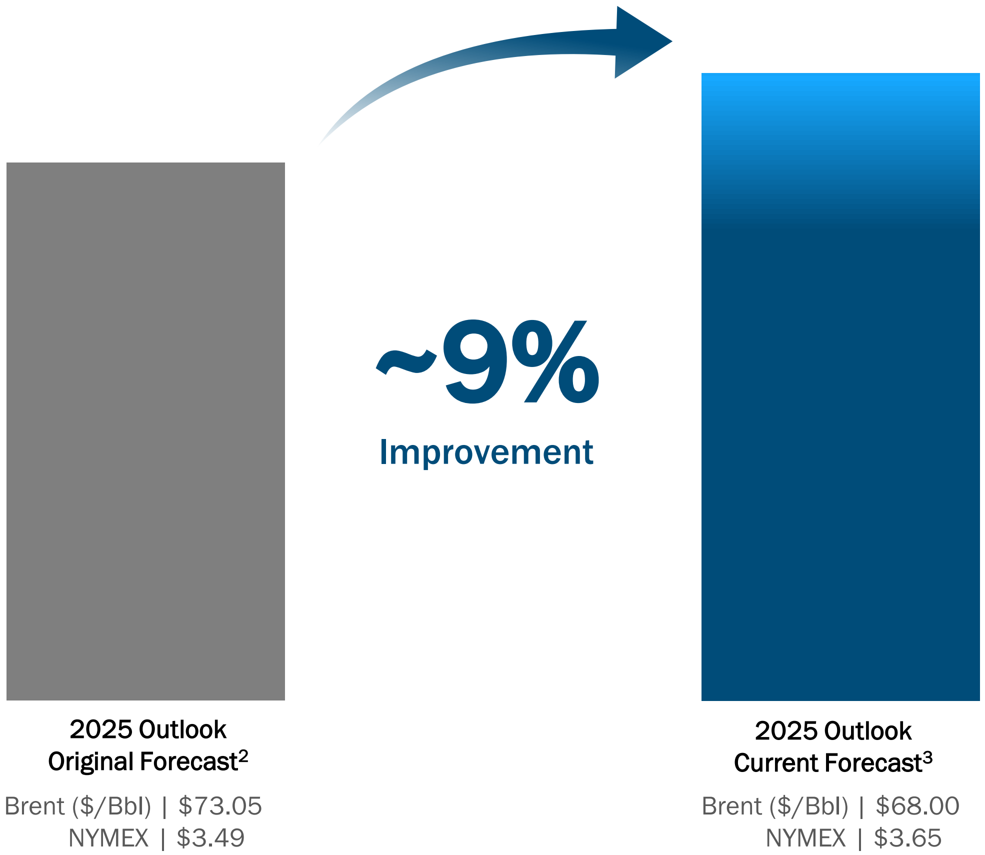
2Q25 Commentary: Stronger than Expected Quarter Across the Board

- Quarterly Brent pricing and production exceeded expectations, latter driven by asset and process optimization
- Synergies capture and disciplined cost control led to lower operating expenses
- Taxes other than on income came in below forecast due to lower production taxes and GHG prices
- Quarterly activity deferral to 2H25 through asset optimization resulted in lower-than-expected capital investments
- Stronger electricity margin* was related to capacity sales. Better energy operating costs were due to lower gas prices related to elevated in-state natural gas storage levels
- Cash flow was negatively impacted by a one-time $25MM payment for a legal matter

Operational Momentum

Stronger 2025 Free Cash Flow* Outlook Despite Lower Oil Price Forecast

Free Cash Flow Before Net Changes in Operating Assets and Liabilities[1] ($MM)



2025 Enhanced Outlook Driven By

- Strong Reservoir Performance
- Aera Merger Synergies
- Higher Electricity Margin
- Lower Production & GHG Taxes
- Lower Cash Taxes & Interest

See slide 30 for "Assumptions, Estimates and Endnotes".

2025E Guidance

Driving Operational Strength and Efficiency in 2025

EXPECTING EVEN LOWER COSTS[1, 2] IN 2025 | **~2%** | DRIVEN PRIMARILY BY SYNERGIES, OPERATIONAL EFFICIENCIES AND ENERGY COST SAVINGS

REDUCED 2025E D&C AND WORKOVER CAPITAL GUIDANCE[2] | **~3%** | DRIVEN PRIMARILY BY PROJECT OPTIMIZATION

RAISED PRODUCTION MIDPOINT OF 2025E GUIDANCE[2] | **~1%** | DRIVEN PRIMARILY BY BETTER RESERVOIR PERFORMANCE AND IMPROVED OPERATIONS

RAISED ADJ. EBITDAX* MIDPOINT OF 2025E GUIDANCE[2] | **~7%** | DRIVEN PRIMARILY BY HIGHER COMMODITY PRICE, STRONGER PRODUCTION EXPECTATIONS AND LOWER COSTS

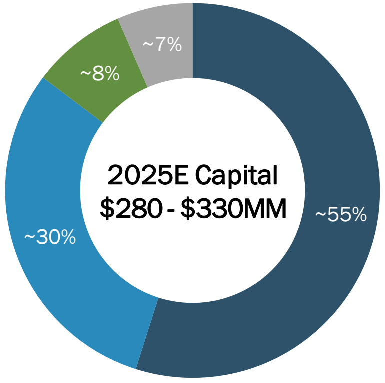
See slide 30 for “Assumptions, Estimates and Endnotes”.

2025E Guidance *(as of August 5, 2025)*

CRC Guidance	3Q25E Consolidated	Oil and Natural Gas	Carbon Management	2025E Consolidated	Oil and Natural Gas	Carbon Management
Net Production (MBoe/d) ~79% Oil	**135 – 139**			**134 – 138**		
Margin from Purchased Commodities*,[1] ($MM)	$17 – $25			$65 – $80		
Electricity Margin*,[2] ($MM)	$75 – $100			$175 - $190		
Operating Costs ($MM)	$300 – $330	$300 – $330		$1,220 – $1,280	$1,220 – $1,280	
G&A ($MM)	$74 – $88	$10 – $14	$2 – $4	$310 – $335	$40 – $55	$10 – $15
Adjusted G&A ($MM)*	*$70 – $80*	*$10 – $14*	*$2 – $4*	*$290 – $310*	*$40 – $55*	*$10 – $15*
Depreciation, Depletion and Amortization ($MM)	$131 – $135	$112 – $118		$515 – $530	$447 – $462	
Other Operating Expenses Net of Other Revenue*,[3] ($MM)	$0 – $20		$7 – $13	$80 – $135		$45 – $60
Transportation Expense ($MM)	$20 – $26	$9 – $13		$82 – $94	$39 – $43	
Taxes Other Than on Income ($MM)	$64 – $74	$52 – $57		$235 – $260	$190 – $220	
Interest and Debt Expense ($MM)	$25 – $29			$100 – $110		
Capital ($MM)	**$84 – $108**	**$71 – $89**	**$8 – $10**	**$280 – $330**	**$245 – $275**	**$20 – $30**
Adj. EBITDAX* ($MM)	**$310 – $340**	**$280 – $305**	**($15) – $(11)**	**$1,195 – $1,275**	**$1,210 – $1,340**	**($68) – ($64)**

Other Assumptions	3Q25E	2025E
Brent ($/Bbl)	$66.00	$68.00
NYMEX ($/mcf)	$3.40	$3.65
Oil – % of Brent	94% – 100%	95% – 99%
NGL – % of Brent	54% – 60%	60% – 68%
Natural Gas – % of NYMEX	94% – 104%	90% – 110%
Deferred Income Taxes	95% – 105%	35% – 45%
Effective Tax Rate	29%	29%

Preliminary 4Q25 Net Production Range of 131 – 135 MBoe/d



See slide 30 for “Assumptions, Estimates and Endnotes”.

Why California Resources Corporation?

A DIFFERENT KIND OF ENERGY COMPANY

Higher **Cashflow**

Less **Carbon**

Better **California**

- LEADING CARBON MANAGEMENT BUSINESS
- PREMIER BALANCE SHEET WITH STRONG FREE CASH FLOW GENERATION
- SUSTAINABLE SHAREHOLDER RETURNS
- DISCIPLINED CAPITAL ALLOCATION

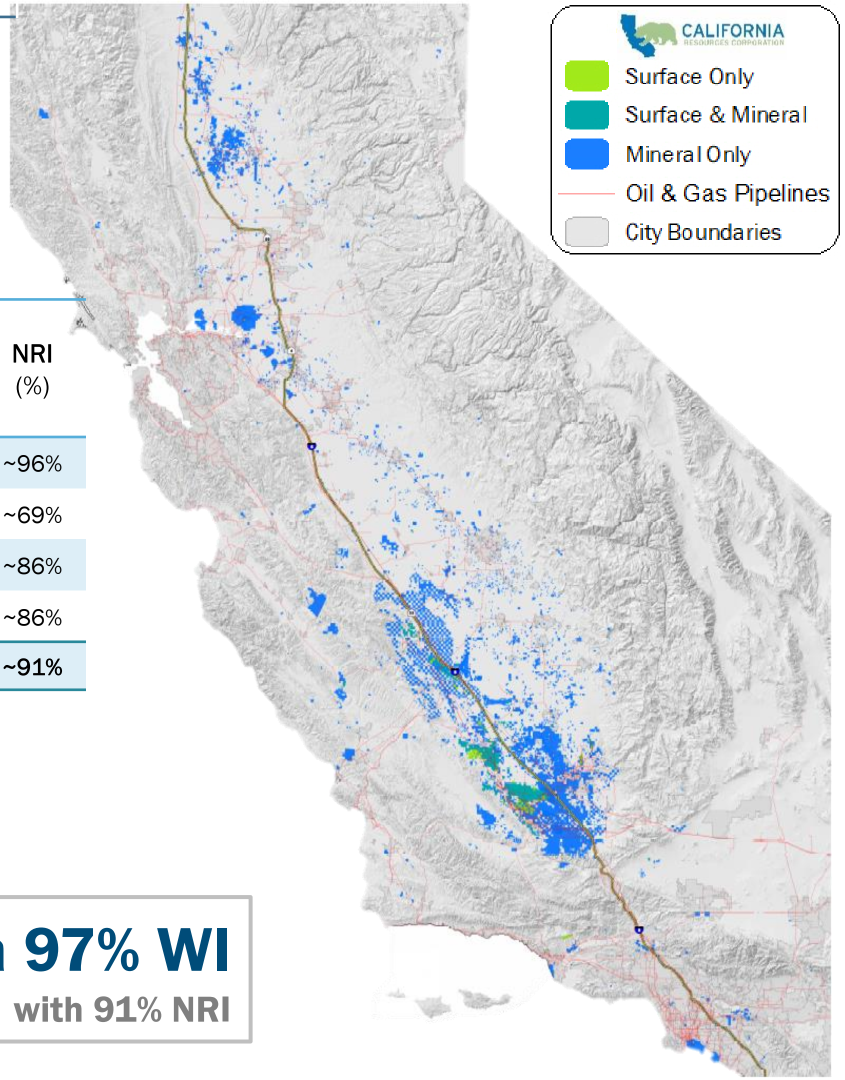
Appendix

Unique California Based Pure–Play Footprint

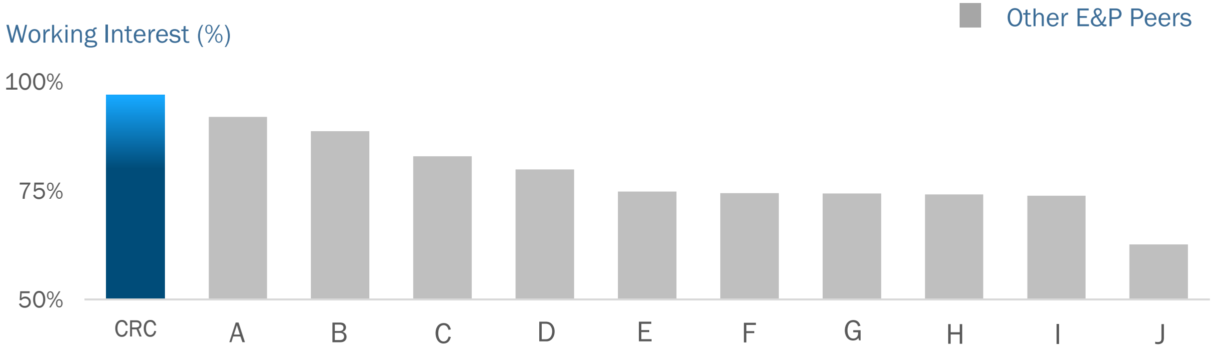
Superior Portfolio Characteristics

- **Strategic Acreage Footprint:** Advantaged position in key California basins provides capital deployment flexibility
- **High-Quality, Low-Decline Assets:** Conventional reservoirs with low capital intensity and stable production
- **Robust Development Inventory:** Diverse recovery methods (primary, secondary, tertiary) support long-term production
- **Ready for Growth:** Ability to accretively grow volumes as permits become available
- **Superior Economics:** High net revenue interest (NRI) drives stronger margins and value capture

Durable 1P Asset Inventory[1]	PDP (%)	Total Proved (MMBOE)	Oil (%)	Est. Annual PDP Decline (%)	4Q24 Net Production (MBOE/D)	R/P[2] (Years)	Recovery Factor (%)	Surface Acreage ('000)	Mineral Acreage ('000)	NRI (%)
San Joaquin Basin	83%	441	78%	~12%	112	11	~31%	190	1,277	~96%
Los Angeles Basin	95%	78	99%	~8%	17	13	~36%	<1	35	~69%
Sacramento Basin	66%	3	0%	~9%	2	4	~59%	<1	421	~86%
Other Basins	95%	23	95%	~12%	10	6	~27%	3	130	~86%
Total	**85%**	**545**	**81%**	**~11%**	**141**	**11**	**~32%**	**193**	**1,863**	**~91%**



CRC's WI vs Peers[3]



CRC has a 97% WI
with 91% NRI

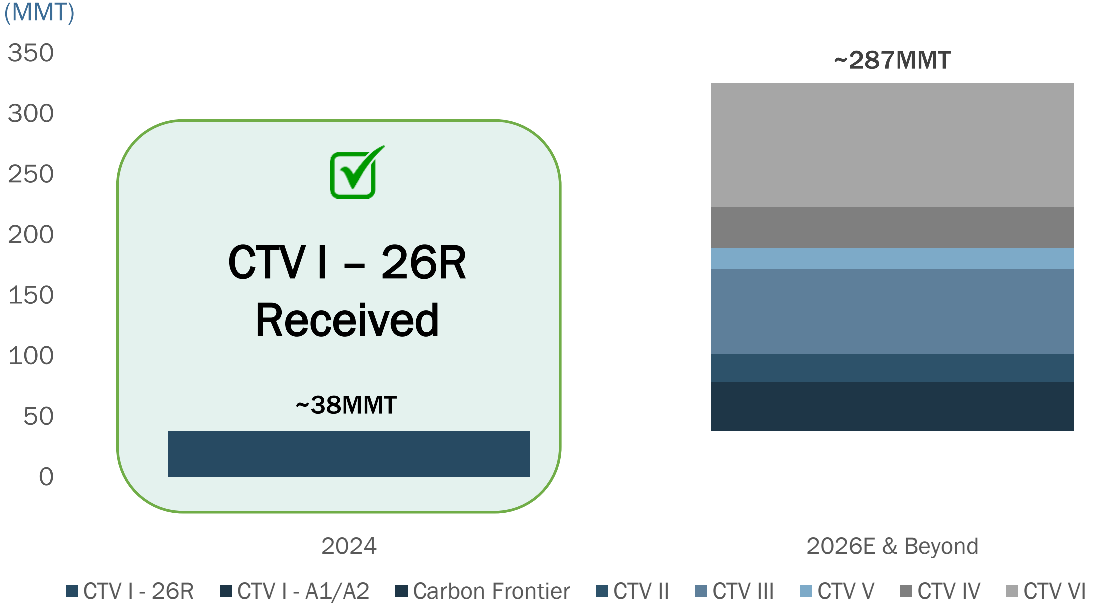
See slide 31 for "Assumptions, Estimates and Endnotes".

Leading California's Decarbonization

EXPANDING OUR CO_2 PERMITTING LEADERSHIP

- Received CA's first EPA Class VI permits for CTV I – 26R
  - Permits became effective February 3, 2025
- 7 EPA Class VI permits in queue for ~287MMT of storage[1]
- Expect to submit additional reservoirs to the EPA for Class VI permitting in 2025

CO_2 Storage Space Submitted to EPA for Class VI Permits[1]



ADVANCING DECARBONIZATION IN CALIFORNIA

- Third party funding through partnership with Brookfield Renewable - Global Energy Transition Fund *(Initial commitment of up to $500MM)*[2]
- Approved California's first CCS project at Elk Hills Cryogenic Gas Plant
  - Ongoing engineering, equipment preparation and procurement for construction underway
- Attracting private and federal clean energy capital to California[3] through carbon management efforts
- Largest amount of potentially available and stackable incentives for CCS development in the country
- Expecting support for CO_2 pipeline transportation from California legislators in 2025
- Identified up to 1BMT[4] of potential CO_2 storage in California

CARBON TERRAVAULT

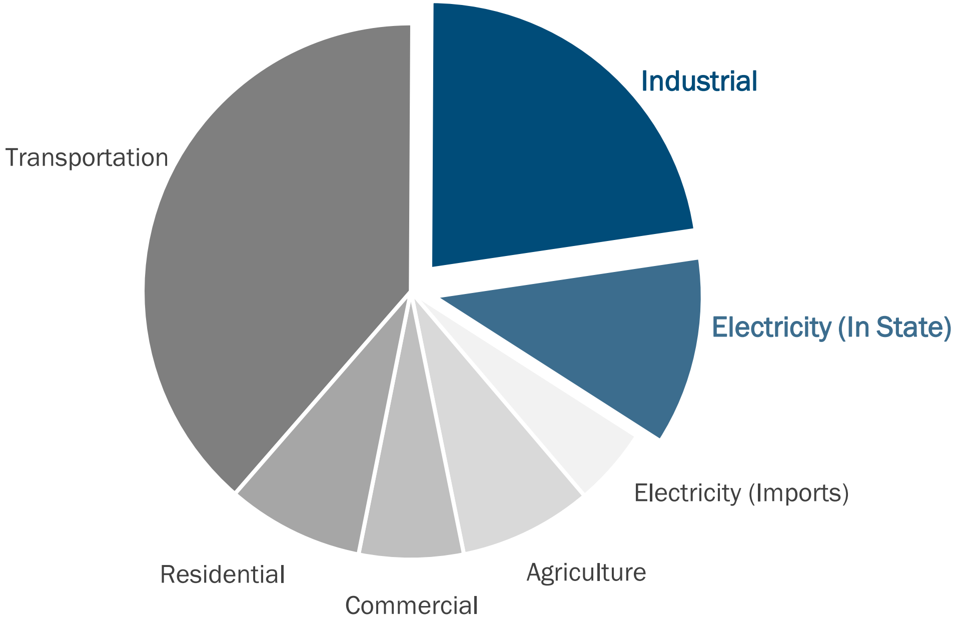
Positioned to Be California's Premier Carbon Management Provider

See slide 31 for "Assumptions, Estimates and Endnotes".

Well Positioned to Decarbonize California's Largest Industries

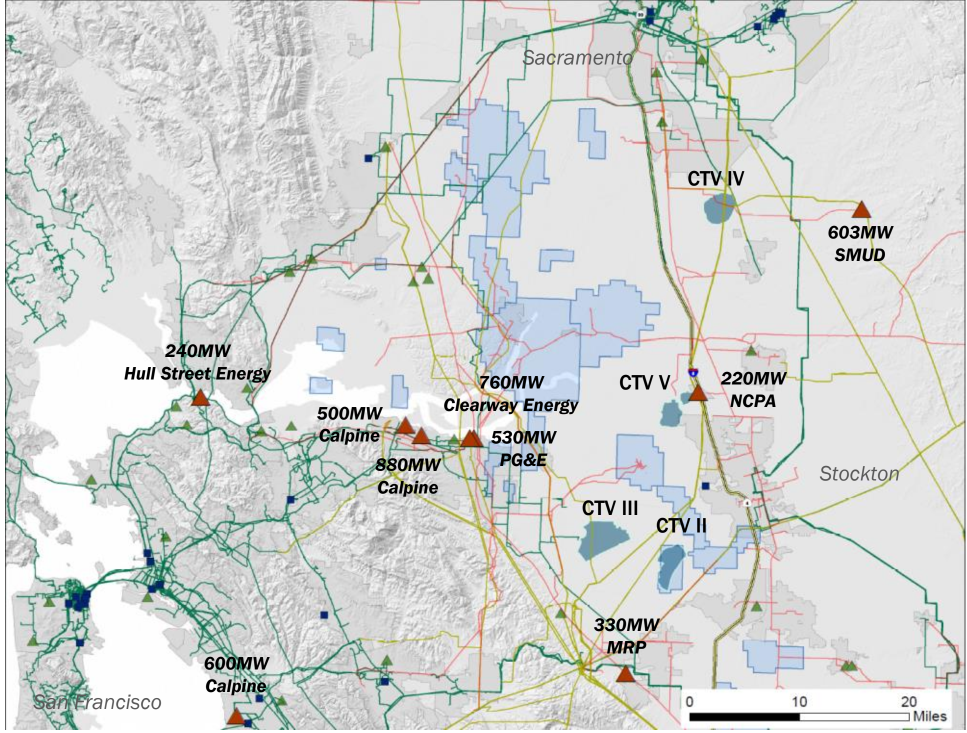
- CTV reservoirs are in proximity to the state's highest emitting industries
- Resource inventory and infrastructure in place to supply energy today
- Ability to provide power services with:
  - Accelerated time-to-market
  - Access to natural gas and interconnection
  - Proximity to fiber network
- Developing carbon free power solutions in San Joaquin Valley

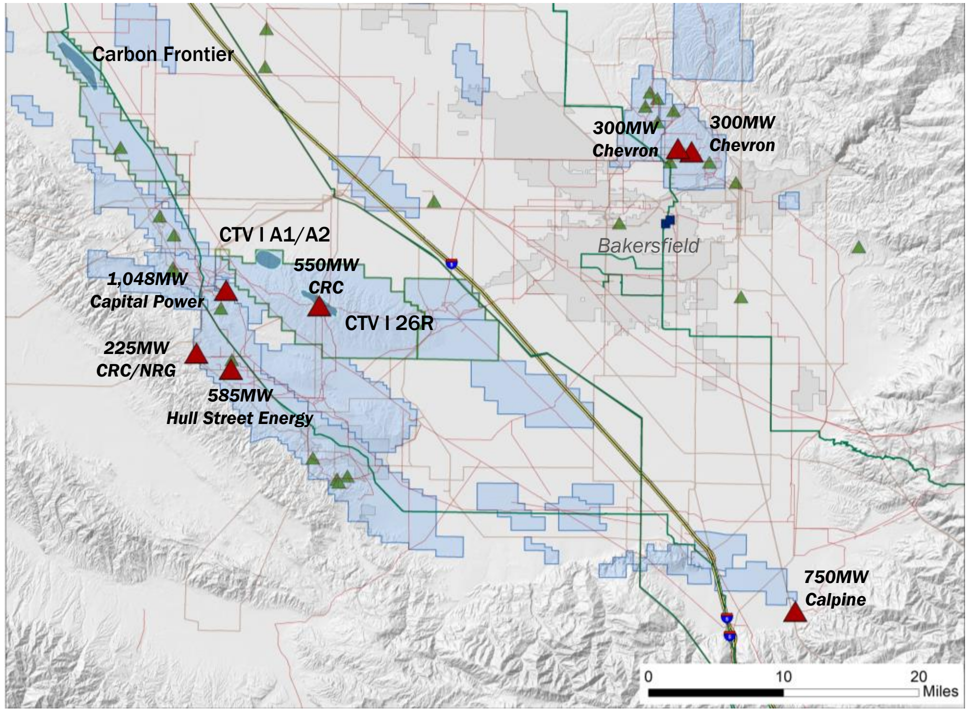
CALIFORNIA GHG EMISSIONS BY SECTOR[1]



CARBON TERRAVAULT[2]

- CTV Storage Projects
- NG Power Plants >=220MW
- NG Power Plants <220MW
- Existing Data Centers
- Fiber Optic Lines
- Power Transmission
- Natural Gas Pipelines
- Oil & Gas / Saline Aquifers





See slide 31 for "Assumptions, Estimates and Endnotes".

California's Premier Carbon Management Provider

- Received Kern County Board of Supervisors' approval of the conditional use permits for the CTV I CCS project
- Received CA's first EPA Class VI permits for CTV I – 26R; Approved California's first CCS project at Elk Hills Cryogenic Gas Plant
- Anticipating the receipt of Class VI draft permits for additional reservoirs in 2025[1]

Vault / Reservoir		Targeted Final EPA Class VI Permit Decision[1]	Est. Annual Injection Rate[1] (MMTPA)			Permit Volumes[1] (MMT)
			EPA Class VI Permit	20 Years	40 Years	
CTV I	26R	Permit Received	~1.5[2]	~1.9	~1.0	~38
	A1-A2	2026E	~0.8	~0.4	~0.2	~8
Carbon Frontier		2026E	~3.3	~1.6	~0.8	~32
CTV VI		2026E	~3.4	~5.1	~2.5	~102
Coles Levee		*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
Central California			**~9.0**	**~9.0**	**~4.5**	**~180**
CTV II		2026E	~1.0	~1.2	~0.6	~23
CTV III		2026E	~2.5	~3.6	~1.8	~71
CTV IV		2026E	~1.4	~1.7	~0.9	~34
CTV V		2026E	~0.7	~0.8	~0.4	~17
Northern California			**~5.6**	**~7.3**	**~3.7**	**~145**
Total - Combined			**~14.6**	**~16.3**	**~8.2**	**~325**

Target Addressable Market by Region[3]

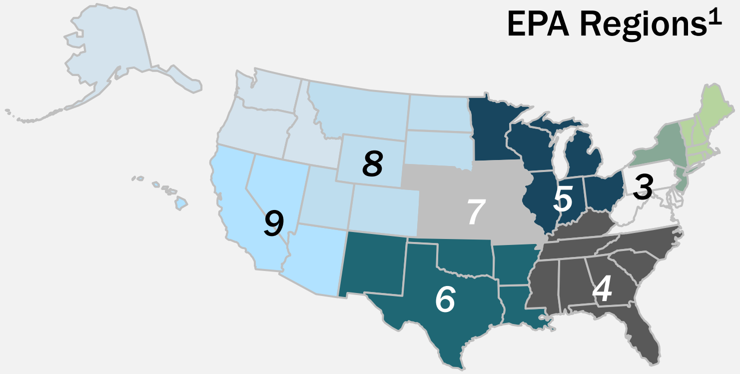
Annual Regional CO_2 Emissions (MMTPA)

CARBON TERRAVAULT

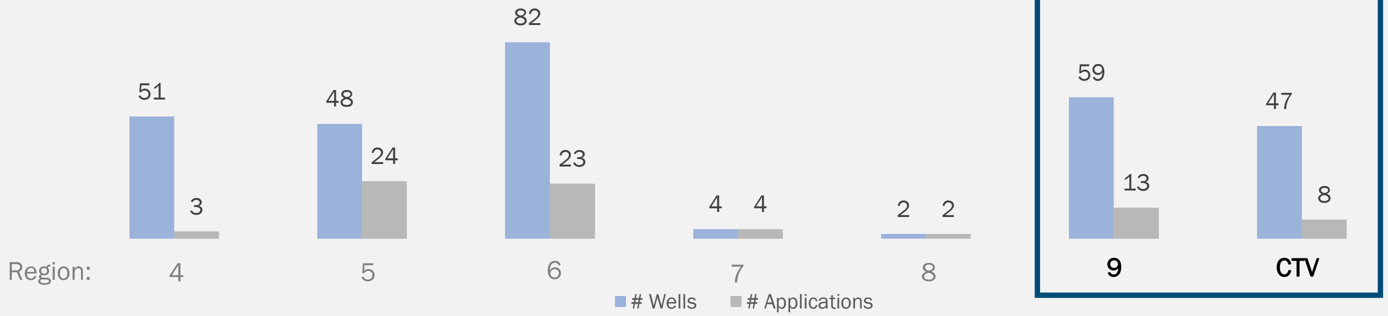
See slide 31 for "Assumptions, Estimates and Endnotes".

Leading EPA Class VI Permitting Pipeline *(As of July 18, 2025)*

EPA Regions[1]

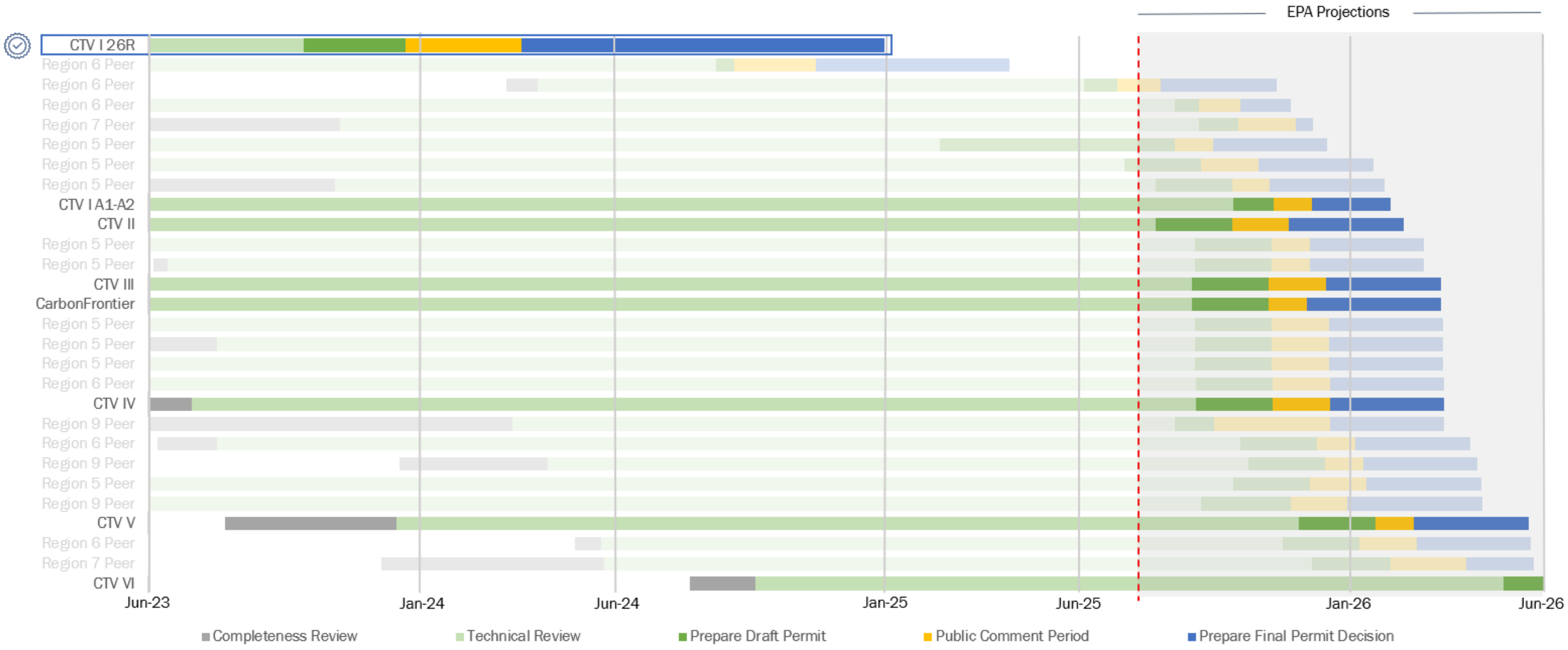


EPA Class VI Projects Under Review[1]



EPA Projected Permit Timeline[1]

Targeting **additional permitted CO_2** space in 2025



See slide 31 for "Assumptions, Estimates and Endnotes".

Multiple Paths to Decarbonize

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 CI of their product and the brownfield takes the decarbonized product to market
- Decarbonization enabled by emissions which are transported by physical pipe

California's Brownfield Emitters

Decreasing Market Share

California Marketplace Demand

Direct pipeline

Emissions injected into CO_2 Storage

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**

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

Rise of New California Greenfield Emitters

Increasing Market Share

California Marketplace Demand

Decline of California's Brownfield Emitters

Decreasing Market Share

Fully Decarbonized product reaches the market

Emissions injected into CO_2 Storage

California receives new green capital injection, new employment and taxes

Gray Emissions are displaced with Greenfield products through substitution

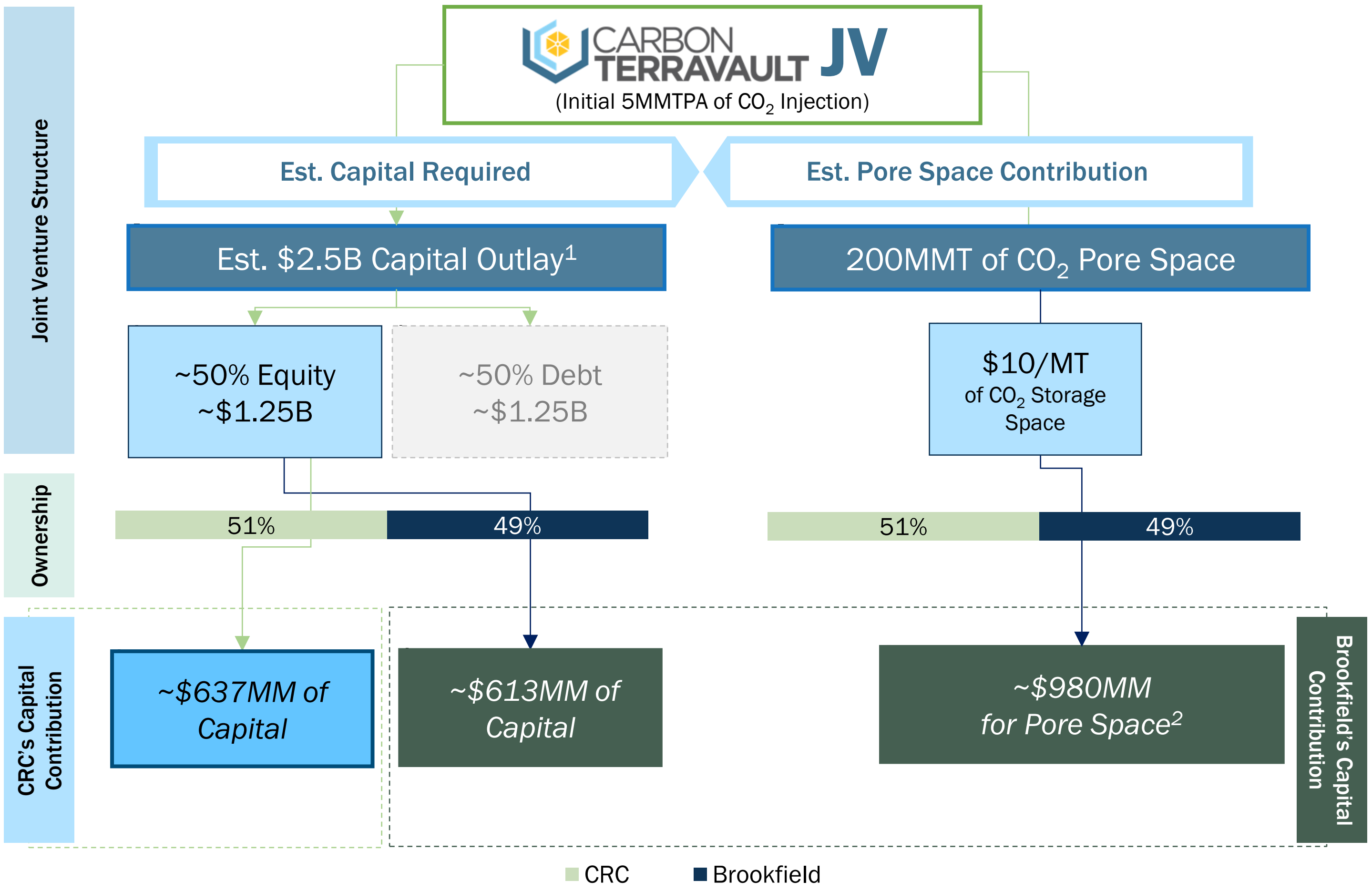
"Virtual Pipeline" of CO_2 created via reduced demand for gray product

Brownfield emitters see decline in revenues, area exits, higher costs and social impacts

Leading California's Decarbonization

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

assumes Brookfield fully participates in the initial 5MMTPA of CTV JV projects



Improves & Increases Flexibility of CRC's Capital Allocation Framework

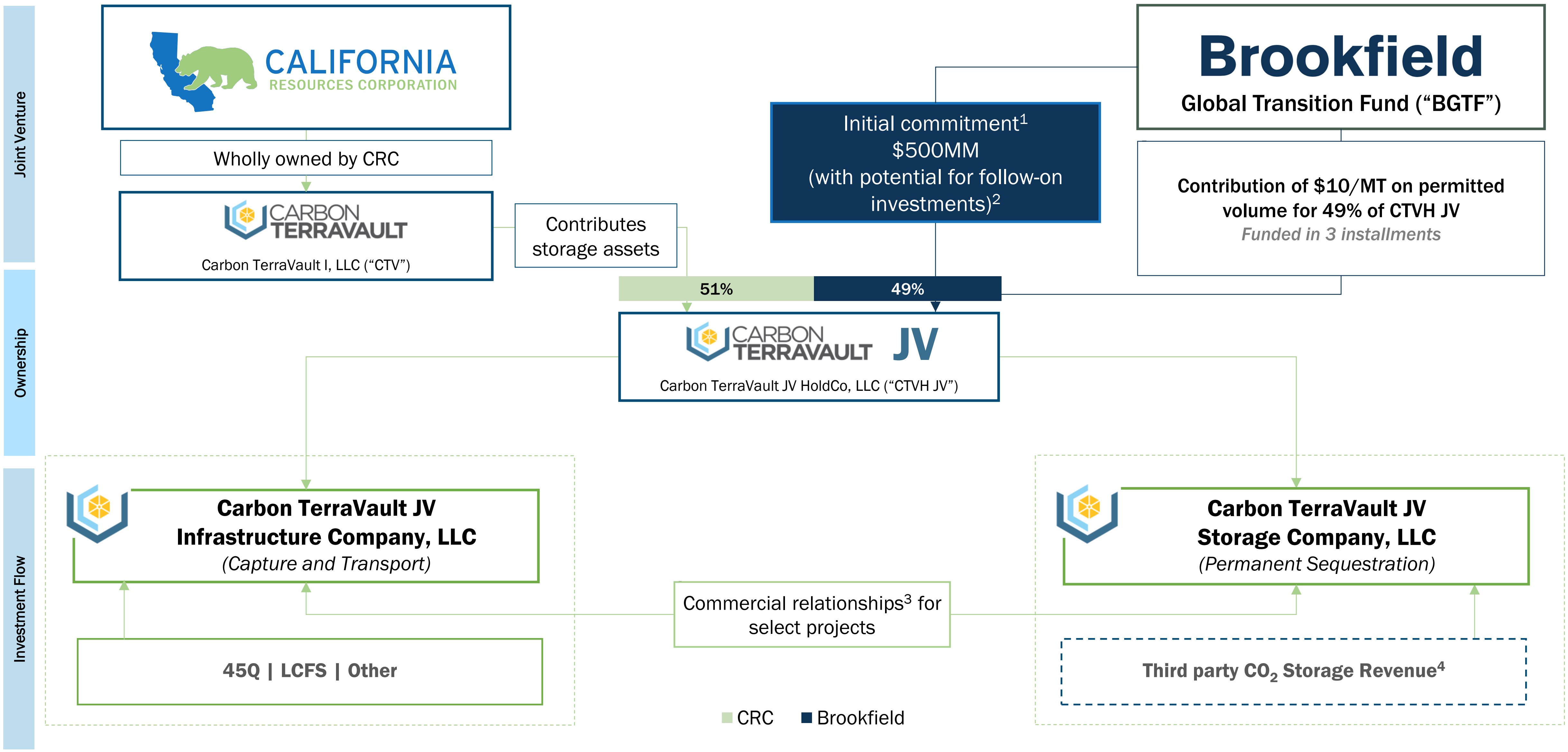
- Capitalizes first 5MMTPA of projects and provides potential funding for CRC's development of 200MMT of CO_2 storage
- CRC's equity commitments for the first 5MMTPA are more than 2x covered by Brookfield's initial commitment for projects jointly approved through the CTV JV
- Allows CRC to increase flexibility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

Projected Excess Capital Available for Early Stage CMB Expenses and Capital[3]

~$980MM	Est. Brookfield Pore Space Contribution
– ~$637MM	Est. CRC's Capital Contribution
~$343MM	Available to fund CRC early stage CMB expenses and capital (represents approximately 5 years of early stage CMB capital spending)

See slide 31 for "Assumptions, Estimates and Endnotes".

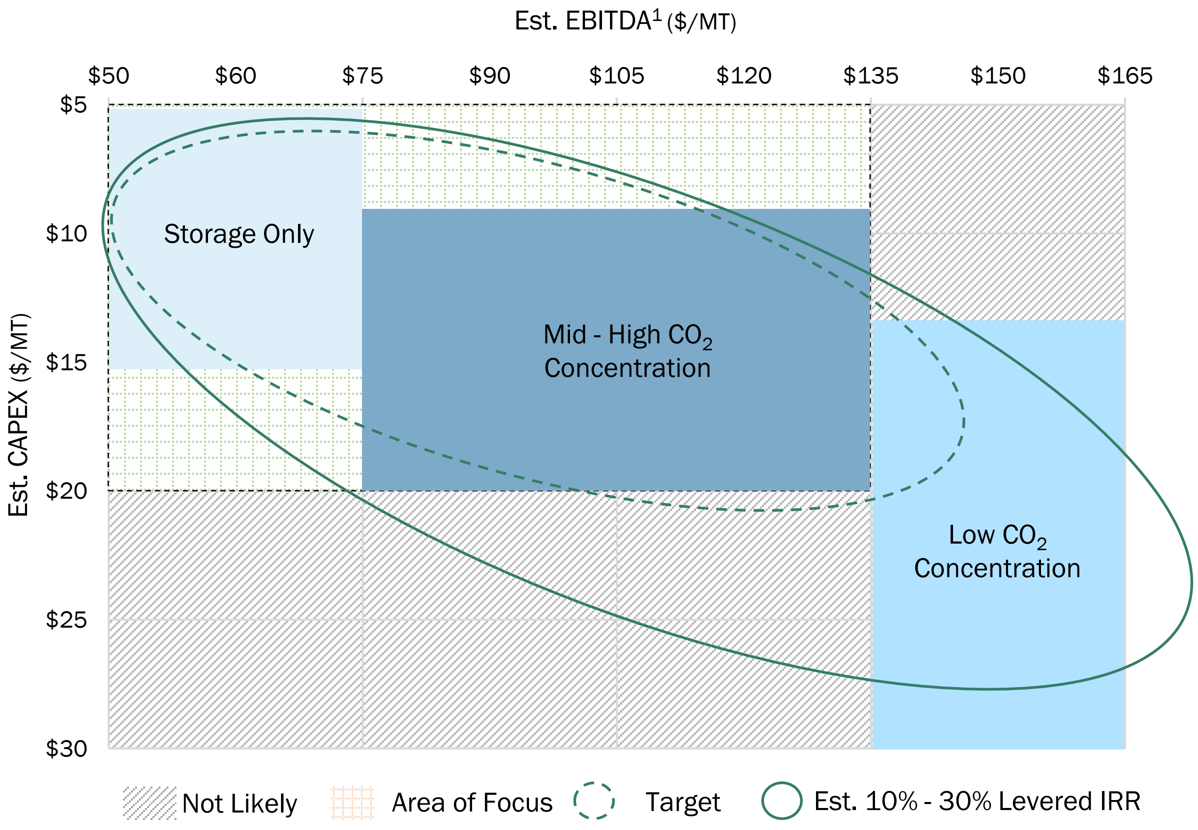
Strategic Partnership and Carbon TerraVault Joint Venture Details



Note: Diagram for illustrative purposes only. See slide 31 for "Assumptions, Estimates and Endnotes".

Strategic Partnership – A Structural Capital Advantage

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)

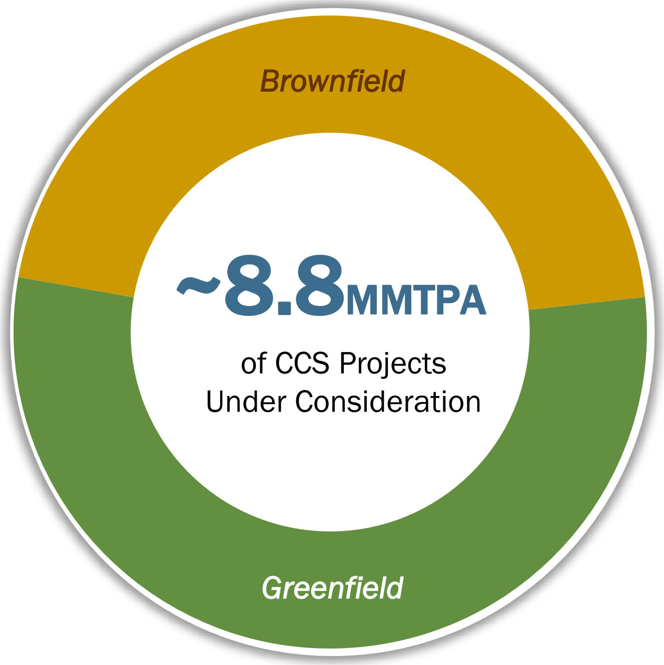
- CTV JV controls the entire value chain (capture to storage) and majority of the incentives
- Capital requirements for capture systems, while still significant, are expected to be on the lower end of the capture cost curve due to higher CO_2 concentration of stream
- Project financing more likely vs. 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. See Slide 31 "Assumptions, Estimates and Endnotes"

Making Tangible Steps Towards Decarbonizing California's Industries

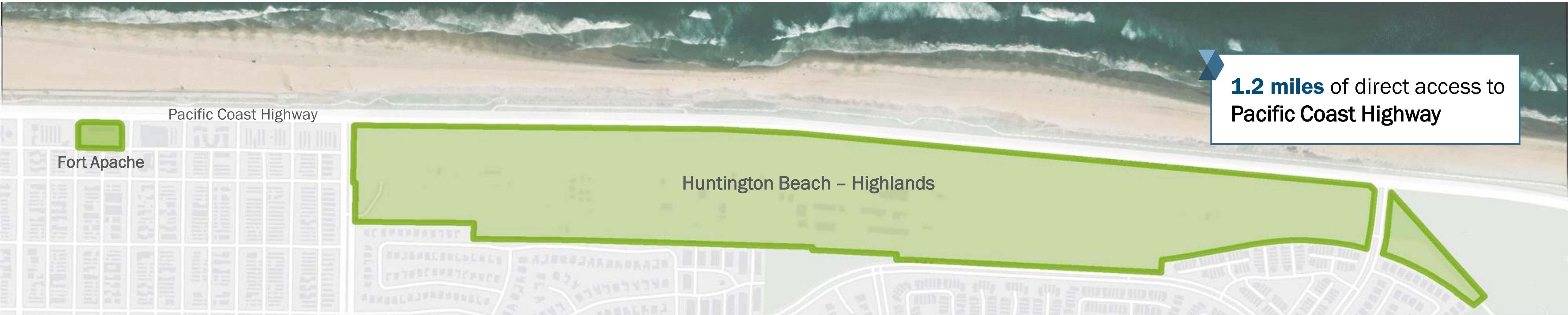


WORKING ALONGSIDE OTHER INNOVATIVE COMPANIES TOWARD A DECARBONIZED CALIFORNIA

Emitter	Project Type	Service	CO_2 Emissions (MMTPA)	Agreement Type[1]
CRC | CalCapture	Post - Combustion	Capture to Storage	~1.4	In House
CRC | Cryogenic Gas Plant	Pre - Combustion	Capture to Storage	~0.1	In House
CRC | Carbon Frontier	Post - Combustion	Capture to Storage	Under Evaluation	In House
National Cement	Carbon-Neutral Cement	Transport to Storage	~1.0	MOU
Hull Street Energy	Post - Combustion	Capture to Storage	~1.5	MOU
Brownfield Emitters			**~4.0**	
Grannus	Clean Ammonia	Storage-Only	~0.4	CDMA
InEnTec	rDME Facility	Storage-Only	~0.1	CDMA
Lone Cypress	Clean Hydrogen	Storage-Only	~0.2	CDMA
Net Power	Clean Power	Transport to Storage	~3.6	MOU
NLC Energy	Renewable Natural Gas	Storage-Only	~0.4	CDMA
Verde Energy	Renewable Gasoline	Storage-Only	~0.1	CDMA
Yosemite Clean Energy	Renewable Green Hydrogen	Storage-Only	<0.1	CDMA
DAC Hub	Direct Air Capture	Storage-Only	TBD	Lead Consortium Member
Greenfield Emitters			**~4.8**	

See slide 31 for "Assumptions, Estimates and Endnotes".

Progressing Huntington Beach Real Estate Asset Development



HUNTINGTON BEACH UPDATE| 92 ACRE PARCEL

- Sold Fort Apache (0.9-acre parcel) for total proceeds of ~$10MM in February 2024 (1810 Pacific Coast Highway, Huntington Beach, CA)
- Anticipated to be a multi year process to maximize land value (20101 Goldenwest Street, Huntington Beach, CA)
- Submitted rezoning application to City of Huntington Beach in March 2025 for a mixed-use, community development
  - Up to 800 homes, up to 350 hotel rooms, retail and dining, and open space parks

TIMELINE

- Proposal will be reviewed by the City staff and community
- City will evaluate project under California Environmental Quality Act (CEQA) to ensure compliance with state environmental regulations
- Huntington Beach Planning Commission will review proposal and make recommendations to the City Council, which will conduct its own evaluation before making a final decision anticipated in mid-2026
- Once approved by the City Council, the project would be presented to the California Coastal Commission for final review and approval

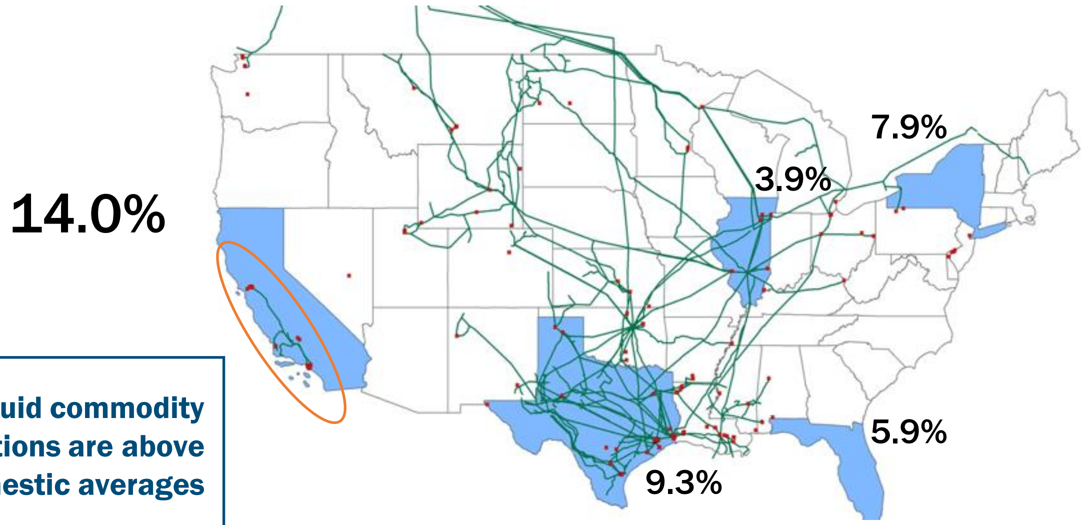
Source: CRC internal estimates. See www.crchbproperty.com for additional information.

Strong Commodity Price Realizations

- **Crude:** Crude indices experienced increased volatility during 2Q25 with prices slumping on ‘Liberation Day’ tariff announcements and OPEC returning offline production at a surprisingly increased pace, only to rally on Middle East military engagements. California realizations remained solid even with a continued (partial) outage at a major Bay Area refinery.
- **Natural Gas:** North American natural gas prices were slightly lower Q/Q while the California market labored under seasonally mild weather and a surplus of natural gas in storage.
- **NGLs:** Realizations for 2Q25 were seasonally lower Q/Q. California continues to carry a premium to the broader North American NGL marketplace. Our production is subject to virtually no impact related to US/Asian trade negotiations.

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

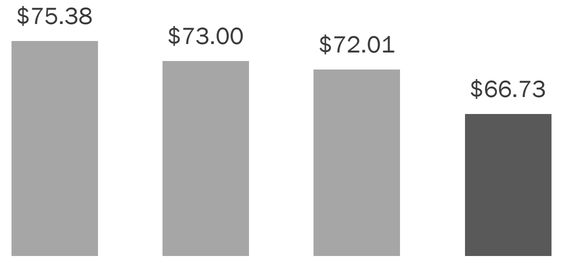
(amounts shown as % of U.S. domestic GDP)



CRC’s liquid commodity realizations are above domestic averages

Note: 5 largest contributors to domestic GDP. Source: BEA, preliminary data for 1Q25; EIA

Oil w/ Hedges ($/BBL)

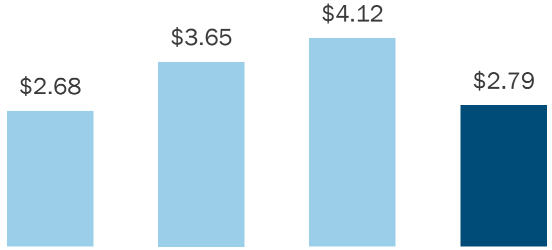


	3Q24	4Q24	1Q25	2Q25
Average Benchmark Prices[1]	$78.54	$73.97	$74.92	$66.76
% of Benchmark[1]	98%	98%	98%	97%
Hedge Settlements	($1.72)	$0.18	($1.56)	$1.66
Average Realized Prices[2]	$75.38	$73.00	$72.01	$66.73

NGLs ($/BBL)

	3Q24	4Q24	1Q25	2Q25
Average Benchmark Prices[1]	$78.54	$73.97	$74.92	$66.76
% of Benchmark[1]	58%	71%	73%	64%
Hedge Settlements	-	-	-	-
Average Realized Prices[2]	$45.77	$52.62	$54.64	$42.41

Natural Gas ($/MCF)



	3Q24	4Q24	1Q25	2Q25
Average Benchmark Prices[1]	$2.16	$2.79	$3.65	$3.44
% of Benchmark[1]	124%	131%	113%	81%
Hedge Settlements	-	-	-	-
Average Realized Prices[2]	$2.68	$3.65	$4.12	$2.79

See slide 32 for “Assumptions, Estimates and Endnotes”.

Hedge Portfolio (as of June 30, 2025)

OIL		3Q25E	4Q25E	1Q26E	2Q26E	2H26E	2027E	2028E
SOLD CALLS								
Brent	Barrels per Day	30,000	29,000	35,000	35,000	35,000	-	-
	Weighted-Average Price	$87.08	$87.13	$83.86	$83.86	$83.86	-	-
SWAPS								
Brent	Barrels per Day	45,001	43,376	36,444	29,399	28,036	34,382	1,697
	Weighted-Average Price	$70.63	$69.86	$68.98	$68.03	$67.25	$64.63	$65.00
PURCHASED PUTS[1]								
Brent	Barrels per Day	30,000	29,000	35,000	35,000	35,000	-	-
	Weighted-Average Price	$61.67	$61.72	$61.14	$61.14	$61.14	-	-
NATURAL GAS		**3Q25E**	**4Q25E**	**1Q26E**	**2Q26E**	**2H26E**	**2027E**	**2028E**
SWAPS								
SoCal Border	MMBtu per Day	25,750	22,408	20,350	13,250	10,329	-	-
	Weighted-Average Price	$3.48	$3.53	$5.18	$4.82	$4.84	-	-
NWPL Rockies[2]	MMBtu per Day	51,750	51,750	51,750	51,750	51,750	33,616	1,576
	Weighted-Average Price	$2.95	$4.22	$4.67	$3.64	$3.93	$4.12	$3.95
EST. HEDGE CONTRACT SETTLEMENTS[3]		**3Q25E**	**4Q25E**	**1Q26E**	**2Q26E**	**2H26E**	**2027E**	**2028E**
Combined Hedge Portfolio ($MM)		$16	$19	$12	$(0)	$7	($7)	$1

STRATEGY

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

EXECUTION

~69% of remaining 2025E net oil production hedged with an average Brent floor price of ~$67 per barrel

OPERATIONS

~67% of remaining 2025E internal fuel consumption hedged at an average natural gas price of ~$3.56 per MMBtu

See slide 32 for "Assumptions, Estimates and Endnotes".

Strong Balance Sheet, Ample Liquidity and Financial Flexibility

6/30/25 NET DEBT* SNAPSHOT

($MM)

Revolving Credit Facility (RCF)	$ -
7.125% 2026 Senior Notes	122
8.250% 2029 Senior Notes	900
Face Value of Debt	**$ 1,022**
Less Available Cash & Cash Equivalents[1]	(56)
Net Debt*	**$ 966**

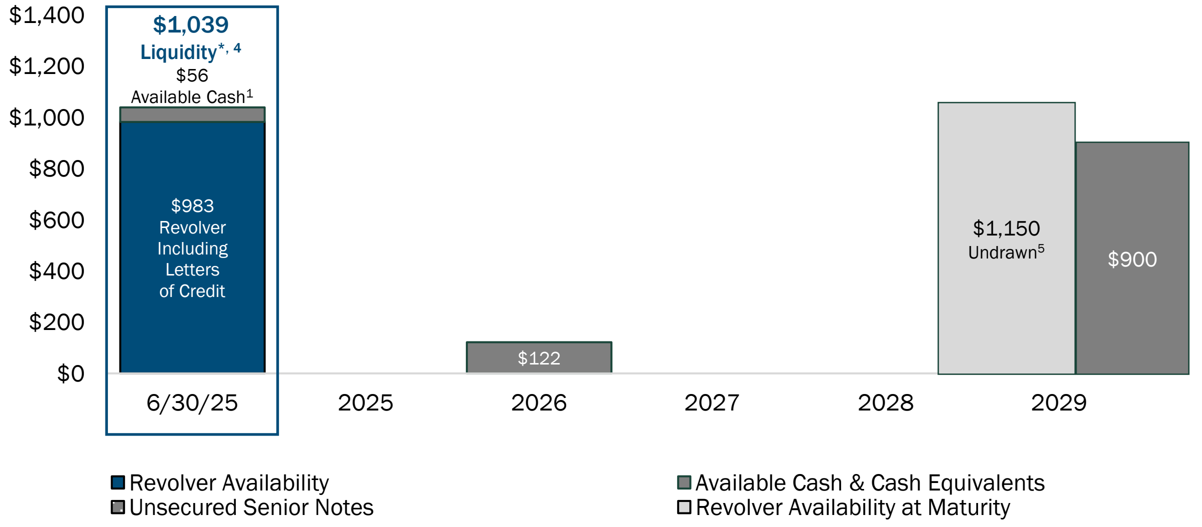
MULTIPLES DEMONSTRATE FLEXIBILITY

($MM)

RCF Borrowing Base	$1,500
2Q25 Free Cash Flow*	$109
2Q25 Net Debt* / LTM EBITDAX*, [2]	0.7x
LTM EBITDAX* / LTM Interest Expense*, [3]	12.6x

MATURITY PROFILE

($MM)



RECENT CREDIT UPDATES

- Redeemed $123MM of the 2026 Senior Notes in February 2025, targeting to act on the balance in 2025
- Borrowing base reaffirmed at $1.5B in April

See slide 32 for "Assumptions, Estimates and Endnotes".

Glossary

Term	Definition
Bcf	Billion Cubic Feet
BMT	Billion Metric Tons
BTM	Behind-the-Meter
CARB	California Air Resources Board
CCS	Carbon Capture and Storage
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)*
CUP	Conditional Use Permit
DAC	Direct Air Capture
D&C	Drilling and Completions
E&P	Exploration and Production
EBITDAX	Earnings Before Interest, Taxes, Depreciation, Amortization and Exploration
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
FID	Final Investment Decision
FTM	Front-of-the-Meter
G&A	General and Administrative
GHG	Greenhouse Gas
IRR	Internal Rate of Return
JV	Joint Venture

Term	Definition
KMTPA	Thousand Metric Tons Per Annum
LCFS	Low Carbon Fuel Standard
LTM	Last Twelve Months
MMT	Million Metric Tons
MMTPA	Million Metric Tons Per Annum
MOU	Memorandum of Understanding
MRV	Monitoring, Reporting and Verification Plan
MT	Metric Tons
MTPA	Metric Tons Per Annum
NG	Natural Gas
NGL	Natural Gas Liquid
NRI	Net Revenue Interest
OCF	Operating Cash Flow
PDP	Proved Developed Producing
PDNP	Proved Developed Non-Producing
PPA	Power Purchase Agreement
PUD	Proved Undeveloped
RA	Resource Adequacy
ROFL	Right of First Look
RSG	Responsibly Sourced Gas
R/P	Reserves to Production Ratio
RTC	Round-the-Clock
SFDR	Sustainable Finance Disclosure Regulation
SMOG	Standardized Measure of Discounted Future Net Cash Flows
SRP	Share Repurchase Program
SJV	San Joaquin Valley
TBA	To Be Announced
Tcf	Trillion Cubic Feet
WI	Working Interest

Assumptions, Estimates and Endnotes

Slide 2:
(1) All CRC's future quarterly dividends and share repurchases are subject to commodity prices, debt agreement covenants and Board of Directors approval. Excludes excise taxes and commissions paid on share repurchases.
(2) Total year 2025E guidance assumes a 2025E Brent price of $68.00 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.65 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 12 for 2025E guidance.

Slide 4:
(1) All CRC's future quarterly dividends and share repurchases are subject to commodity prices, debt agreement covenants and Board of Directors approval. Excludes excise taxes and commissions paid on share repurchases.
(2) Source: FactSet. Represents current annual dividend policy of $1.55 per share divided by CRC's market capitalization as of August 1, 2025.

Slide 5:
(1) Includes gas processing costs.
(2) CMB expenses are included in other operating expenses, net in our condensed consolidated statement of operations.

Slide 6:
(1) NPV at 10% reflects the net present value of all synergies implemented to date, discounted at a 10% rate. The calculation assumes all realized synergies, except interest synergies, are sustainable over a 10-year period and excludes both costs to achieve the savings and taxes. Interest expense synergies are assumed to expire in 2029 on the expectation that the refinanced Aera-related indebtedness is repaid at maturity in 2029.

Slide 7:
(1) Source: CRC internal estimates. Project economics reflect available inventory supported by permits in hand.
(2) Total year 2025E guidance assumes a 2025E Brent price of $68.00 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.65 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 12 for 2025E guidance.

Slide 8:
(1) 2Q25E guidance assumes a 2Q25E Brent price of $63.00 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $4.11 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline.
(2) Other operating expenses net of other revenue is calculated as the difference between other revenue and other operating expenses, net and includes exploration expense and CMB expenses. CMB expenses includes lease cost for sequestration easements, advocacy, and other startup related costs. We have updated this caption for better alignment to our condensed consolidated statements of operations.
(3) Margin from purchased commodities is calculated as the difference between revenue from marketing of purchased commodities and costs related to marketing of purchased commodities, and excludes costs of transportation
(4) Electricity margin is calculated as the difference between electricity sales and electricity generation expenses.
(5) All CRC's future quarterly dividends and share repurchases are subject to commodity prices, debt agreement covenants and Board of Directors' approval. Excludes excise taxes and commissions paid on share repurchases.

Slide 9:
(1) Free cash flow before net changes in operating assets and liabilities is calculated as net cash provided by operating activities before net changes in operating assets and liabilities* minus capital investments. Net cash provided by operating activities before net changes in operating assets and liabilities* is a non-GAAP number. Please see the Investor Relations page at www.crc.com for a reconciliation of net cash provided by operating activities before net changes in operating assets and liabilities to the nearest GAAP equivalent and other additional information.
(2) As of CRC 4Q24 earnings results announcement on March 3, 2025.
(3) As of CRC 2Q25 earnings results announcement on August 5, 2025.

Slide 11:
(1) Costs includes operating costs, CMB expenses which are included in other operating expenses, net, G&A expenses, electricity generation expenses, costs related to marketing of purchased commodities, transportation costs and taxes other than on income. Management's understanding and control of its cost structure is essential for profitability and efficiency. It informs resource and people allocation decisions, while identifying areas for cost reduction.
(2) Total year 2025E guidance assumes a 2025E Brent price of $68.00 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.65 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 12 for 2025E guidance.

Slide 12:
(1) Margin from purchased commodities is calculated as the difference between revenue from marketing of purchased commodities and costs related to marketing of purchased commodities, and excludes costs of transportation.
(2) Electricity margin is calculated as the difference between electricity sales and electricity generation expenses.
(3) Other operating expenses net of other revenue is calculated as the difference between other revenue and other operating expenses, net and includes exploration expense and CMB expenses. CMB expenses includes lease cost for sequestration easements, advocacy, and other startup related costs.

Assumptions, Estimates and Endnotes (Cont.)

Slide 15:
(1) Reserves estimated as of December 31, 2024 using SEC Prices of \$80.42 per barrel for oil and \$2.13 per MMbtu for natural gas.
(2) Calculated using annualized 4Q24 net production.
(3) CRC data from internal estimates. Peer data from Enverus as of July 2, 2025. Peers include BRY, CIVI, FANG, HPK, MGY, MTDR, PR, REI, REPX and SM.

Slide 16:
(1) Source: EPA, www.epa.gov/uic/class-vi-wells-permitted-epa. “Permit Volumes” refers to carbon storage shown in EPA Class VI permits that CTV has received or submitted. The actual volumes that CTV may ultimately store may differ from the permit volumes as additional technical and commercial data is acquired and evaluated. Injection rates are average rates based on estimated maximum permit volumes over the assumed life of project. Actual volumes and the injection period may vary over time.
(2) See CRC’s 2Q22 earnings presentation for additional details on Brookfield's initial commitment of up to \$500MM to invest in CCS projects that are jointly approved through the Carbon TerraVault JV.
(3) Source: Database of State Incentives for Renewables & Efficiency (DSIRE) from the N.C. Clean Energy Technology Center.
(4) Based on internal estimates of total resources located in California, and includes resources not owned by CRC.

Slide 17:
(1) Source: California Air Resources Board, "Current California GHG Emission Inventory Data 2000–2022," 2024.
(2) Source: California Energy Commission.

Slide 18:
(1) Source: EPA, www.epa.gov/uic/class-vi-wells-permitted-epa. “Permit Volumes” refers to carbon storage shown in EPA Class VI permits that CTV has received or submitted. The actual volumes that CTV may ultimately store may differ from the permit volumes as additional technical and commercial data is acquired and evaluated. Injection rates are average rates based on estimated maximum permit volumes over the assumed life of project. Actual volumes and the injection period may vary over time.
(2) 26R injection volumes as per the draft EPA permit is ~38MMT. Assuming the maximum expected injection rate of 1.46MMTPA, the reservoir would reach permitted volumes in 26 years. Each CTV reservoir will have a unique set of operating, injection and life span parameters that will vary and will be reflected on the submitted permit.
(3) Source: CARB 2020.

Slide 19:
(1) Source: EPA, www.epa.gov/uic/class-vi-wells-permitted-epa. Based on EPA estimates and approvals. CTV I A1-A2 and CTV II are projected to receive a final permit decision in February 2026, CarbonFrontier, CTV III, and CTV IV are projected to receive a final permit decision in March 2026, CTV V is projected to receive a final permit decision in May 2026, and CTV VI is projected to receive a final permit decision in November 2026.

Slide 21:
(1) Assumes the average capital needs for 5MMTPA of Carbon Sequestration from the CTV JV economic “Type Curve”. See slide 19 and 20 from CRC’s 1Q23 Earnings Presentation for detailed information on the previously disclosed Type Curve. Brookfield made an initial commitment of \$500 million to invest in CCS projects that are jointly approved through the Carbon TerraVault JV. The partnership is targeting 5MMTPA of CO2 injection by YE 2027, aligned with CRC’s 2027 goals, thereby requiring an estimated ~\$2.5B of capital.
(2) ~\$980MM assumes 200MMT of CO2 pore space for \$10/MT of CO2 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 CO2 storage.
(3) Results subject to effects of taxes, timing, pace of project development and Brookfield further approval to fund capital.

Slide 22:
(1) Note: Diagram for illustrative purposes only.
(2) Commitment applies to CCS projects that are jointly approved through the JV.
(3) (2) Assumes Brookfield fully participates in CCS projects up to JV target of 5 MMTPA of injection and 200MMT of CO2 storage
(4) (3) Additionally, CRC will provide operational and other services to the joint venture.
(5) (4) Independent of Infrastructure Co.

Slide 23:
(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 its Elk Hills Power Plant.

Slide 24:
(1) MOUs and CDMAs are non-binding agreements. The projects and transactions described in an MOU or CDMA are subject to certain conditions precedent, typically including the negotiation of definitive documents, a final investment decision by the parties and receipt of EPA Class VI permits and other regulatory approvals.

Assumptions, Estimates and Endnotes (Cont.)

Slide 26:
- (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 certain of our natural gas related to marketing activities.

Slide 27:
- (1) Purchased and sold puts with the same strike price have been netted together.
- (2) NPWL volumes require transportation to where the gas is consumed. These costs are reflected in our 2025E transportation guidance. See slide 12 for 2025E guidance.
- (3) Represents estimated net cash settlement payments inclusive of premiums for derivative contracts and forward commodity prices as of June 30, 2025.

Slide 28:
- (1) Available cash and cash equivalents excludes $16MM of restricted cash.
- (2) Net leverage is calculated as 2Q25 net debt of $966MM (excludes restricted cash of $16MM) divided by LTM adjusted EBITDAX of $1,370MM.
- (3) Interest coverage is calculated as LTM adjusted EBITDAX of $1,370MM and LTM interest expense of $109MM.
- (4) Liquidity on June 30, 2025 is calculated as $56MM of cash and cash equivalents (excluding $16MM of restricted cash) plus $1,150MM of borrowing capacity on CRC's Revolving Credit Facility less $167MM in outstanding letters of credit.
- (5) Undrawn Revolving Credit Facility as of June 30, 2025, excluding outstanding letters of credit.

Forward – Looking / Cautionary Statements – Certain Terms

Forward-Looking Statements:

This document contains statements that CRC believes to be "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than historical facts are forward-looking statements, and include statements regarding CRC's future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and plans and objectives of management for the future. Words such as "expect," "could," "may," "anticipate," "intend," "plan," "ability," "believe," "seek," "see," "will," "would," "estimate," "forecast," "target," "guidance," "outlook," "opportunity" or "strategy" or similar expressions are generally intended to identify forward-looking statements. These 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 CRC believes the expectations and forecasts reflected in its 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 its 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 CRC's actual results to be materially different than those expressed in its forward-looking statements are described in its most recent Annual Report on Form 10-K and its other periodic filings with the Securities and Exchange Commission. These factors include, but are not limited to: fluctuations in commodity prices; production levels and/or pricing by OPEC, OPEC+ or U.S. producers; government policy, war and political conditions and events; integration efforts and projected benefits in connection with the Aera Merger and other acquisitions, divestitures and joint ventures; regulatory actions and changes that affect the oil and gas industry generally and us in particular; the efforts of activists to delay prevent oil and gas activities or the development of CRC's carbon management segment; changes in business strategy and capital plan; lower-than-expected production; changes to estimates of reserves and related future cash flows; the recoverability of resources and unexpected geologic conditions; general economic conditions and trends; results from operations and competition in the industries in which it operates; CRC's ability to realize the anticipated benefits from prior or future efforts to reduce costs; environmental risks and liability; the benefits contemplated by its energy transition strategies and initiatives; CRC's ability to successfully identify, develop and finance carbon capture and storage projects, power projects and other renewable energy efforts; future dividends and share repurchases and de-leveraging efforts; and natural disasters, accidents, mechanical failures, power outages, labor difficulties, cybersecurity breaches or attacks or other catastrophic events.

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

Non-GAAP Financial Measures:

This presentation contains certain financial measures that are not prepared in accordance with generally accepted accounting principles ("GAAP"). These measures are identified with an "*" and include but are not limited to Adjusted EBITDAX, Operating Cash Flow Before Net Changes in Operating Assets and Liabilities, PV-10, Leverage Ratio, Net Debt, Liquidity and Free Cash Flow. 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.

Industry and Market Data:

This presentation has been prepared by CRC and includes market data and other statistical information from sources it believes to be reliable, including independent industry publications, governmental publications or other published independent sources. Some data is also based on our good faith estimates, which are derived from CRC's review of internal sources as well as the independent sources described above. Although CRC believes these sources are reliable, it has not independently verified the information and cannot guarantee its accuracy and completeness. CRC owns or has rights to various trademarks, service marks and trade names that it uses in connection with the operation of its business. This presentation also contains trademarks, service marks and trade names of third parties, which are the property of their respective owners. CRC's use or display of third parties' trademarks, service marks, trade names or products in this presentation is not intended to, and does not imply, a relationship with CRC or an endorsement or sponsorship by or of CRC.

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Higher **Cashflow**

Less **Carbon**

Better **California**

A DIFFERENT KIND OF ENERGY COMPANY