

Corporate Presentation

November 2026

CALIFORNIA RESOURCES

California's Leading Energy Infrastructure Platform

- 4th Largest Economy in the World and 2nd Largest Consumer of Energy in the U.S.[1]
- Historical Increase in Reliance on Energy Imports, While Local Production has Declined
- Unique Supply and Demand Dynamics Drive Premium Energy Price Environment

CRC's California Energy Portfolio

~23 Years[2] 2P Reserve Life Index	**~147MBoe/d**[3] 2026E CA Net Production (~80% Oil)	**~1.9MM** Mineral Acres
~400Mbo/d Crude Oil Transportation Capacity	**~350MMcf/d** Natural Gas Transportation Capacity	**>5MMBbls** Total Liquids Storage Capacity
Nearly **~1GW** Power Generation Capacity	Up to **~18MMTPA**[4] EPA Class VI CO_2 Permit Volumes Submitted	First **CCS Project**[5] In California

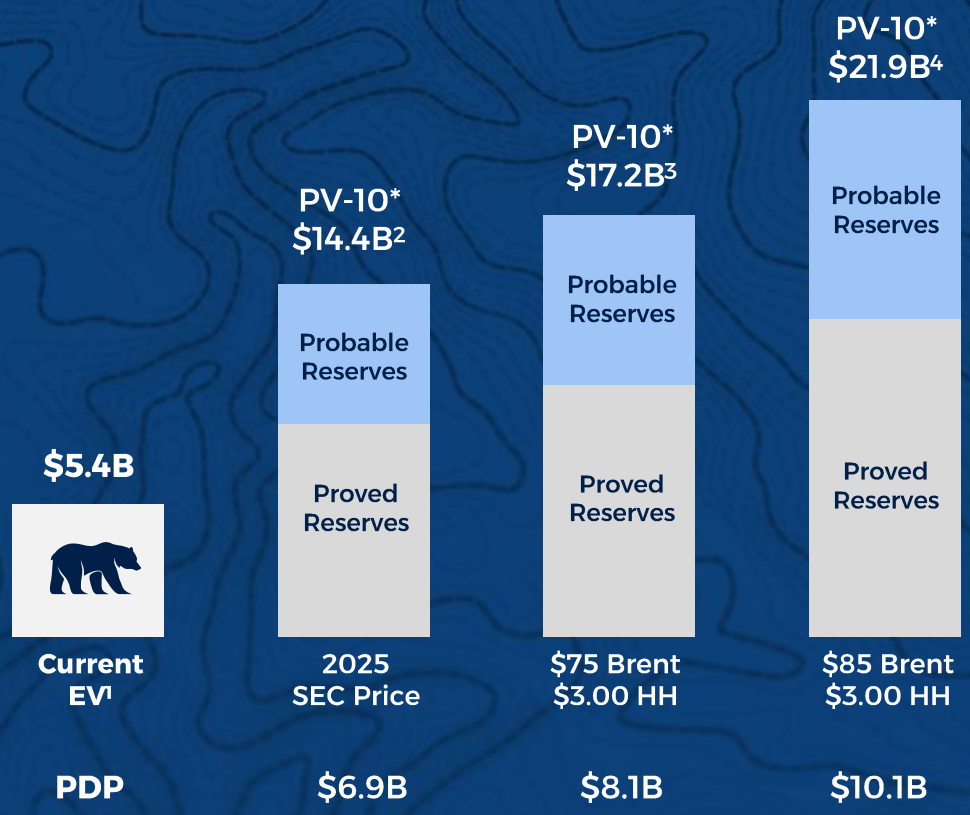
See slide 40 for "Assumptions, Estimates and Endnotes".

Integrated Assets Across the Energy Value Chain



Significant Value From World-Class Conventional Reservoirs

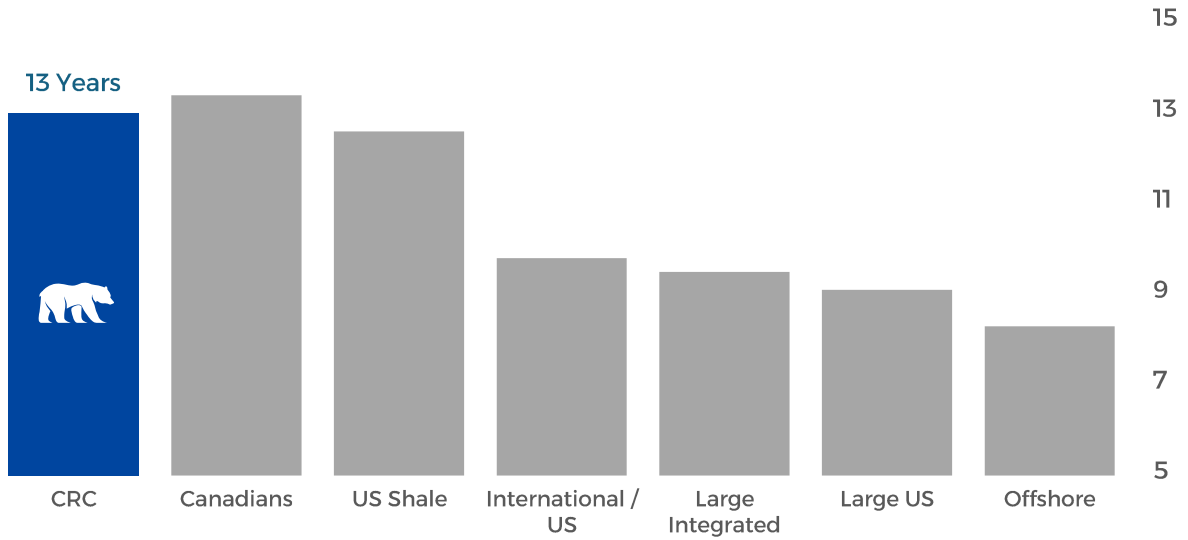
Material Upside From Long Duration Assets



See slides 40 and 41 for "Assumptions, Estimates and Endnotes".

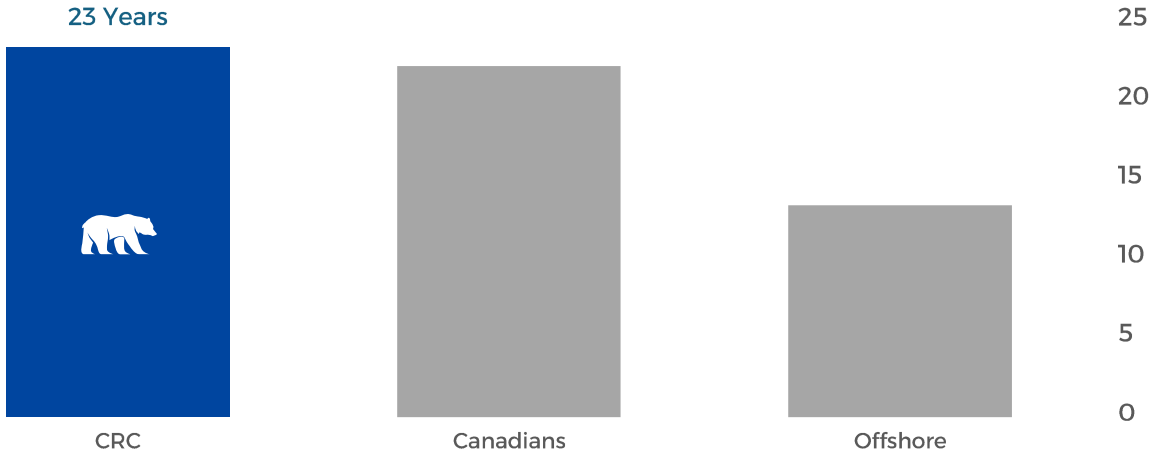
Long Proved Reserves Base

Proved Reserves / Annual Production (Years)[5]



Multi-Decade Conventional Runway

Proved + Probable Reserves / Annual Production (Years)[5]



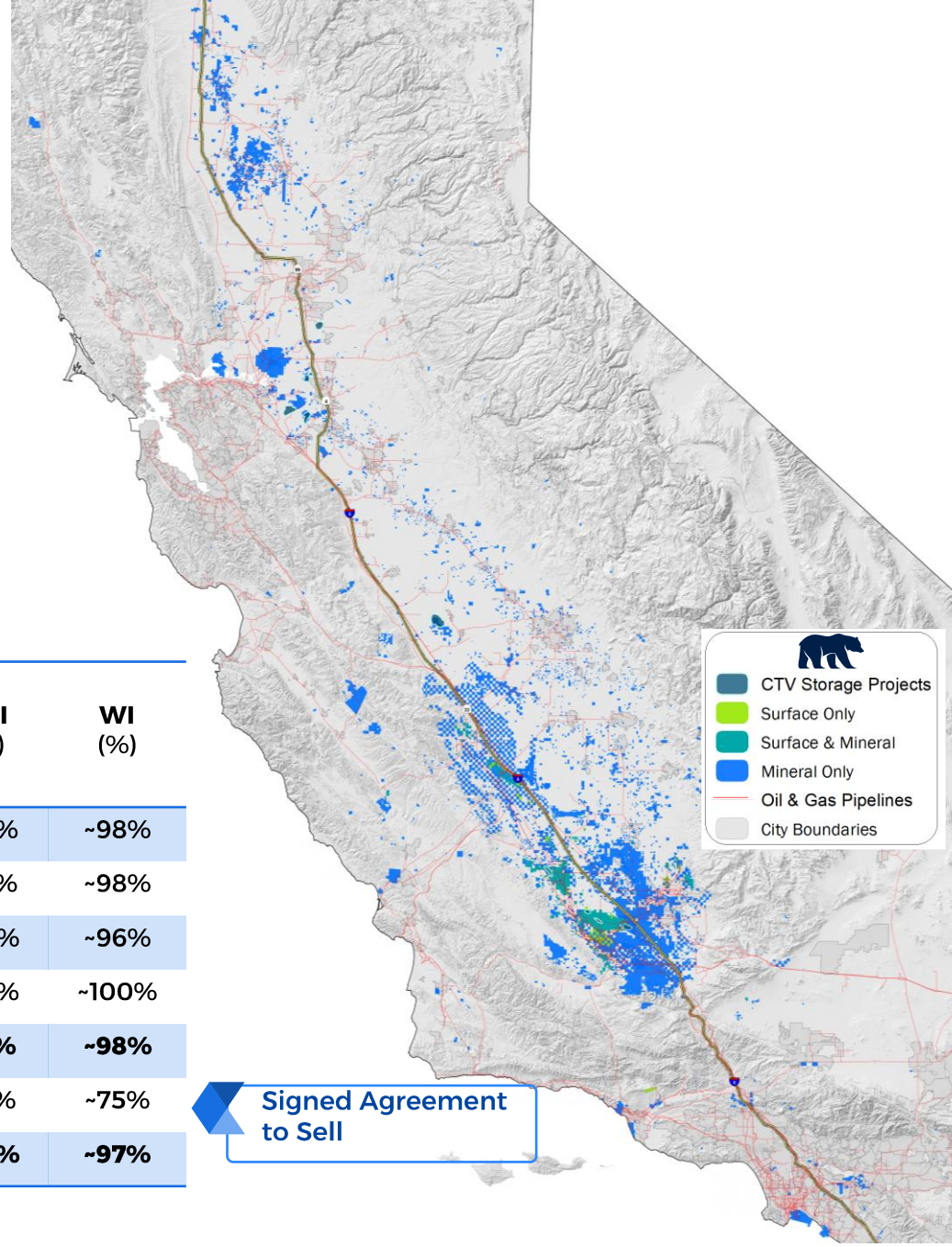
Premier California Energy Company

CRC's Advantaged Portfolio Characteristics

- Geographic Advantage
- High-Quality, Low-Decline Assets
- Robust Development Inventory
- Ready for Growth
- Superior Economics
- Existing O&G Midstream Network

CRC's Long Runway 1P Asset Inventory[1]

Basin/Unit	PD[2] (%)	Total Proved (MMBOE)	Oil (%)	Est. Annual Corporate PDP Decline (%)	R/P[3] (Years)	Surface Acreage ('000)	Mineral Acreage ('000)	NRI (%)	WI (%)
San Joaquin	84%	529	81%	~11%	13	~206	~1,304	~94%	~98%
Los Angeles	98%	65	98%	~7%	10	<1	~36	~72%	~98%
Sacramento	100%	1	0%	~9%	1	<1	~418	~80%	~96%
Other California	85%	27	93%	~11%	8	~3	~130	~86%	~100%
Total California	**86%**	**622**	**83%**	**~11%**	**12**	**~210**	**~1,888**	**~91%**	**~98%**
Uinta	19%	32	81%	~19%	18[4]	~2	~98	~61%	~75%
Total Company	**83%**	**654**	**83%**	**~11%**	**13**	**~212**	**~1,986**	**~89%**	**~97%**



See slide 41 for "Assumptions, Estimates and Endnotes".

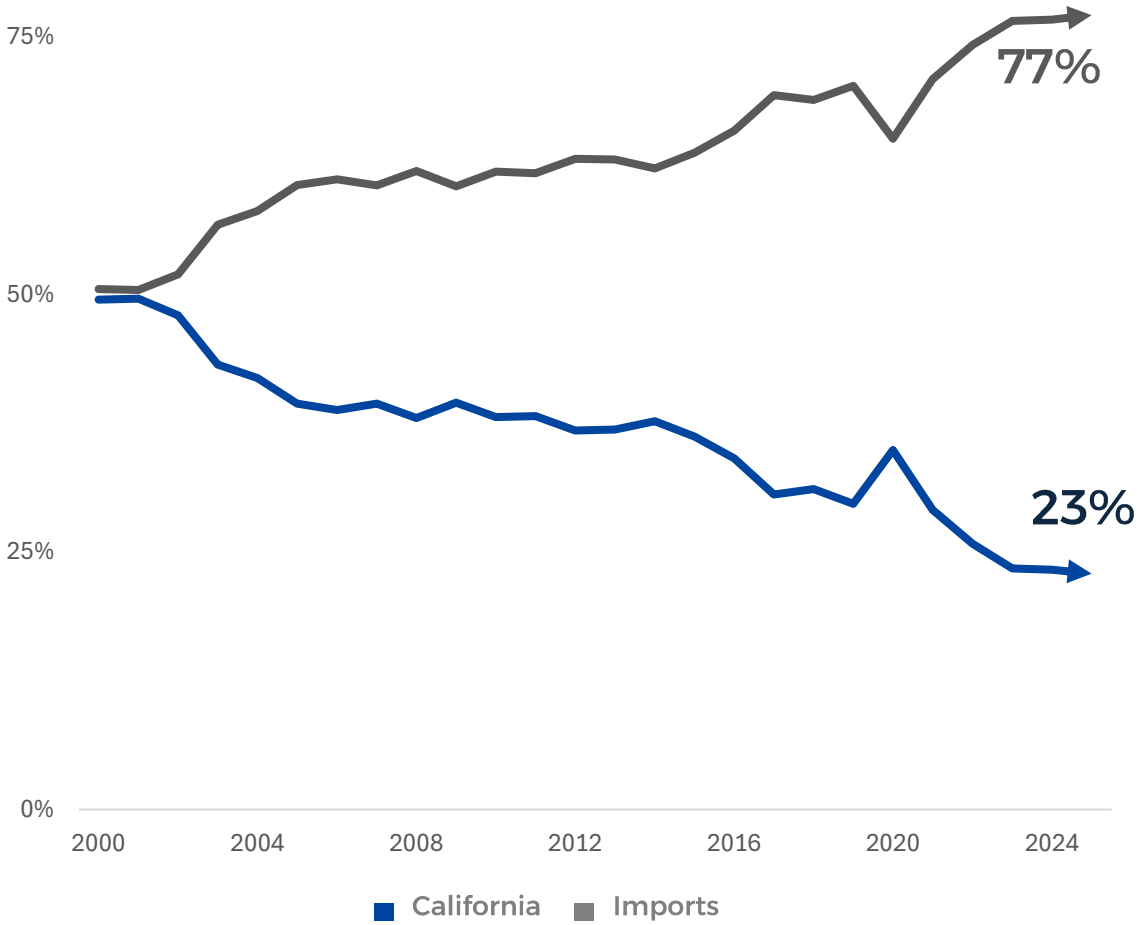
California's Energy Landscape

- **Second Largest Consumer of Energy in the U.S.[1]**
- **Highly Dependent on Energy Imports**
- **One of the Highest-Cost Energy Markets in the U.S.**
- **Needs Affordable, Clean and Reliable, Local Energy Production**
- **CRC is Built for California**

See slide 41 for "Assumptions, Estimates and Endnotes".

California Relies Heavily on Imported Oil

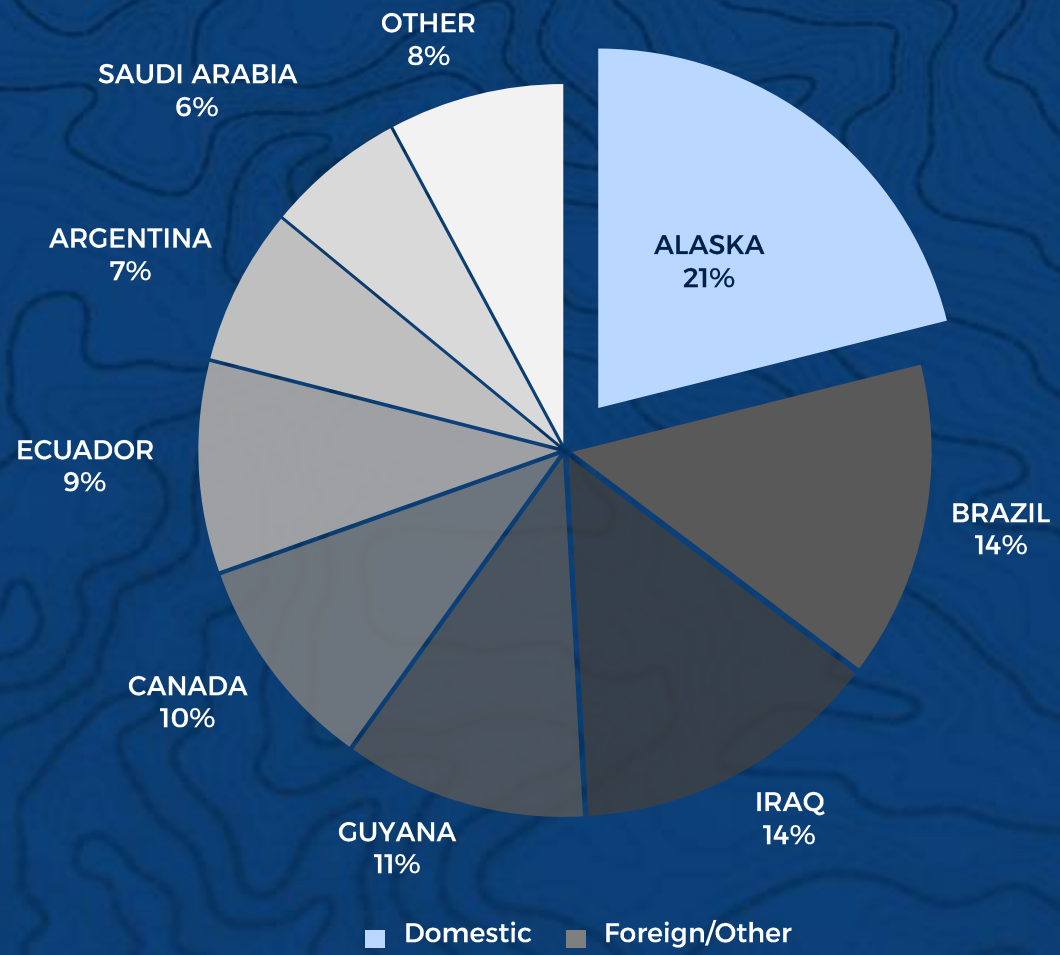
Annual Oil Supply Sources to California Refineries[1]
(2000 – 2025)



See slide 41 for "Assumptions, Estimates and Endnotes".

~80% of Oil Imports Came from Foreign Sources

2025 Sources of Crude Oil Imports to California[1]

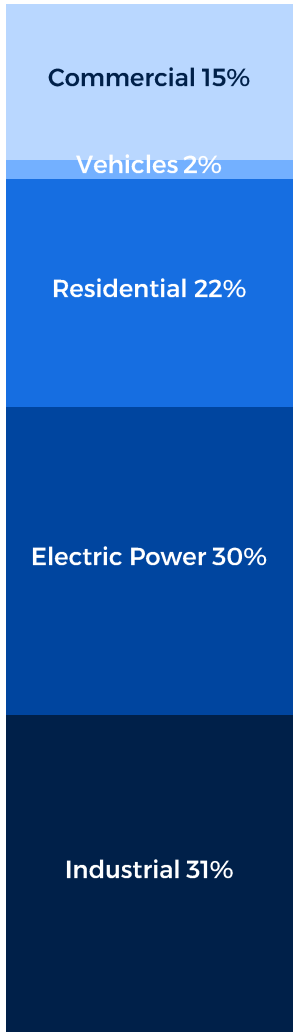


California Imports Over 90% of its Natural Gas Supply

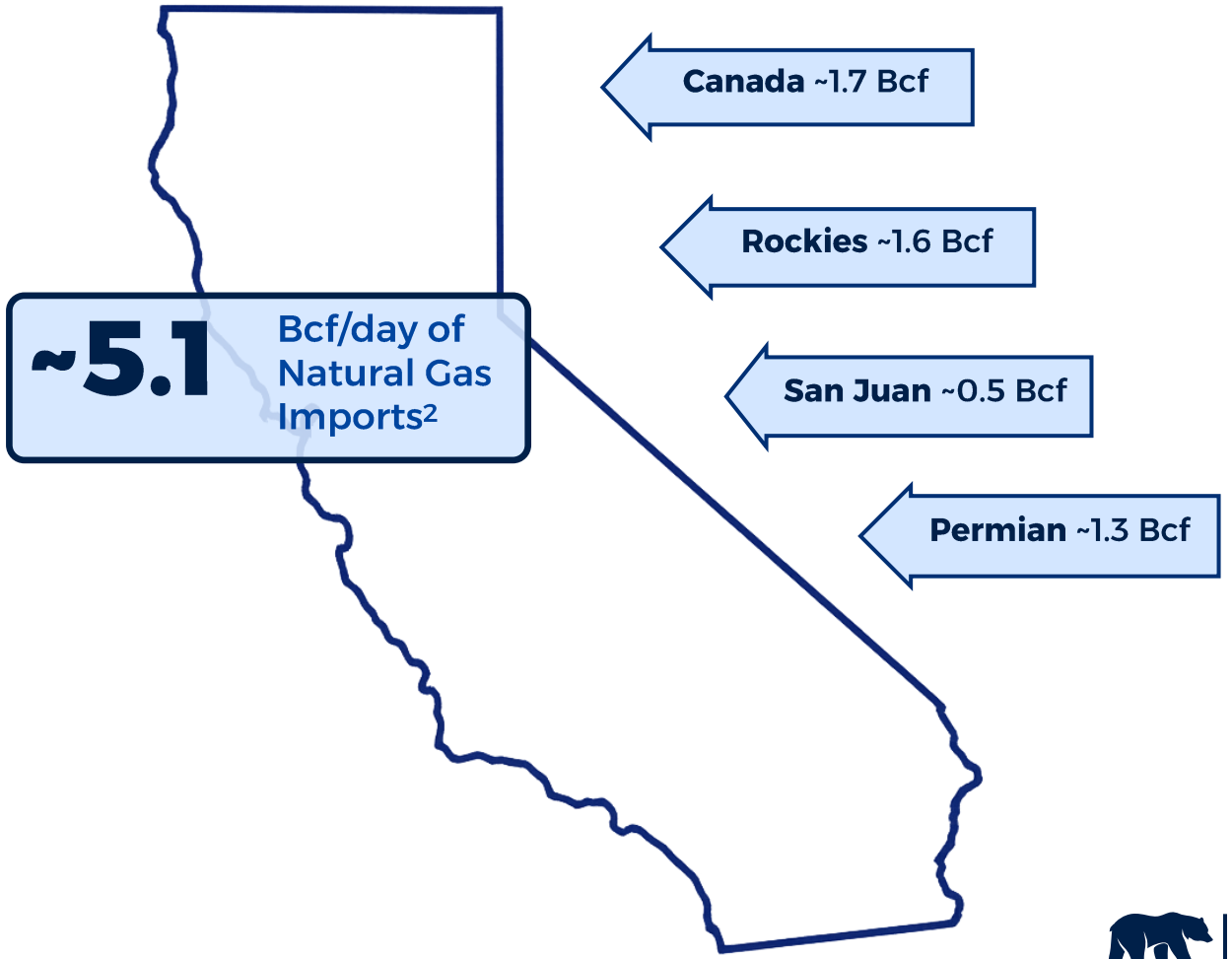
California is the nation's **third largest** consumer of natural gas

~5.3 Bcf/day of Natural Gas[1]

California Natural Gas Consumption by End Use[1]

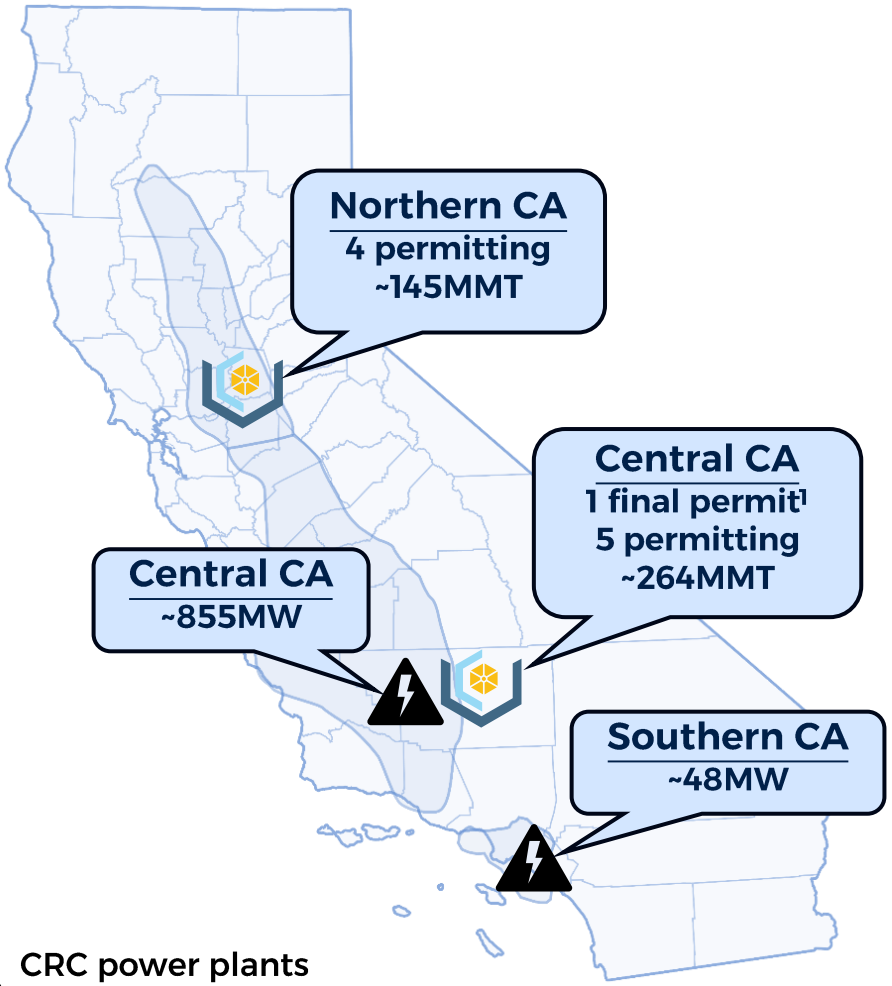


...and imports the **majority** of natural gas from unconventional basins



See slide 41 for "Assumptions, Estimates and Endnotes".

CRC Offers Affordable, Reliable & Lower Carbon Power Solutions



CRC power plants

CTV storage sites

CALIFORNIA RESOURCES

Nearly

~1-GW

Generation Capacity Access

- Active participant in California's power market through industrial and RA capacity sales
- Operating 855MW near CTV carbon capture facilities in San Joaquin Valley[2]
- Partnerships with main power providers in the area with grid connectivity
- Ability to deliver FTM or BTM power solutions

CARBON TERRAVAULT

350+

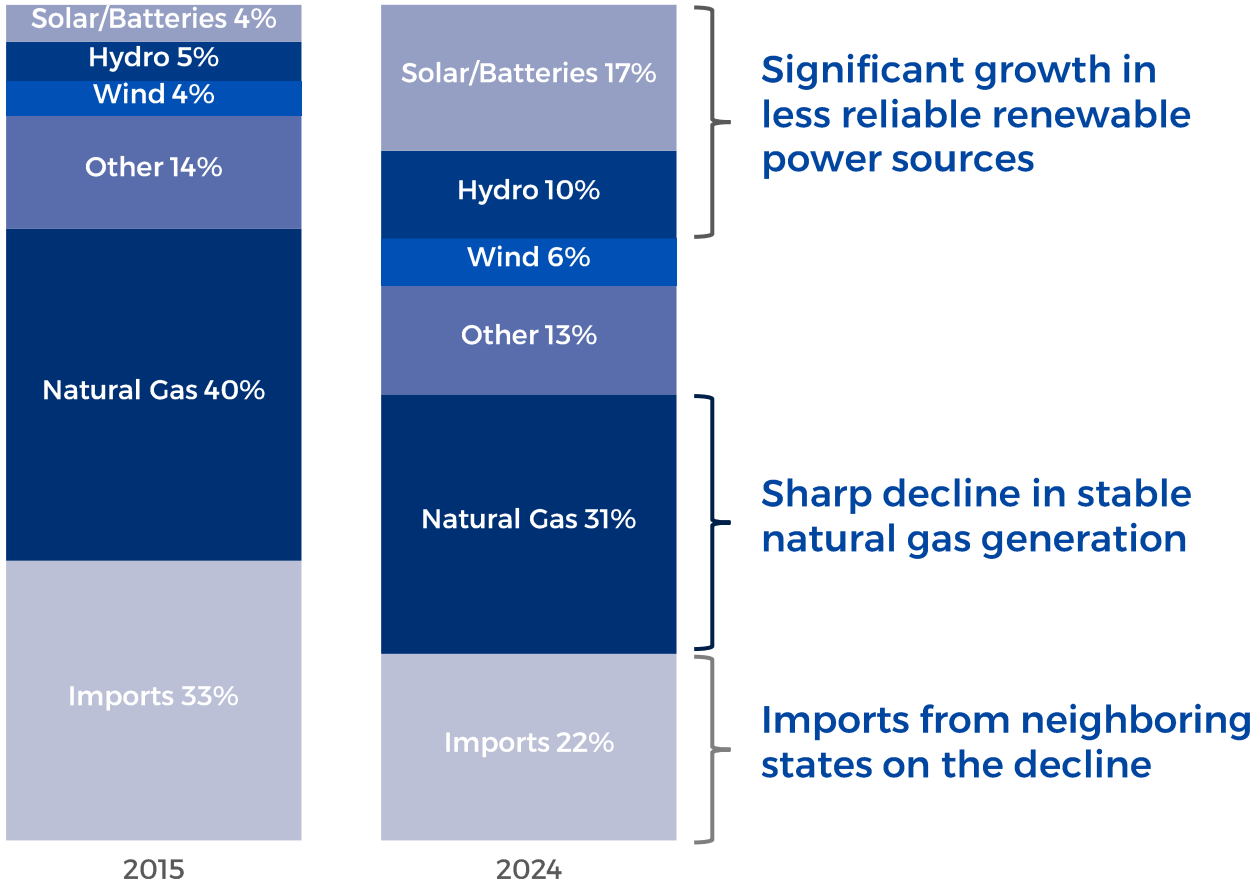
MMT Permit Volumes Submitted to EPA

- First CCS project in California[1]
- 9 vaults in permitting phase
- Opportunity to decarbonize ~18GW of underutilized natural gas power plants in CA
- Access to ~2.4GW[3] of power capacity in Kern County for a "Power-to-CCS" opportunity with AI Data Centers

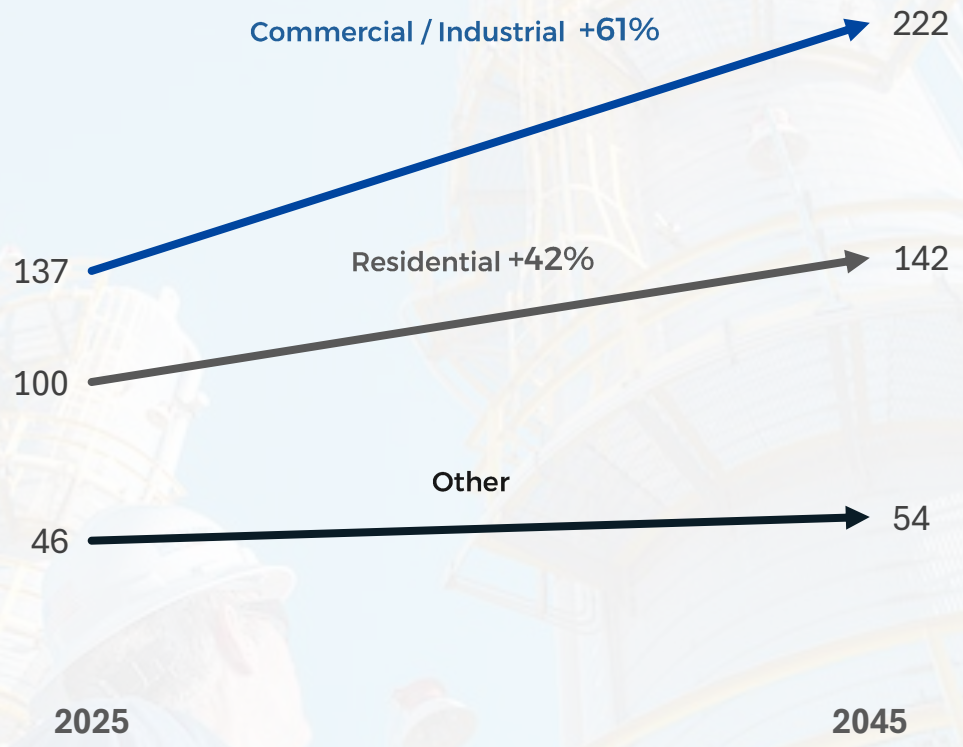
See slide 42 for "Assumptions, Estimates and Endnotes".

California's Power Demand Expected to Outpace Supply

California's Power Supply by Source[1]



California's Electricity Demand Outlook (000's GWh)[1]



See slide 42 for "Assumptions, Estimates and Endnotes".



3Q26 Results

Strengthening California's Leading Energy Infrastructure Platform

Enhancing Our California Core

- Strong reservoir performance driving ~2% sequential net production growth
- Announced an agreement to divest Uinta Basin assets
- Closed all-cash acquisition of Crimson which includes key rights-of-way that help build a foundation for a potential statewide CO_2 pipeline system[1]

Expanding Our Leading Carbon Management Business

- Signed MOU[2] with Bloom Energy for development of 1GW or more of clean power and storage of up to 3MMTPA of CO_2 emissions
- Submitted new EPA Class VI permit application for ~57MMT of CO_2 emissions bringing total submitted EPA Class VI permit volumes to ~409MMT[3]

Commitment to Shareholder Returns

- $66MM returned to shareholders in 3Q26 including $30MM in share repurchases and $36MM in dividends; ~45% of quarterly free cash flow*, [4]
- ~4% increase in quarterly dividend to $0.42 per share; ~3.0% annual dividend yield vs. peer average of ~1.8%[4, 5]

3Q26 Results Highlights

152MBoe/d
Total Net Production
~80% Oil

$158MM
Total Capital
$155MM E&P

$341MM
Adj. EBITDAX*

$300MM
Cash Flow Before W/C*

BLOOM
1GW or More and
3MMTPA MOU[2]

~57MMT
New EPA Class VI
Permit Submitted[3]

$66MM
Total Shareholder
Returns[4]

~4%
Quarterly Dividend
Increase[4]

Note: "Before WC Changes" means "Before Net Changes in Operating Assets and Liabilities".
See slide 42 for "Assumptions, Estimates and Endnotes".

California Focused

Closed Crimson Acquisition

Accretive	Attractively Priced	Industrial Logic
4.4x EV/27E Adj. EBITDA*, 1	~$63MM Cash[2]	Strong Asset Fit

- ~2,000-mile Crimson diversified midstream system and storage to link Central California production to highest-value markets and other growth opportunities
- Deal includes: SoCal Pipeline Network, IVEC Line, San Pablo Bay Pipeline, KLM Pipeline and other strategic assets
- Transaction includes any proceeds from pending rate cases
- Acquisition includes land rights that help build a foundation for the long-term development of a potential CO_2 pipeline system[3]
- Targeting the re-opening of San Pablo Bay Pipeline in 1Q27

CALIFORNIA RESOURCES × Crimson Midstream, LLC

Announced the Divestiture of Non-Core Uinta Basin[4]

Strategic Sale	Attractively Priced	CRC Focus
Unconventional Asset	~$90MM Cash[5]	California

- Accretive sale to cost structure and capital: Capital reallocation toward shareholder returns and other corporate purposes
- ~0.5% estimated improvement to corporate Brent-linked oil realizations
- Initial purchase price to be adjusted based on an economic effective date of July 1, 2026 (other than for certain items) and other transaction and closing costs[5]
- Closing expected by year-end 2026, subject to customary closing conditions

Unlocking Capital

Net Mineral Acres: ~100,000 acres
1H26 Oil Realization: ~79% of WTI
Net Revenue Interest: ~61%
1H26 Operating Cost/Boe: ~$26/Boe
Total ARO Liability: ~$32MM



Reallocated Uinta 2026E D&C Capital[6]

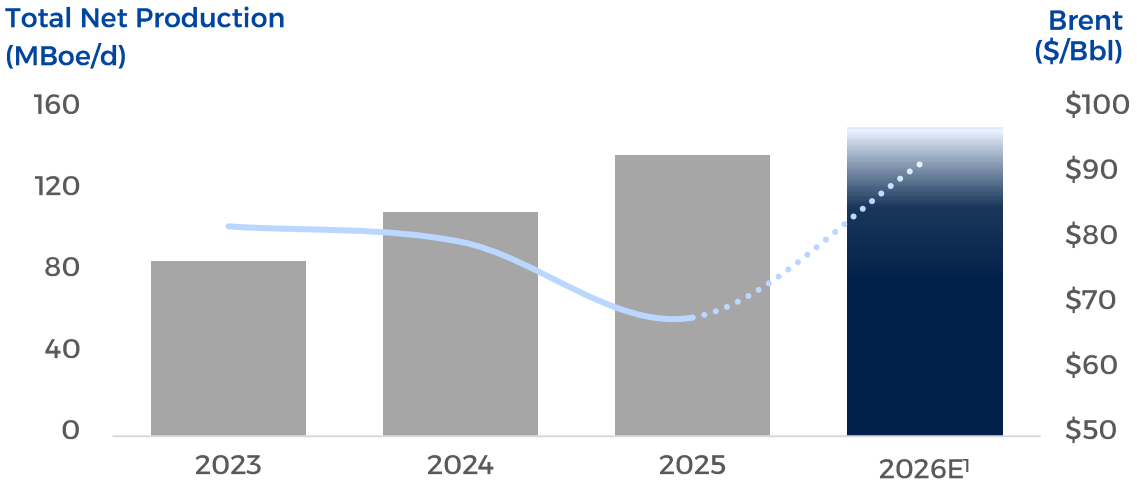
Initial Purchase Price[5]

Potential Unlocked Funds

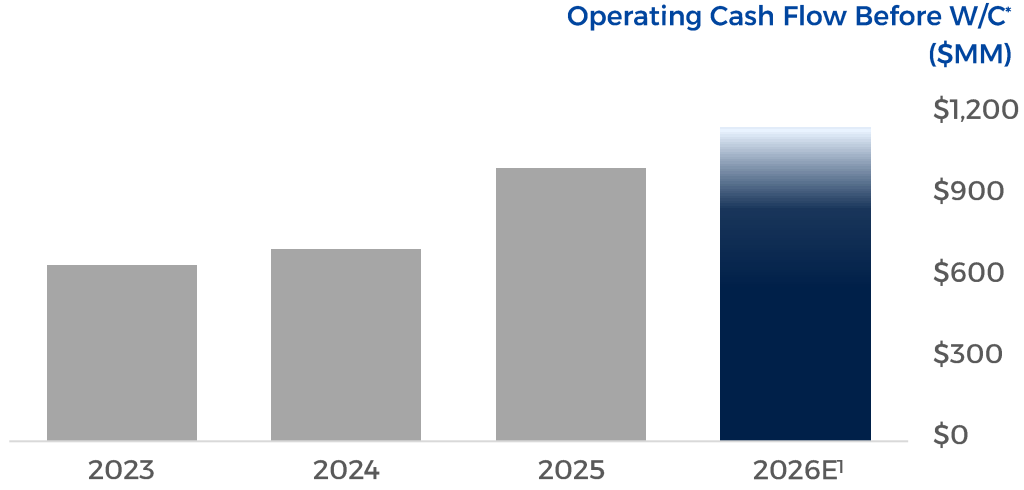
See slide 42 for "Assumptions, Estimates and Endnotes".

Building Momentum Through Year-End 2026

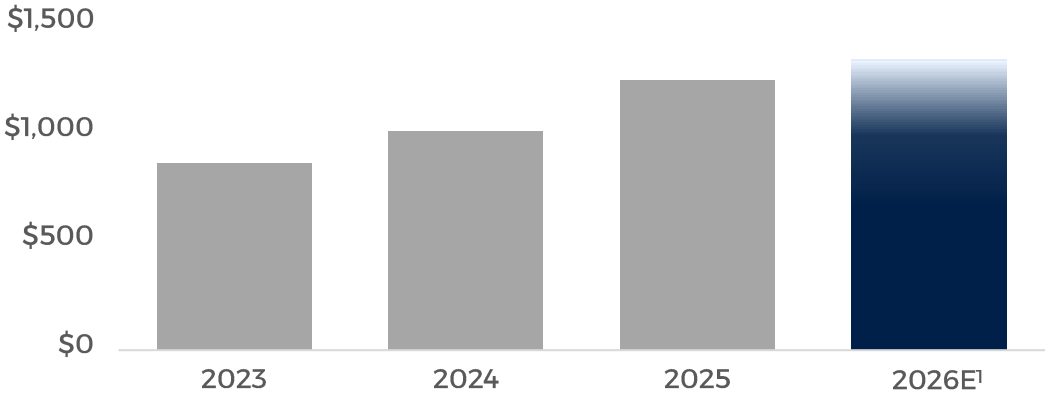
Added Production in Lower Price Environments



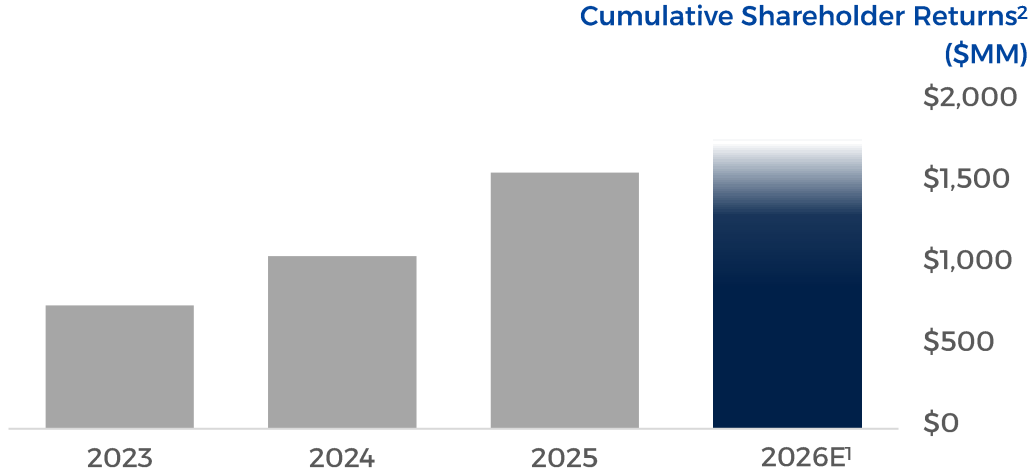
Robust Cash Flow Growth



Driving a ~15% Earnings CAGR



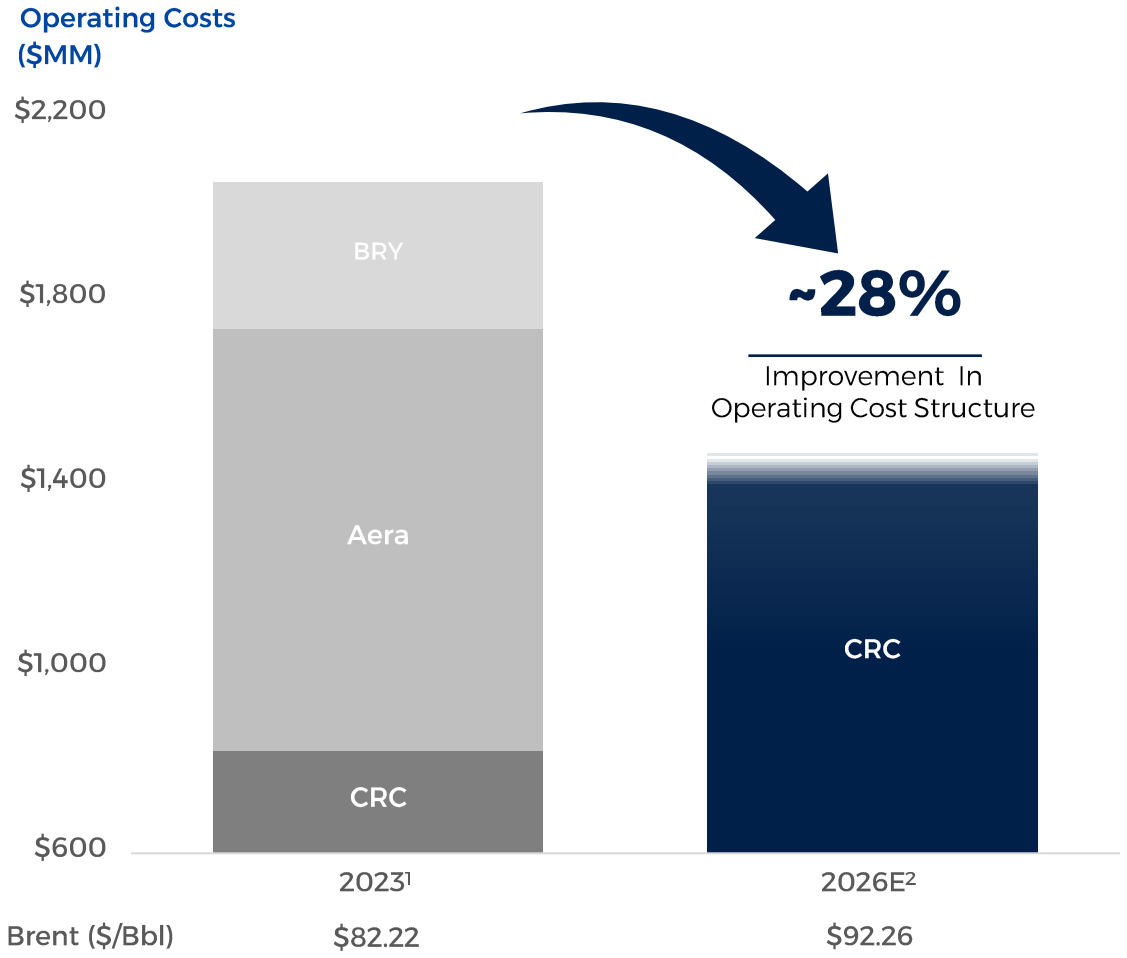
Commitment to Shareholder Returns

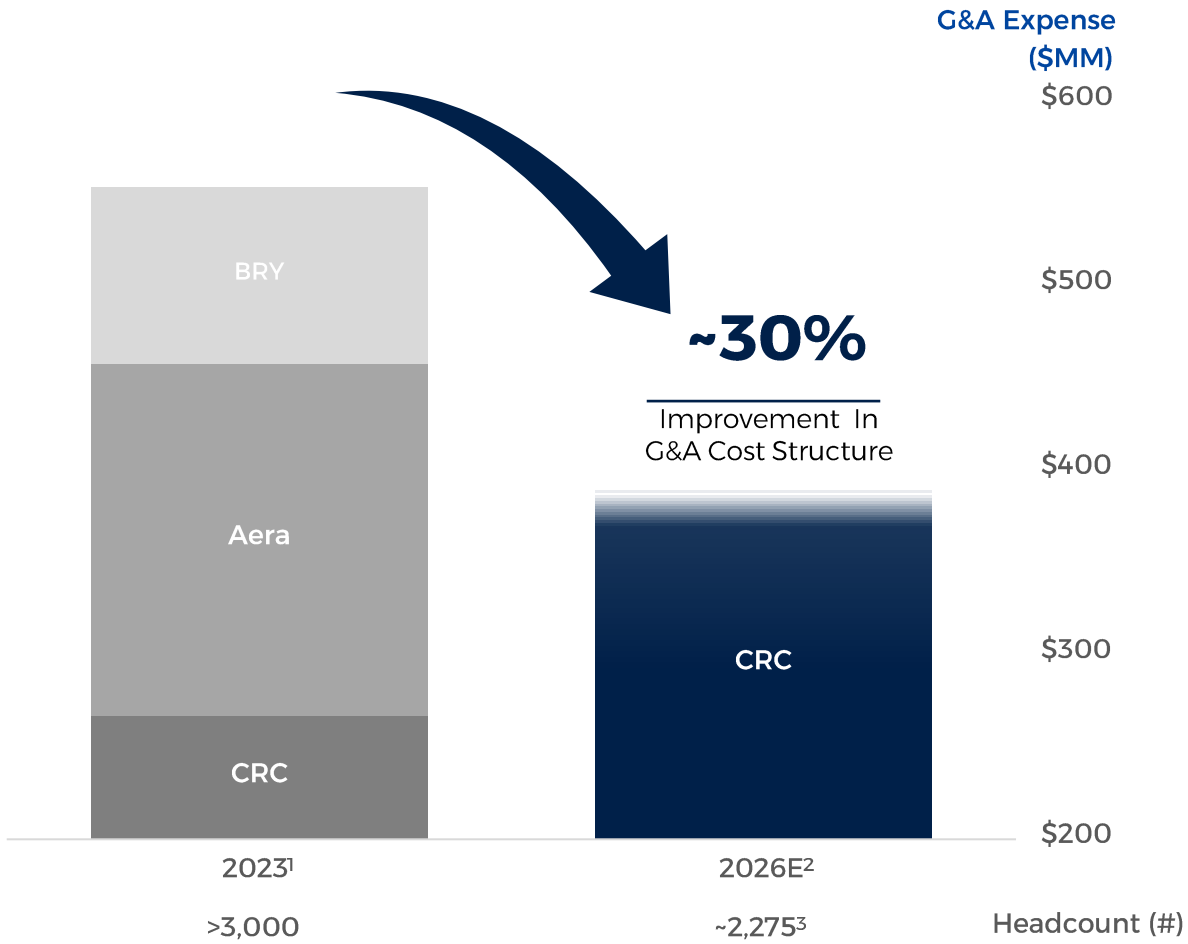


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Significant Improvement Since 2023

Reduced Operating Costs and G&A Expense by >$740MM Since 2023 Through Timely M&A Activity[1]

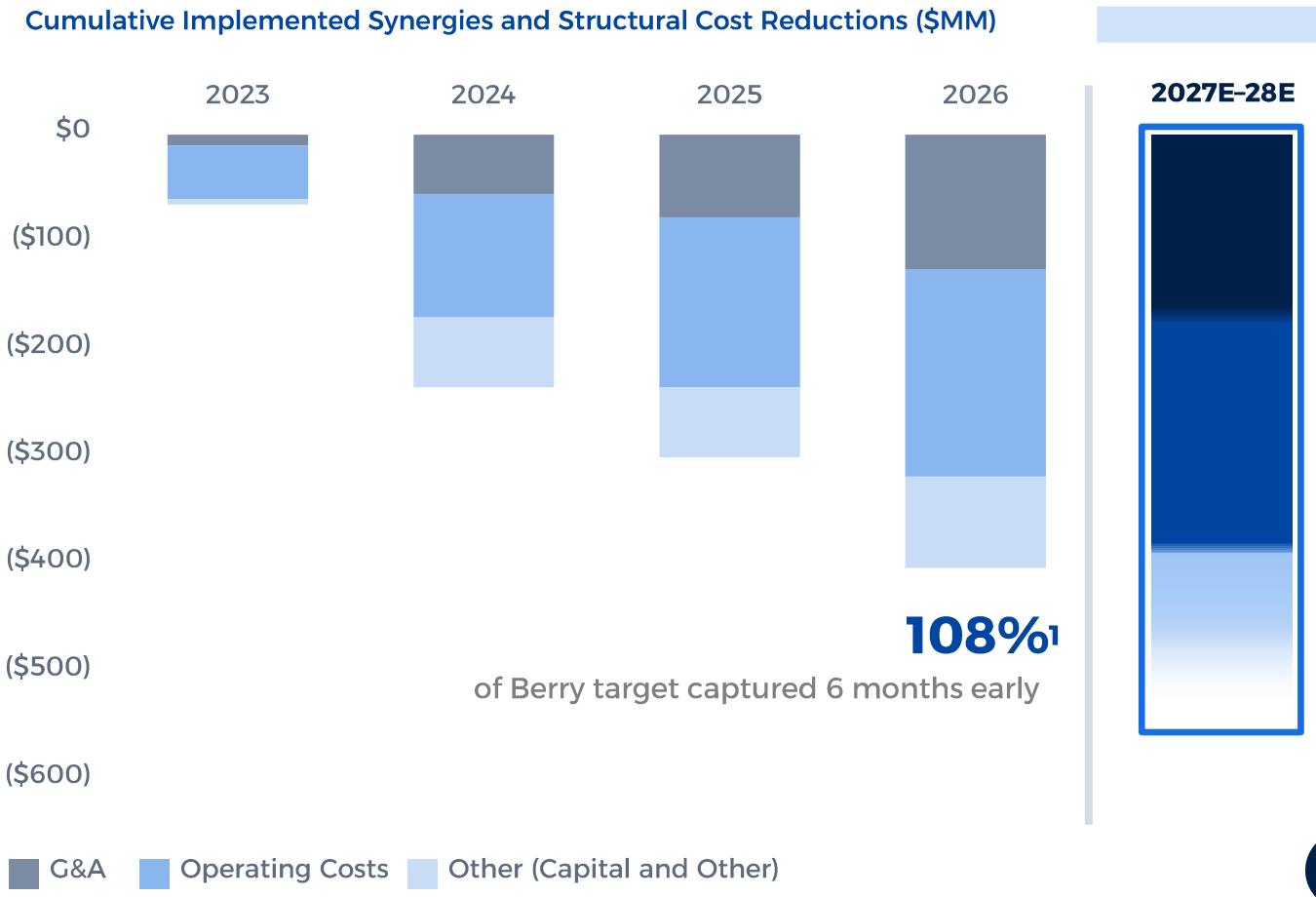




See slide 43 for "Assumptions, Estimates and Endnotes".

Unlocking the Value of Our Assets: The Next Chapter of CRC

From Integration Synergies to Organic Efficiencies



The Next Phase: Organic Cost Reductions

Lower controllable cost structure while maintaining safe, reliable operations and our ability to grow

Streamline Our Foundation
Standardize core systems and connect enterprise data

Simplify How We Work
Align how work gets done across the business, removing duplication remaining after the mergers

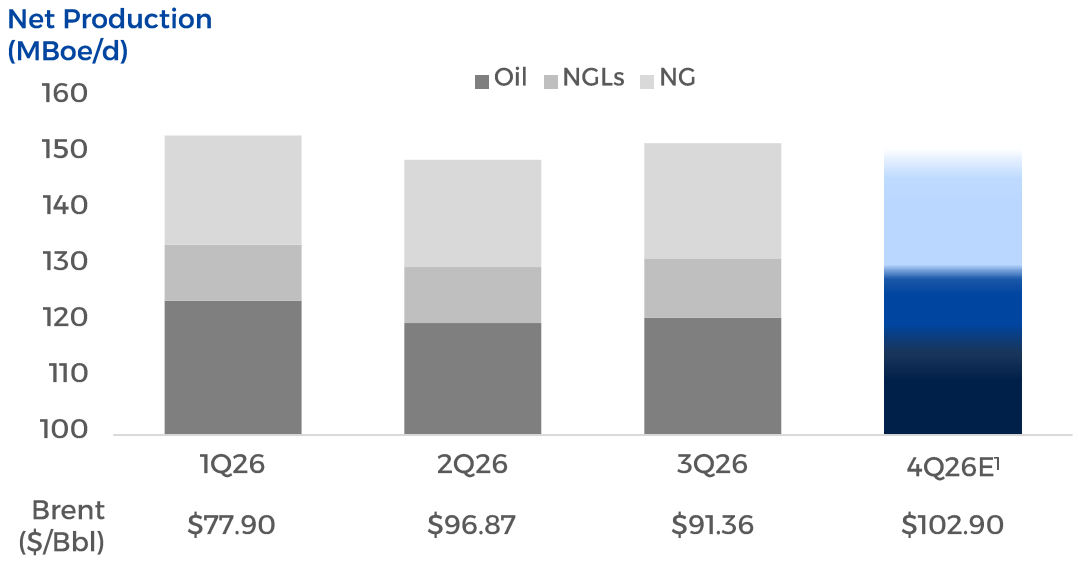
Apply AI and Digital Tools
Move faster, reduce manual work, and improve productivity

Cost reduction targets to be shared with our 2027 plan

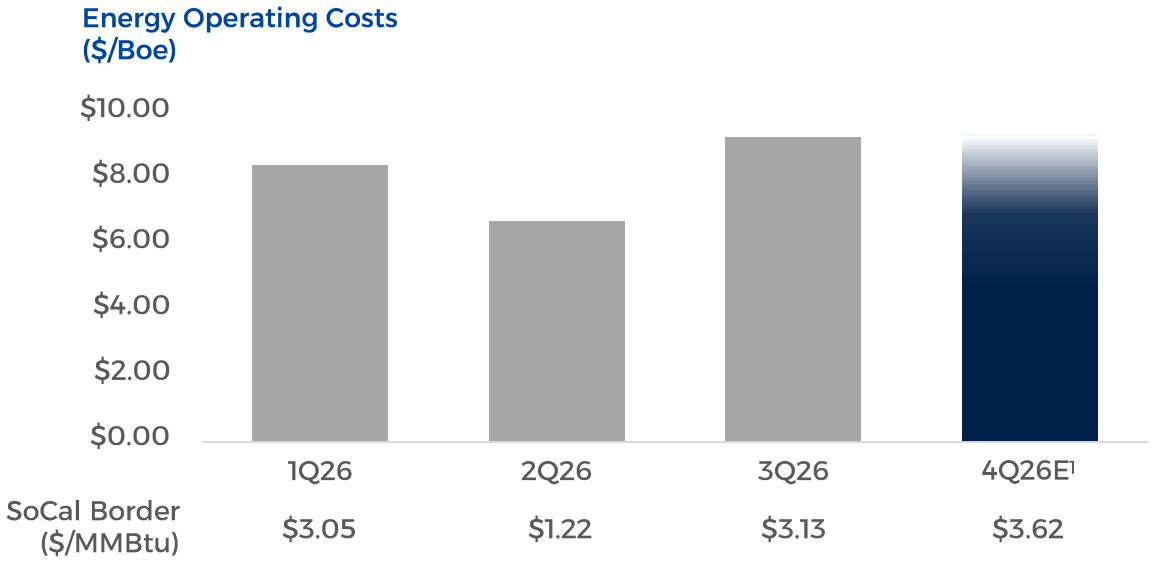
M&A Driven (2023–26) → **Organically Driven (2027–28)**

See slide 43 for "Assumptions, Estimates and Endnotes".

Strong Production Performance



Energy Costs Dependent on Fuel Prices



See slide 43 for "Assumptions, Estimates and Endnotes".

3Q26 Commentary

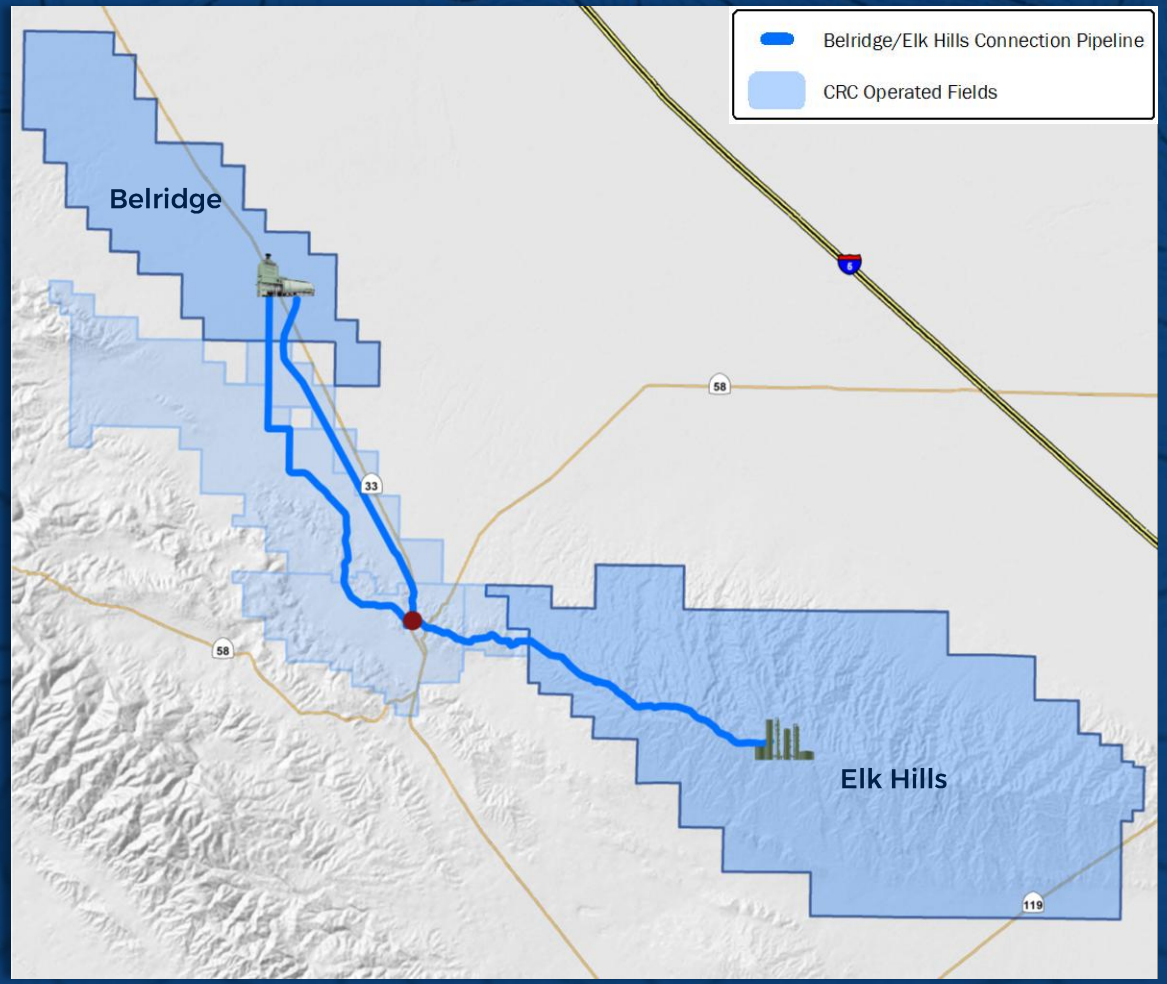
- **Net oil production** rose sequentially by ~1% to 121 MBo/d, primarily related to sale of crude oil inventory, and drilling and workover activity
- First CCS project enabled **stronger than previously anticipated NGL yields** and added ~1 MBoe/d in 3Q26[2]
- **Stronger electricity prices** drove higher EHPP utilization and higher natural gas sales
- **Uinta net production** contributed ~4 MBoe/d to 3Q26 results

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- **Higher-than-anticipated natural gas prices** drove an increase in energy operating costs for internal field operations
- **All-time high diesel cracks** led to high energy operating costs for drilling rig operations
- **Disciplined hedge strategy** mitigates fuel energy volatility with ~58% of 4Q26E natural gas consumption at an average price of $4.23/MMBtu; ~58% of 2027E natural gas consumption hedged at an average price of $3.98/MMBtu[3]

Benefits of Our Integrated Strategy in Action

Connection Between Belridge and Elk Hills Fields Supports Natural Gas Optimization

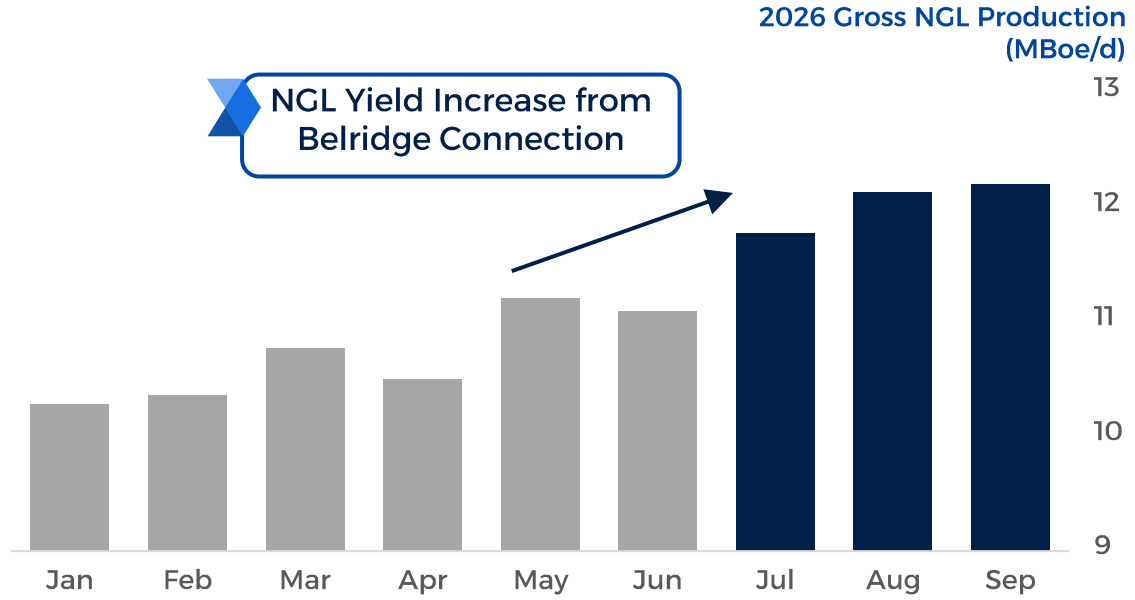


See slide 43 for "Assumptions, Estimates and Endnotes".

Carbon Capture Drives Incremental NGL Yields[1]

~6MMcf/d	~1MBoe/d	~$20MM[2]
Incremental Net Gas Production	Increase in Net NGLs Production	Est. Annual Revenue Benefit

- Carbon capture equipment from first CCS project cleans inlet gas to CRC's Elk Hills cryogenic gas plant, supporting incremental gas processing capacity and subsequently increased NGL yields
- Connection from Belridge production field to Elk Hills cryogenic gas plant supplies additional natural gas for processing
- Established infrastructure to support natural gas development and future infrastructure integration opportunities in the area

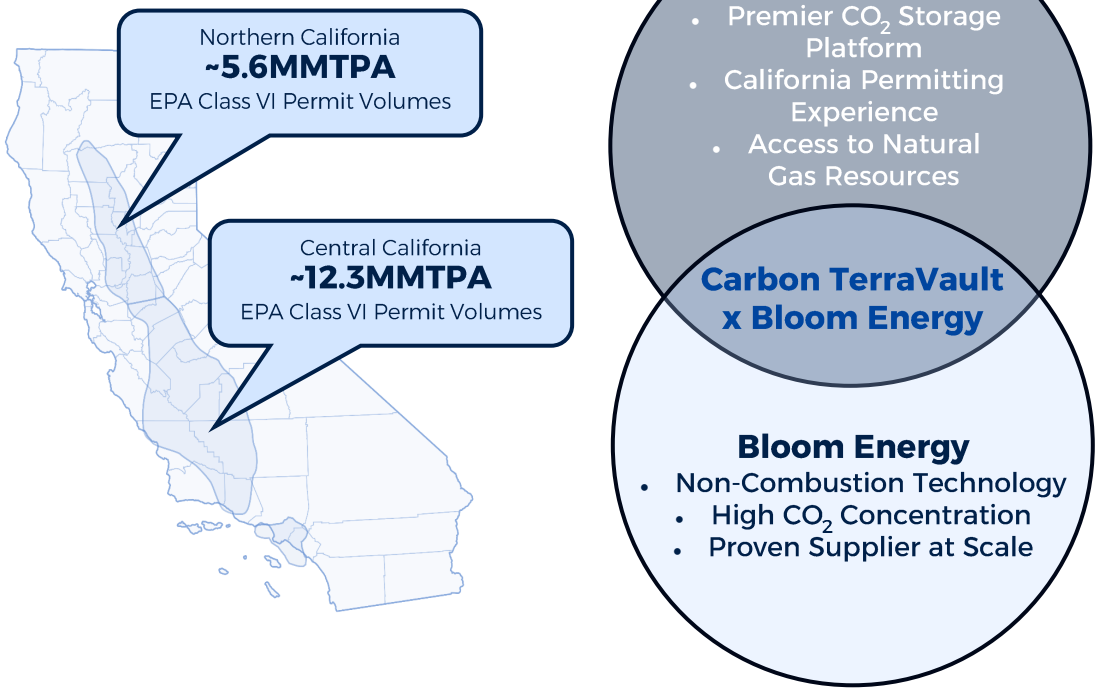


Bloom MOU[1] to Advance Clean Power Solutions in California

CARBON TERRAVAULT x Bloom energy

Developing Potential	Power Generation of	Up to
FTM & BTM	**1GW**	**3MMTPA**
Clean Power Solutions in CA	or More	of CO_2 Emissions

CTV EPA Class VI Permit Volumes[2] (MMTPA)



See slide 43 for "Assumptions, Estimates and Endnotes".

Collaboration with Leading Clean Power Producer

CTV and Bloom Energy to jointly evaluate and target the potential development of solid-oxide fuel cell power generation paired with CCS across California

- Identifying and developing new commercial pathways with potential power offtake customers
- Initially contemplating FTM and BTM power opportunities:
  1. **FTM Clean Energy Projects** – targeting multiple projects with potential connection to CTV's vast California storage portfolio and utility offtake
  2. **BTM Clean Energy Opportunities** – additional contemplated projects across CRC's Central Valley footprint, designed for industries seeking on-site, clean and reliable power

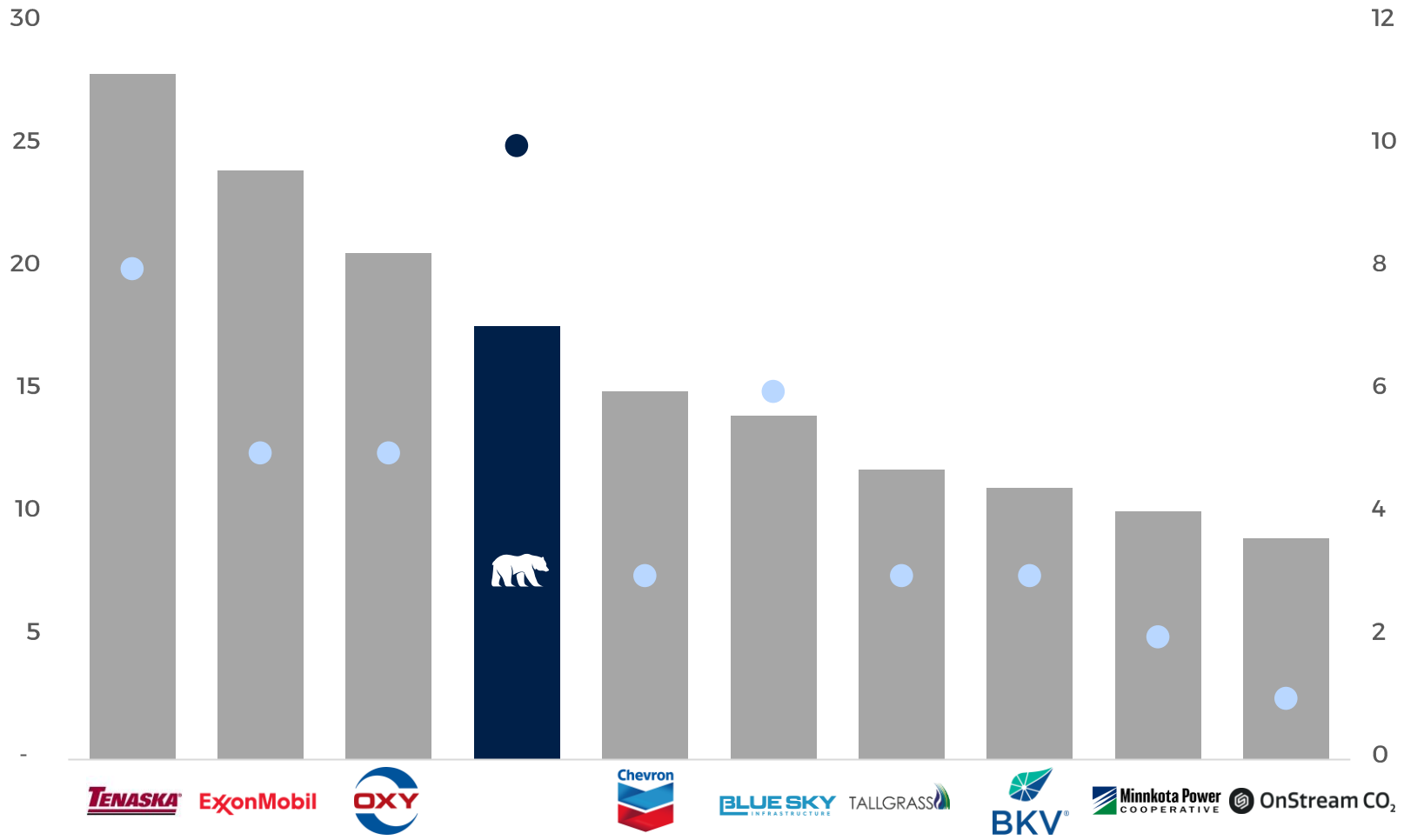
MOU[1] leverages the combined strengths of both companies to develop baseload clean power solutions in California

- **CRC's proven track record of developing projects** from permitting to execution
- **CTV's leading CCS storage platform** in California
- **Bloom's clean, non-combustion fuel cells** with a **high-concentration CO_2 stream** improving the efficiency of CCS

CTV: 4th Largest Carbon Management Platform in the U.S.[1]

Total Reservoir Injection Capacity Submitted for Permits (MMTPA)

Total CO_2 Storage Projects (#)



See slide 43 for "Assumptions, Estimates and Endnotes".

California's Leading CO_2 Storage Portfolio

36%

EPA Class VI Wells (US)[2]

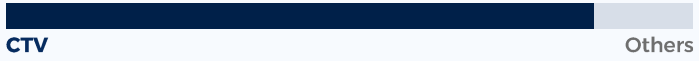
Largest individual share of wells under EPA lead agency review



88%

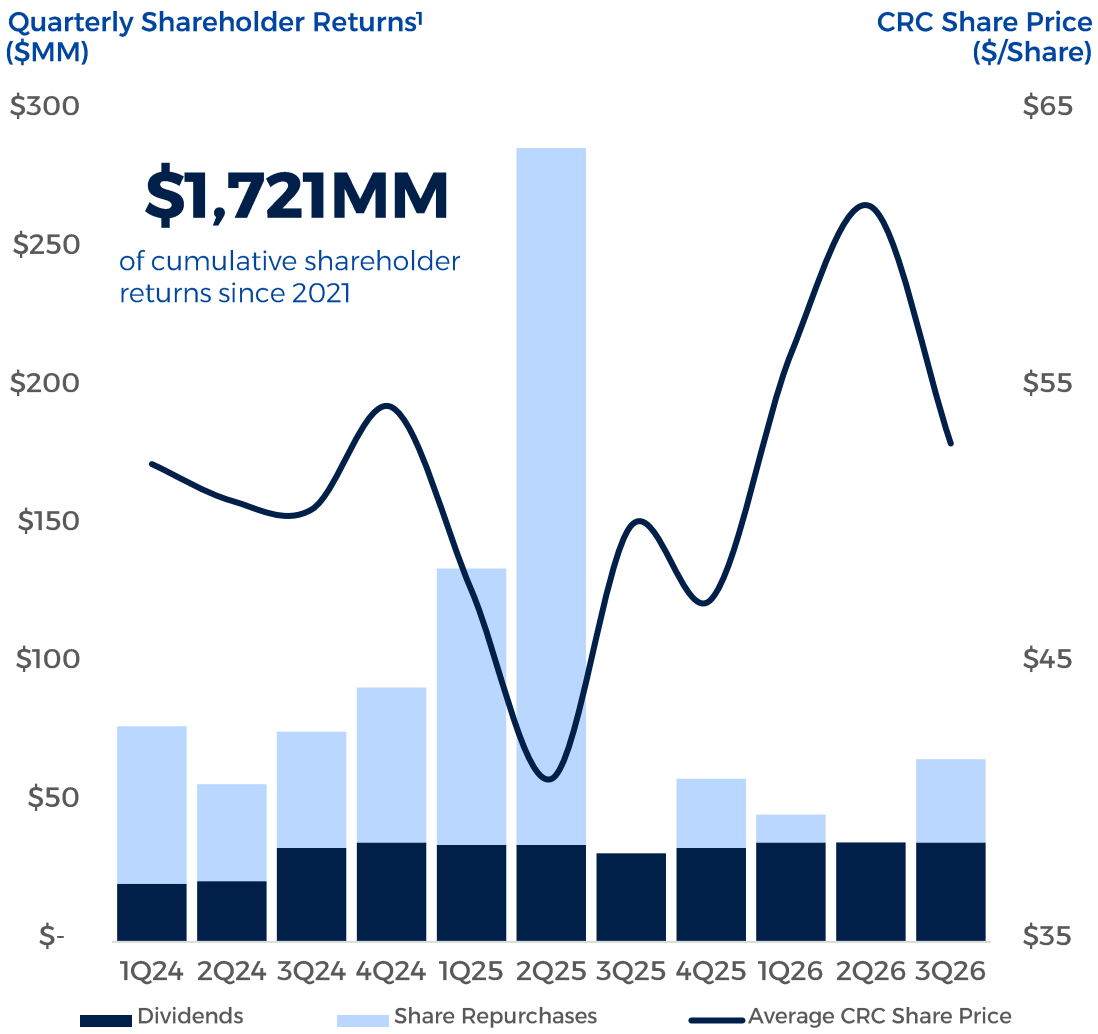
California Class VI Wells[2]

Dominant share of the emerging California CCS market



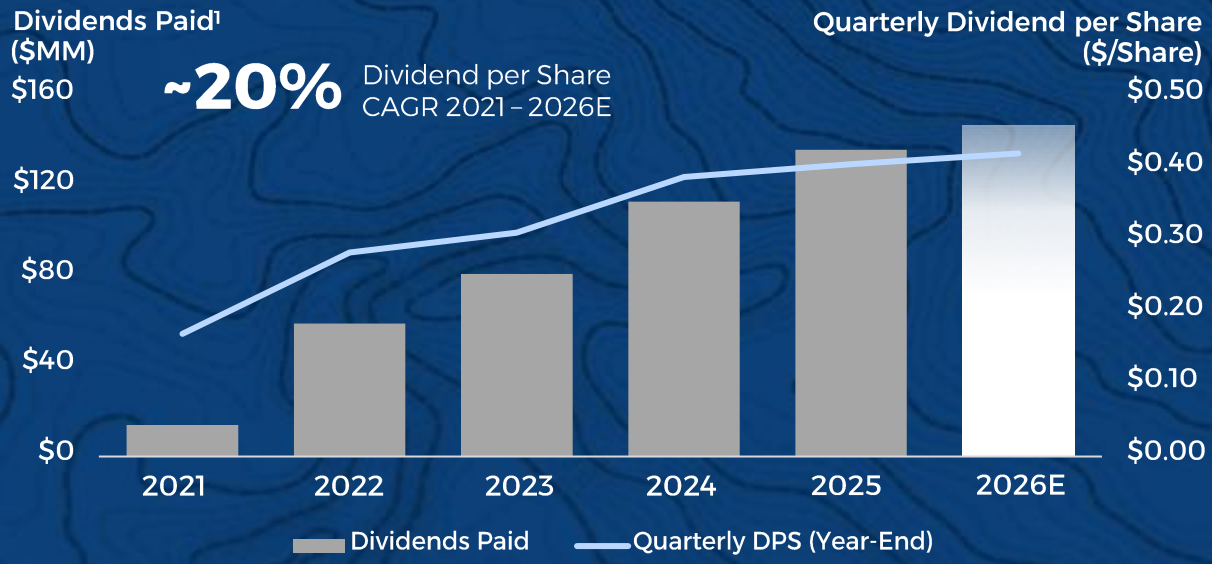
- Submitted a new EPA Class VI permit (CTV VIII) for ~57MMT[2] of storage
- Anticipating the receipt of one or more additional draft EPA Class VI permits by year-end 2026[2]

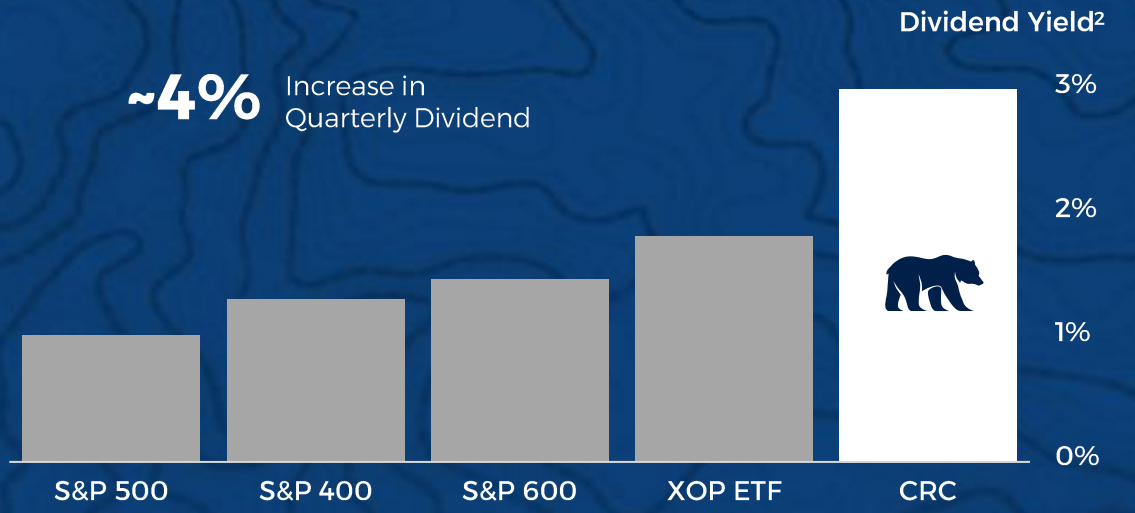
Opportunistic Share Repurchases Create Value



See slide 43 for "Assumptions, Estimates and Endnotes".

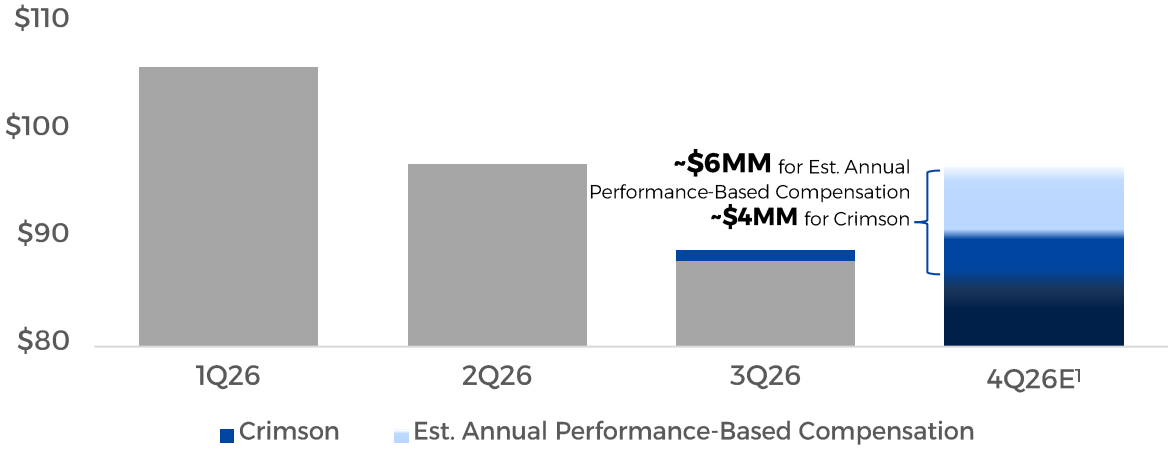
Commitment to Long-Term Dividend Growth



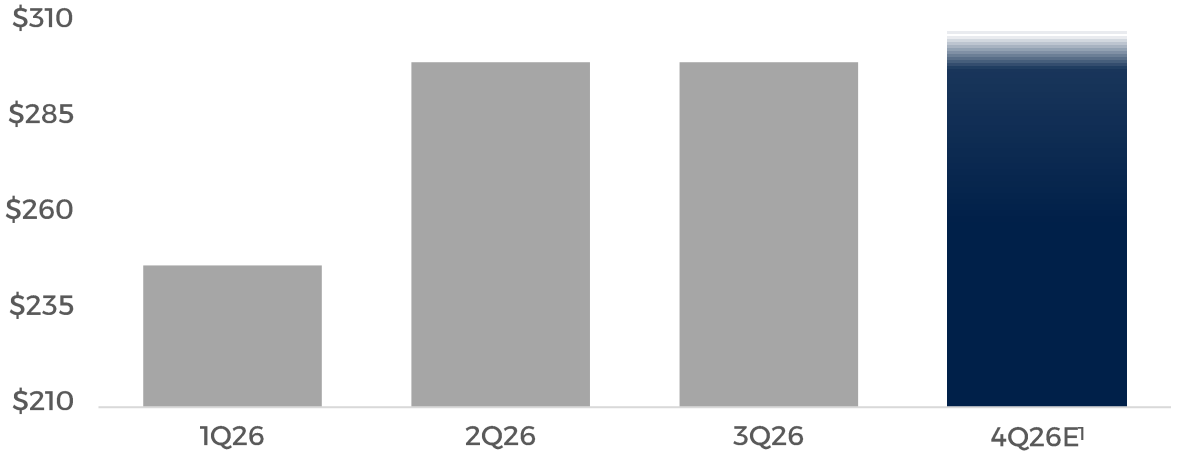


Improving the Core Cost Structure to Grow Long-Term Cash Flow

G&A Expense ($MM)



Operating Cash Flow Before WC Changes* ($MM)



Note: "Before WC Changes" means "Before Net Changes in Operating Assets and Liabilities".
See slide 44 for "Assumptions, Estimates and Endnotes".

3Q26 Results

Commodity	3Q26A
Oil Realizations (% of Brent)	~91%
NGL Realizations (% of Brent)	~53%
Natural Gas Realizations (% of NYMEX)	~119%
Operational and Financial	
Net Production (MBoe/d)	152
Net Oil Production (MBo/d)	121
Operating Costs ($MM)	$386
G&A Expenses ($MM)	$89
Adj. G&A Expenses* ($MM)	$79
Taxes Other Than on Income ($MM)	$81
Transportation Costs ($MM)	$31
Other Operating Expenses Net of Other Revenue*, 2	$35
Total Capital ($MM)	$158
Adj. EBITDAX* ($MM)	$341
Operating Cash Flow Before WC Changes*	$300
Free Cash Flow Before WC Changes*	$142
Other Items	
Margin from Purchased Commodities*, 3	$15
Electricity Revenue Net of Electricity Generation Expenses*, 4	$35
Total Return of Cash to Shareholders[5] ($MM)	
Share Repurchases ($MM)	$30
Dividends Paid ($MM)	$36
Total Shareholder Returns ($MM)	$66

Strong Balance Sheet and Financial Flexibility

Recent Highlights

- S&P upgraded corporate rating to BB-
- Borrowing base reaffirmed at $1.5B in October 2026
- Extended maturity of revolving credit facility to March 2030

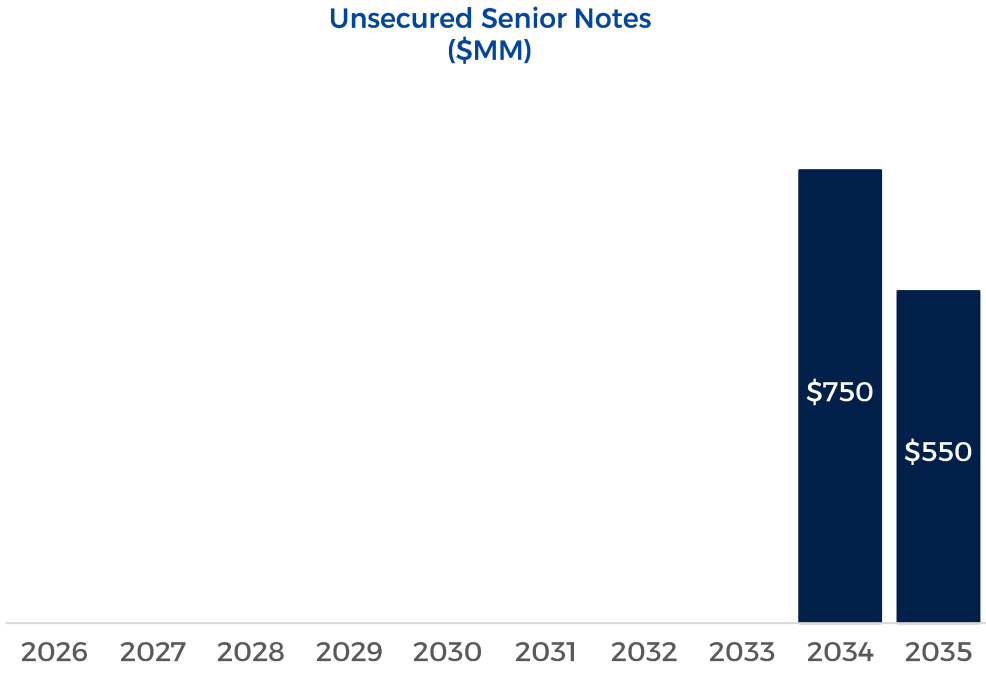
Liquidity Snapshot

Net Debt* as of September 30, 2026		**($MM)**
Revolving Credit Facility (RCF)	$	–
7.000% 2034 Senior Notes		750
7.250% 2035 Senior Notes		550
Face Value of Total Debt	**$**	**1,300**
Less: Available Cash & Cash Equivalents[1]		(35)
Net Debt*	**$**	**1,265**
Liquidity*, [2]	**$**	**1,315**
3Q26 Net Leverage*, [3]		**1.0x**
3Q26 Interest Coverage*, [4]		**11.0x**

See slide 44 for "Assumptions, Estimates and Endnotes".

Long-Dated Debt Maturities Support Strategic Growth

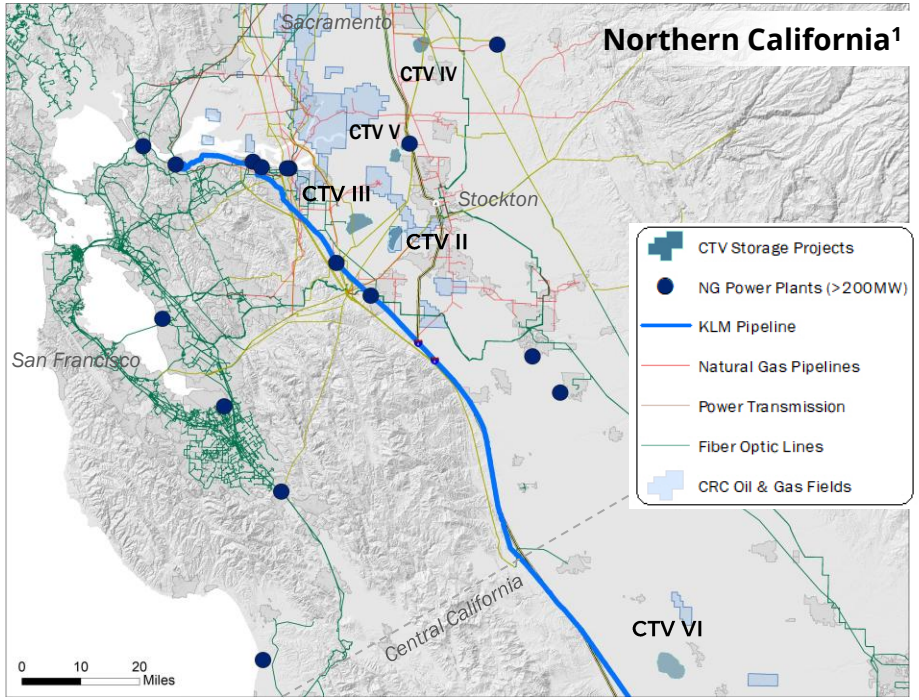
No Debt Maturities Until 2034

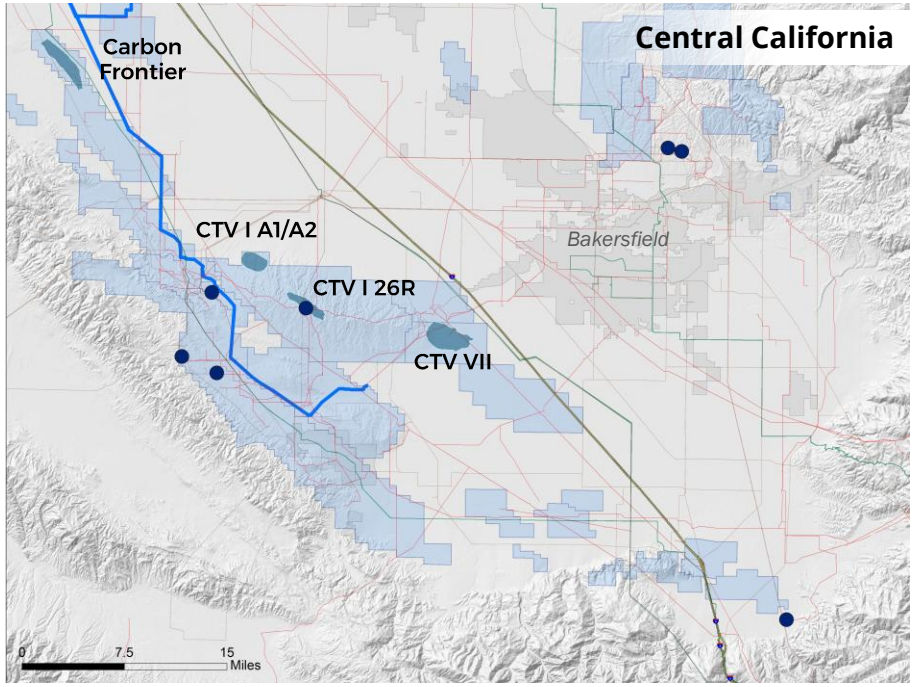




Appendix

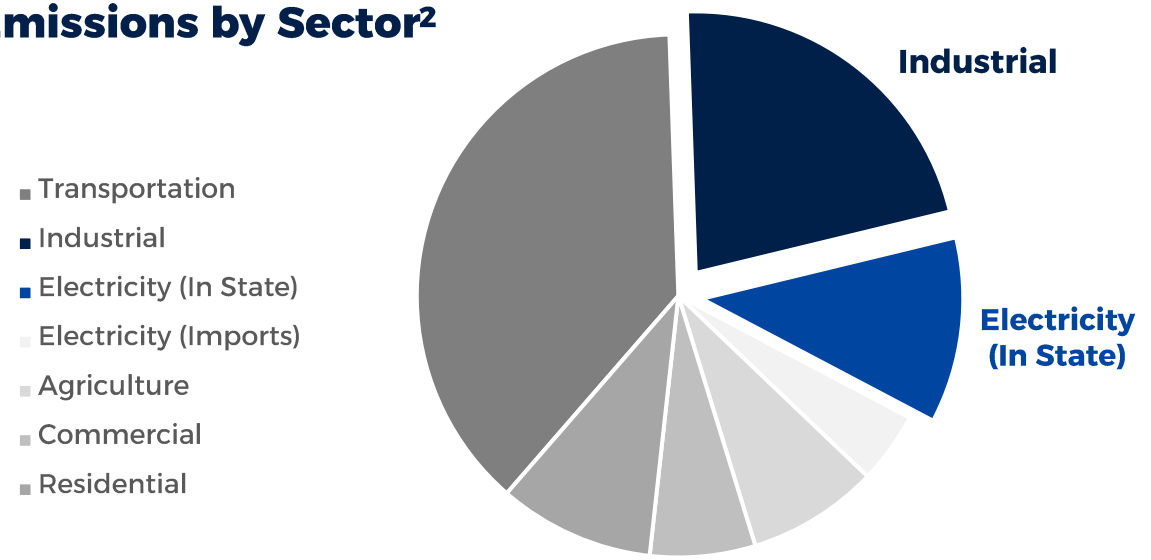
Well Positioned to Decarbonize California's Largest Industries





- 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[2]

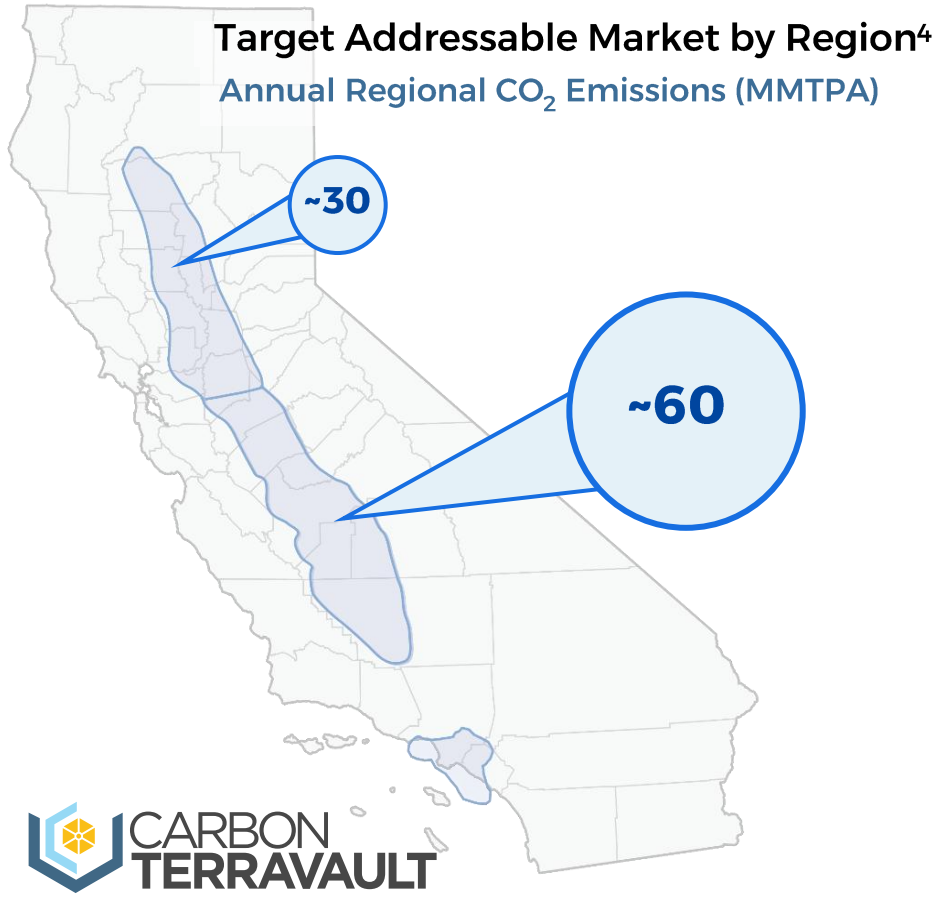


See slide 44 for "Assumptions, Estimates and Endnotes".

California's Premier Carbon Management Provider

- Anticipating the receipt of one or more Class VI draft permits for additional reservoirs in 2026[1]

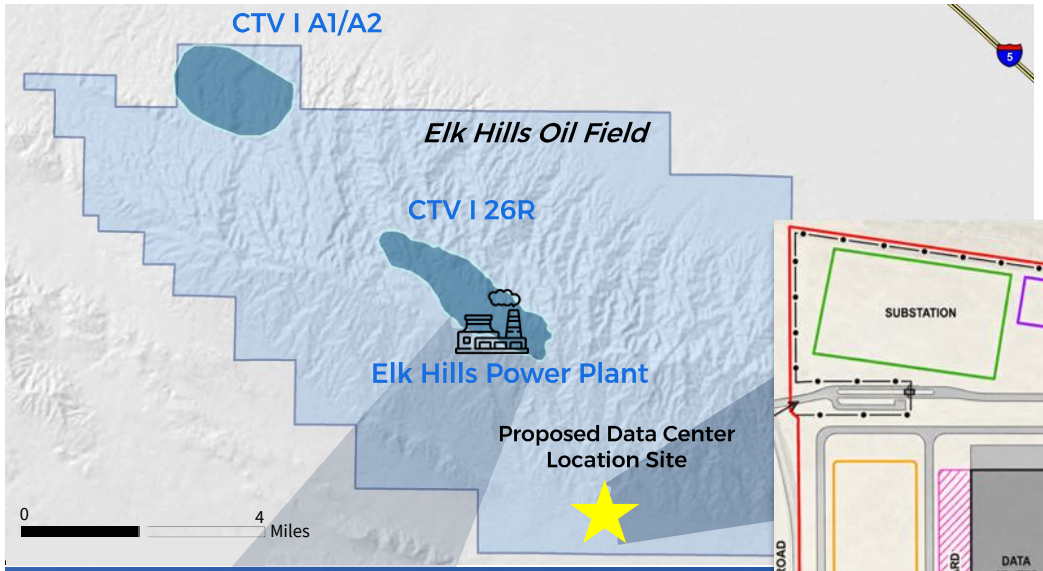
Vault / Reservoir	Targeted EPA Class VI Permit Decision[1]		Est. Annual Injection Rate[1] (MMTPA)			Permit Volumes[1] (MMT)
	Draft Permit	Final Permit	EPA Class VI Permit	20 Years	40 Years	
CTV I 26R	Permit Received[2]		~1.5[3]	~1.9	~1.0	~38
CTV I A1-A2	2026	2026	~0.8	~0.4	~0.2	~8
Carbon Frontier	2026	2027	~3.3	~1.6	~0.8	~32
CTV VI	2027	2027	~3.4	~5.1	~2.5	~102
CTV VII	-	-	~1.4	~1.4	~0.7	~27
CTV VIII[NEW]	-	-	~1.9	~2.9	~1.4	~57
Central California			~12.3	~13.3	~6.6	~264
CTV II	2027	2027	~1.0	~1.2	~0.6	~23
CTV III	2026	2027	~2.5	~3.6	~1.8	~71
CTV IV	2027	2027	~1.4	~1.7	~0.9	~34
CTV V	2027	2027	~0.7	~0.8	~0.4	~17
Northern California			~5.6	~7.3	~3.7	~145
Total - Combined			~17.9	~20.6	~10.3	~409



See slide 44 for "Assumptions, Estimates and Endnotes".

Golden Valley Technology Hub | Uniquely Positioned

Proposed "Premier" Data Center Campus





CRC's Elk Hills Power Plant
~550 MW



California's "Premier" Data Center Campus

PARTNERSHIP WITH BEACON DATA CENTERS
A LEADING NORTH AMERICAN CO-DEVELOPER

275MW | INTERCONNECT WITH PG&E | GROWTH OPPORTUNITY

GOLDEN VALLEY TECHNOLOGY HUB

- UNPARALLELED LAND POSITION
- EXISTING POWER PLANT
- SOCIALLY-RESPONSIBLE DEVELOPMENT
- STRONG PARTNER WITH EARLY DEVELOPMENT CAPITAL DEPLOYED

PROVEN PERMITTING TEAM

- HISTORICAL TRACK RECORD OF SUCCESS
- CONDITIONAL USE PERMIT SUBMITTED
- ENVIRONMENTAL IMPACT REPORT TO BE SUBMITTED IN 4Q26

TARGETED VALUE CAPTURE

- HYPERSCALER COMMITMENT – LOI
- CONTRACTED POWER – PPA
- RECEIPT OF PERMITS
- PROJECT FID
- PROJECT ONLINE

Note: See www.goldenvalleytechhub.com for additional information.

Golden Valley Technology Hub | Community Focused

The project is expected to provide the following community benefits:

Water

- Closed-loop cooling — lowest-use category of any data center design
- 600,000-gal initial fill (~30 residential pools); Expect ~6,000 gal/yr recharge (<1/3 pool/yr)

Power

- Powered directly by CRC-owned Elk Hills Power Plant | ~275 MW available power capacity
- Developer funds all project infrastructure; no rate impact or grid upgrades

Noise

- Sited on existing industrial land; nearest residence ~1 mile away
- Noise profile comparable to a mid-sized office building

Jobs

- ~1,500 peak construction jobs; up to 250 permanent operating roles
- First CA O&G company with a statewide Project Labor Agreement

Tax Revenue

- Recurring property tax on real & data-center personal property
- CRC was the #1 taxpayer in Kern County in 2025[1]

Note: See www.goldenvalleytechhub.com for additional information. CRC internal estimates. See slide 44 for "Assumptions, Estimates and Endnotes".

Power-to-CCS Expansion

AI inference is driving rising demand for reliable in-state power

Grid capacity could expand through PG&E data center interconnects and CPUC procurement

Regulatory momentum supports Power-to-CCS optionality

Current Market Dynamics

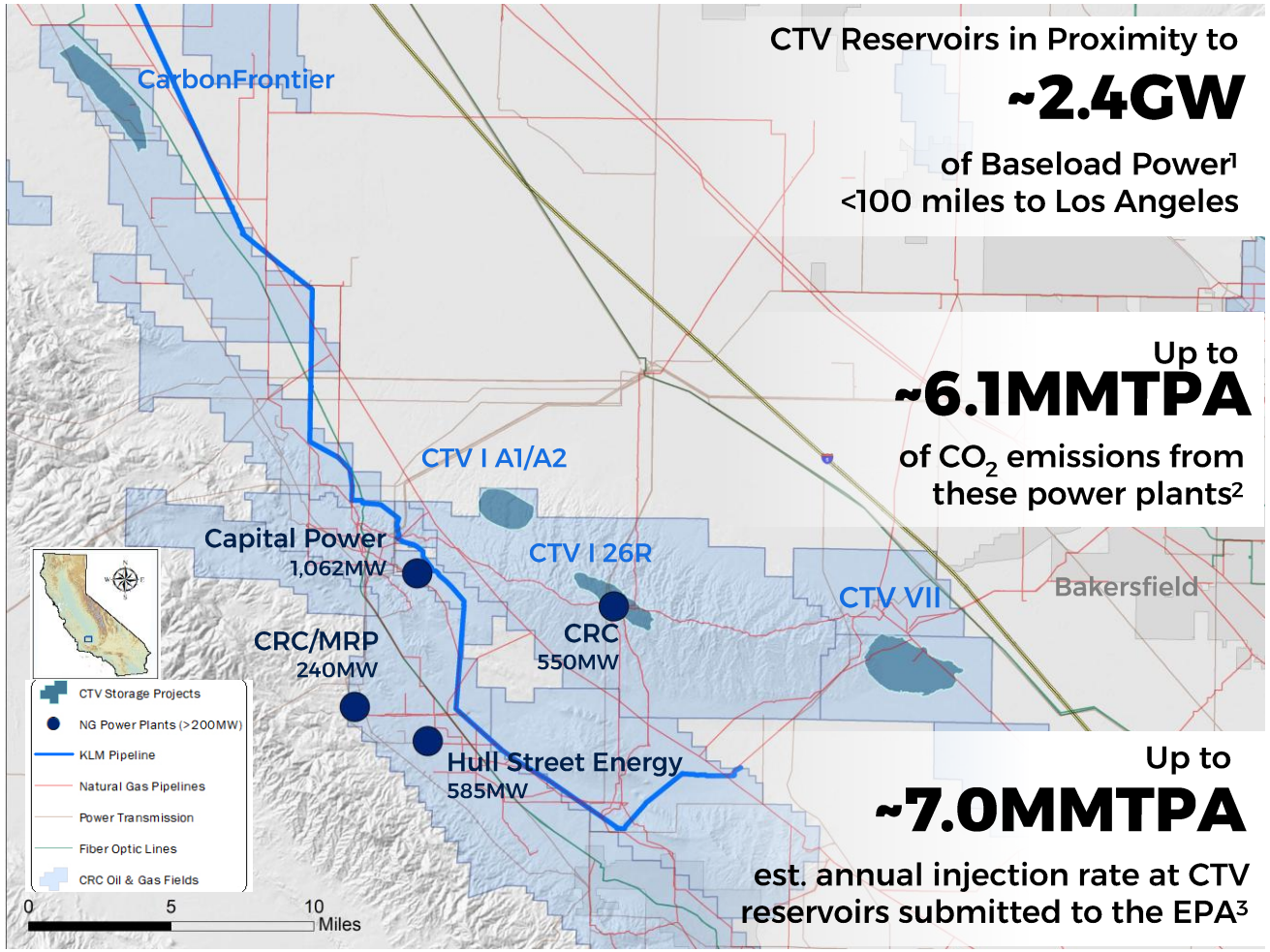
Opportunity	Customers	Clean Premium
1 FTM Utility Sale	Utilities	✓
2 FTM Sale	Existing Data Centers, Industrials	✓
3 BTM Industry Sale	New Data Centers, Industrials	✓

See slide 44 for "Assumptions, Estimates and Endnotes".

Kern County CCS Opportunity

- Natural gas pipeline connectivity
- Power interconnect
- Water availability and supply
- Proximity to major fiber networks
- Access to premier CO_2 storage reservoirs
- Possible CO_2 pipeline connectivity

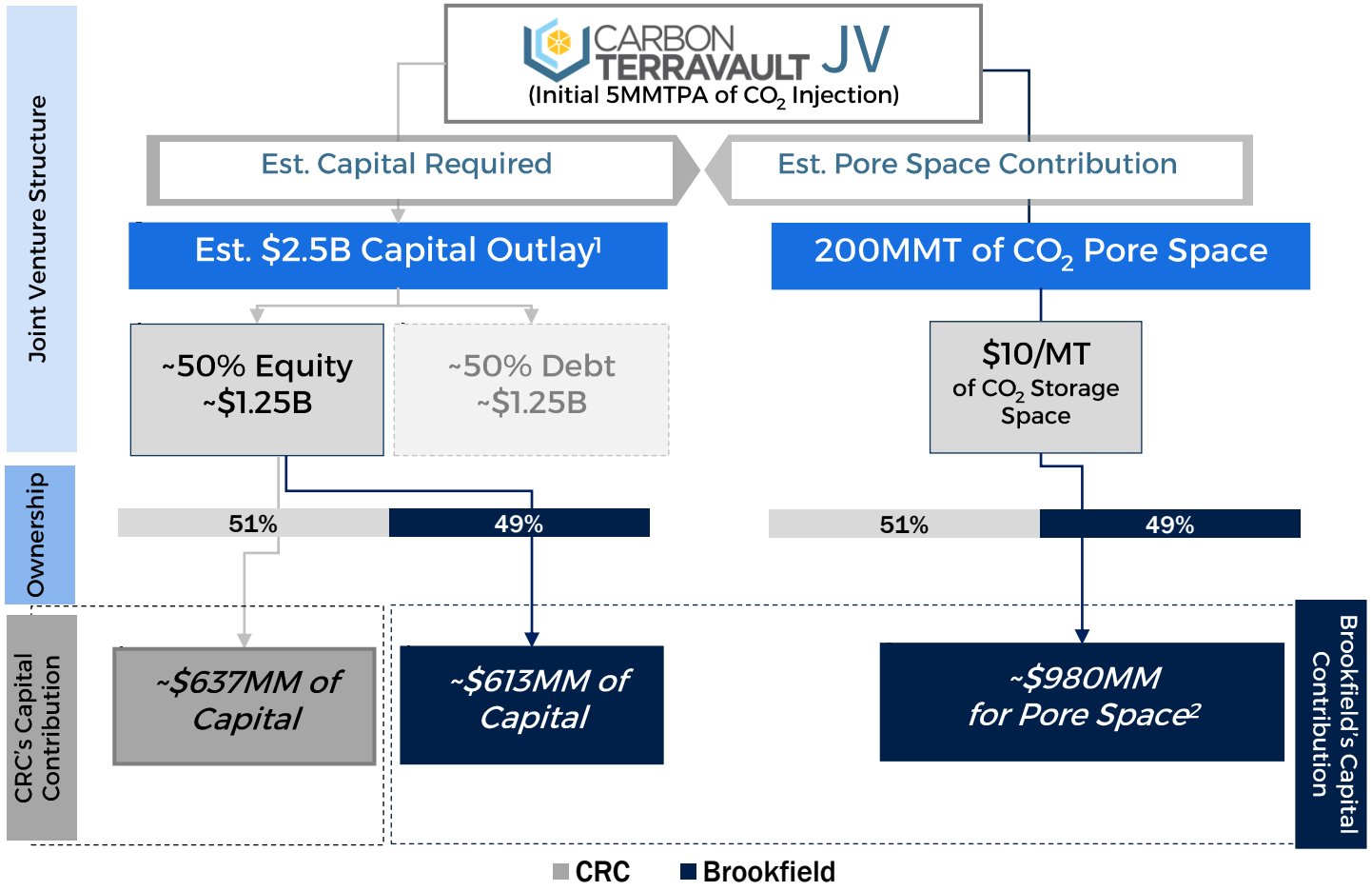
Powered Land



Strategic Carbon Management Partnership

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

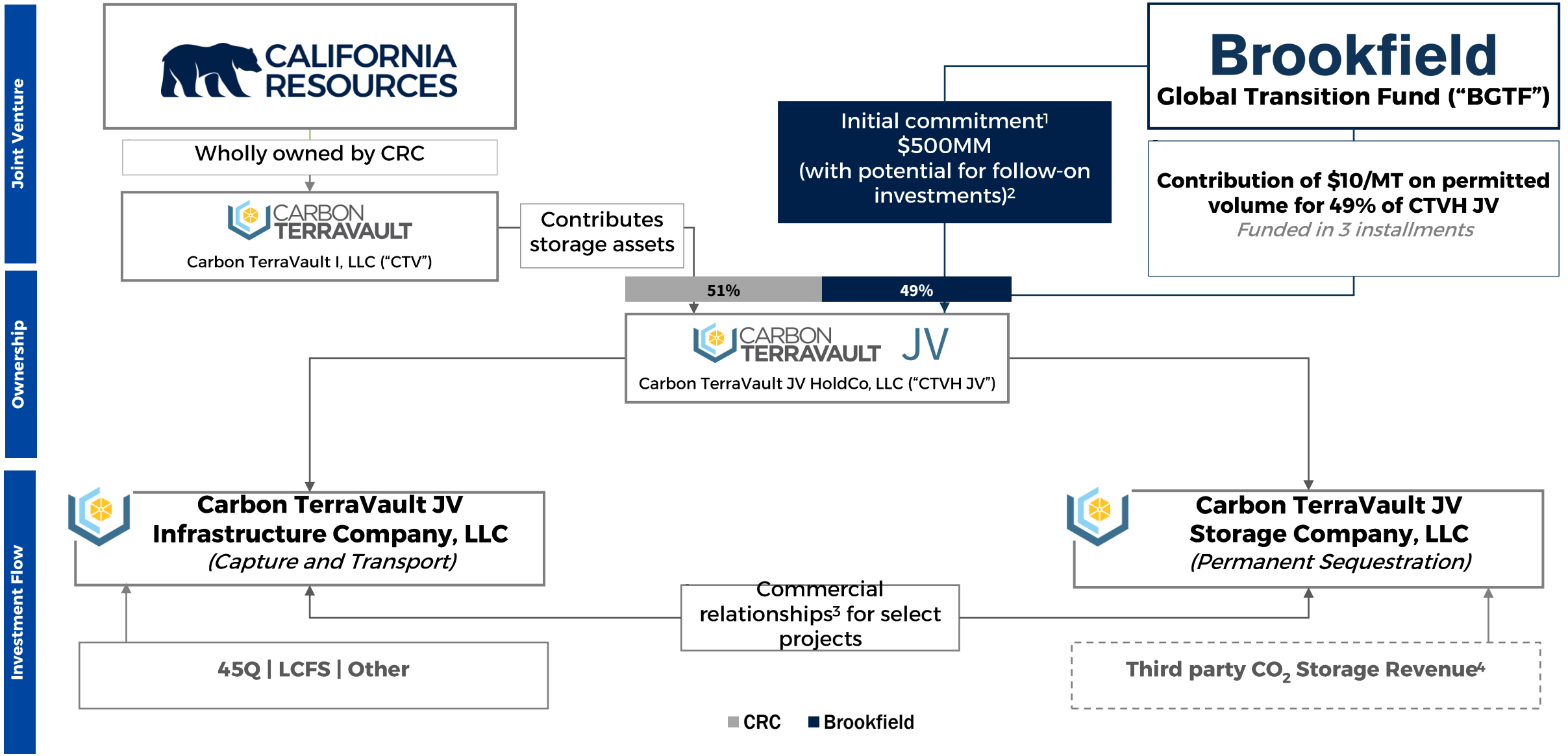
- Capitalizes first 5MMTPA of projects and provides potential funding for CRC's development of 200MMT of CO_2 storage
- CRC's equity commitments for the first 5MMTPA are more than 2x covered by Brookfield's initial commitment for projects jointly approved through the CTV JV
- Allows CRC to increase flexibility 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 45 for "Assumptions, Estimates and Endnotes".

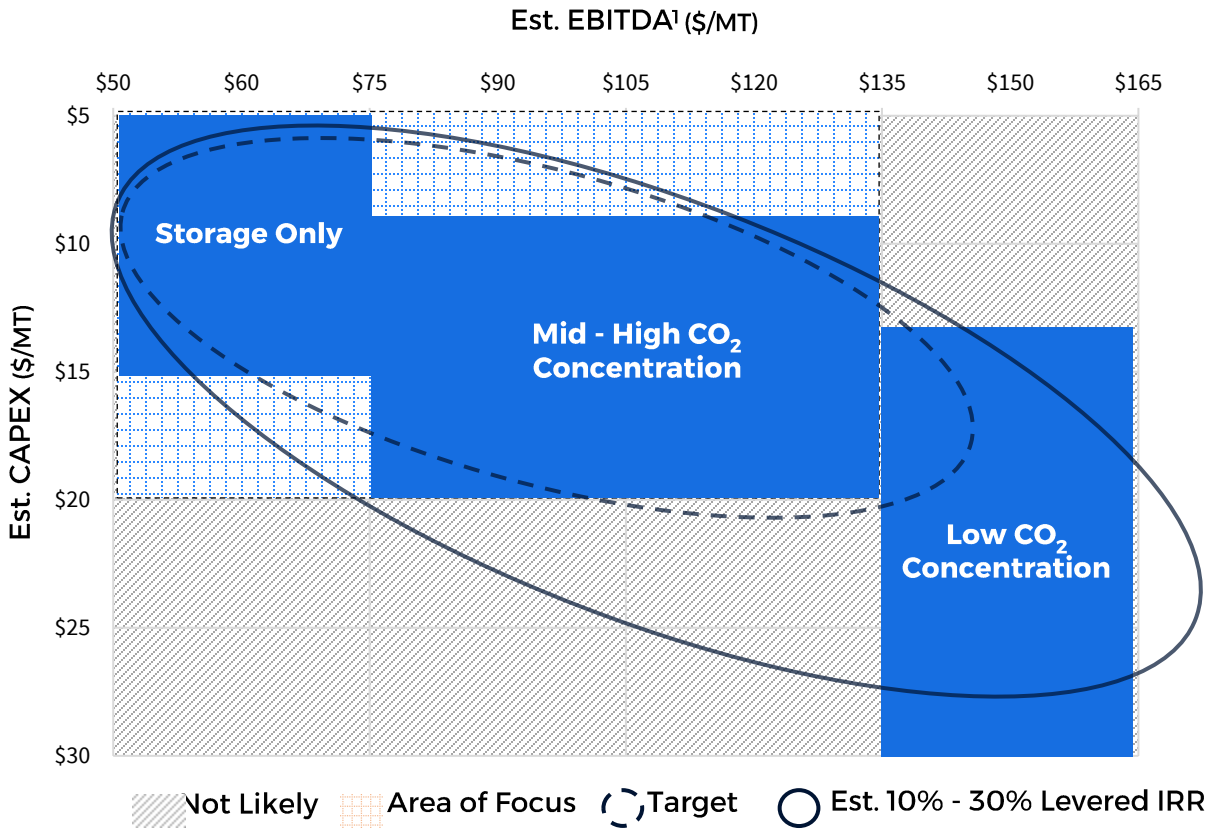
Carbon TerraVault Joint Venture Details



Note: Diagram for illustrative purposes only. See slide 45 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 45 for "Assumptions, Estimates and Endnotes".

De-Risked New-Drill Permitting Environment

Faster Permitting Shifts Growth Constraint to Execution

Key Commentary

- SB237 deemed Kern EIR sufficient for up to 2,000 new-drill county-wide permits per year until Jan. 1, 2036
- Significant increases in speed of execution: notice-of-intent (NOI) to permit approval of ~17 days and permit approval to spud of ~95 days
- Decreased reliance on sidetracks and workovers as capital focus turns to new drills
- SB237 requires additional regulatory approvals to reactivate idled oil and gas pipeline infrastructure (>5 years offline) increasing the value of existing, in-service pipelines

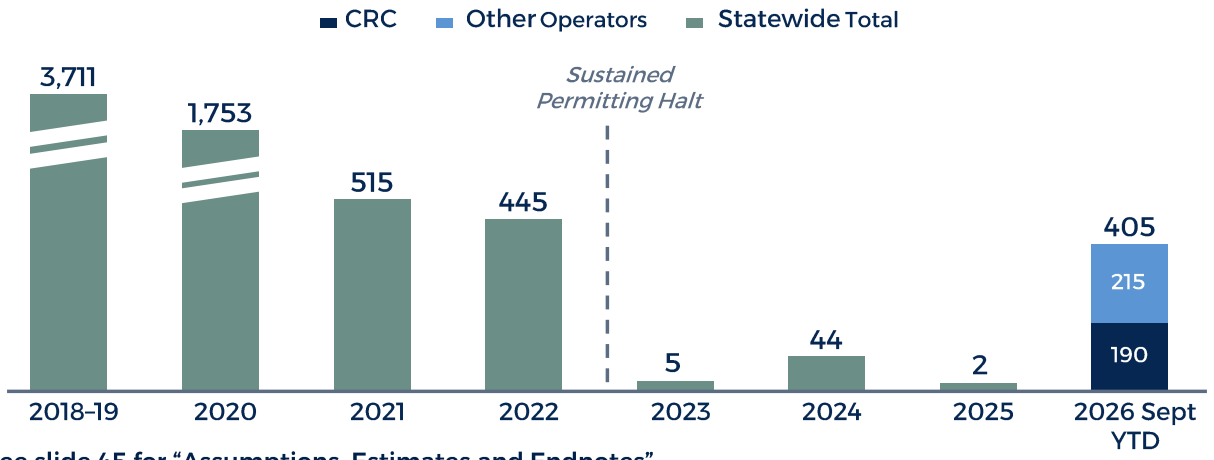
CRC Kern County New-Drills – Before and After SB237[1]

	2025	2026 September YTD
New-Drill Permits	–	189
Approval Path	Stalled	~17 days
Avg. CA Rigs	~2	~4–5
Activity	Sidetracks + Workovers	New-Drills + Previous Activity

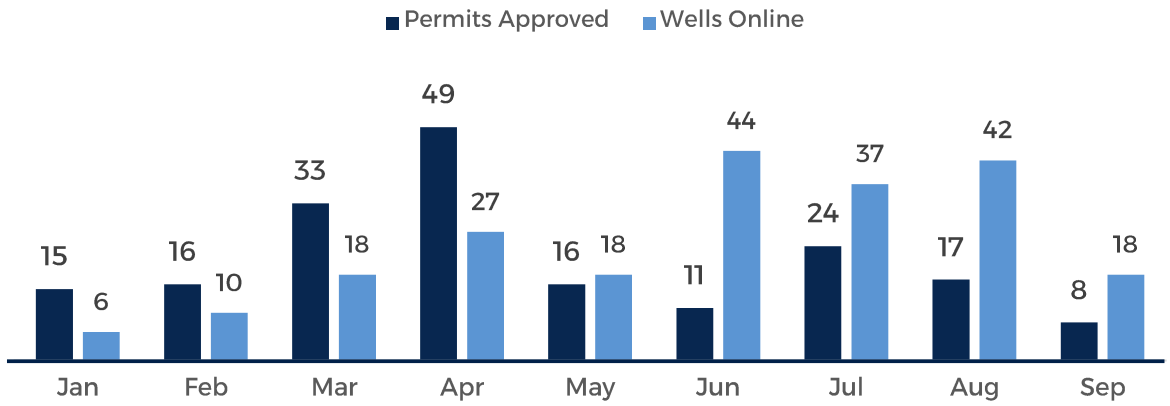
CRC Well Permit Timeline

NOI Filed	Permit Approved	Well Spud	First Production
Day 0	~17 days	~95 days	~15 days

Annual Statewide New-Drill Permits Approved - 2026 CRC vs Others[1]



CRC SB237 Approvals vs Spuds by Month, 2026[2]



See slide 45 for "Assumptions, Estimates and Endnotes".

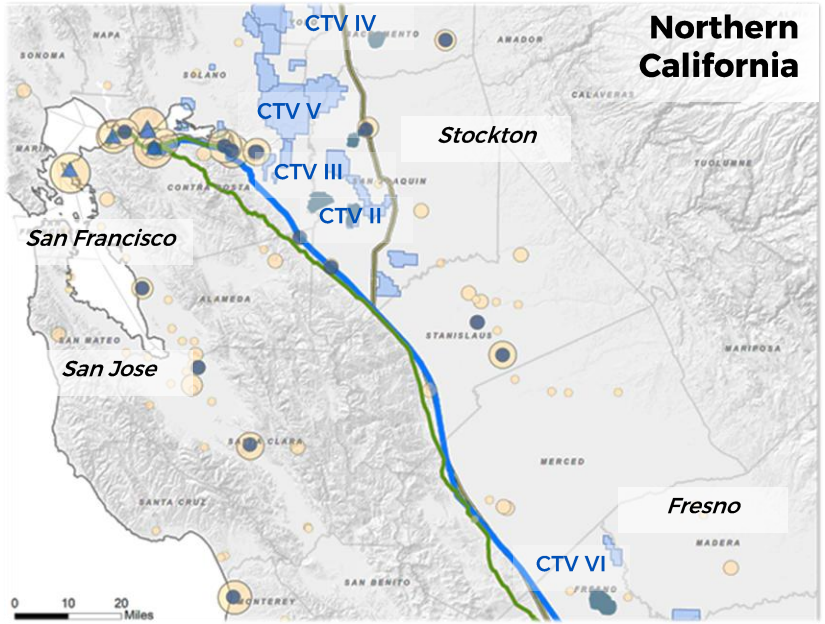
Midstream Integration Enhances Commodity Marketing Advantage

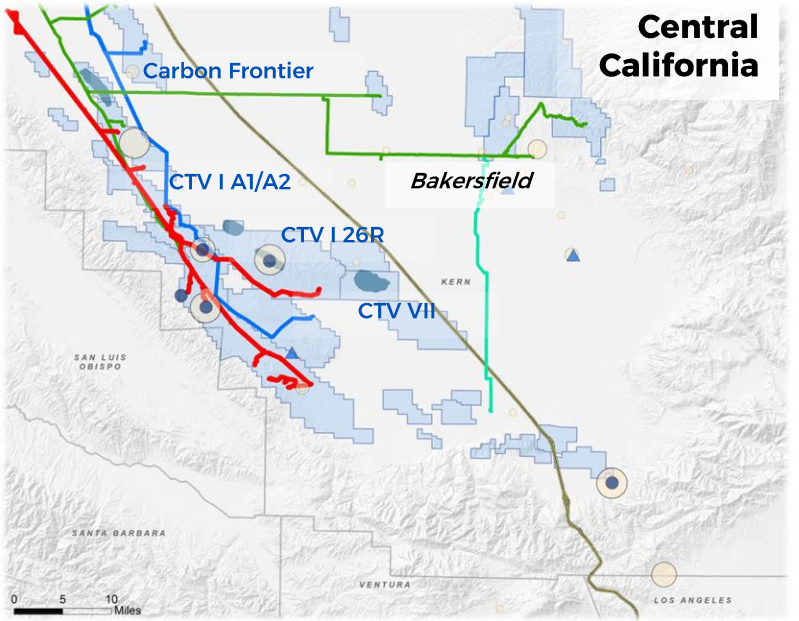
Crimson Acquisition Added Critical Northbound Access Lines

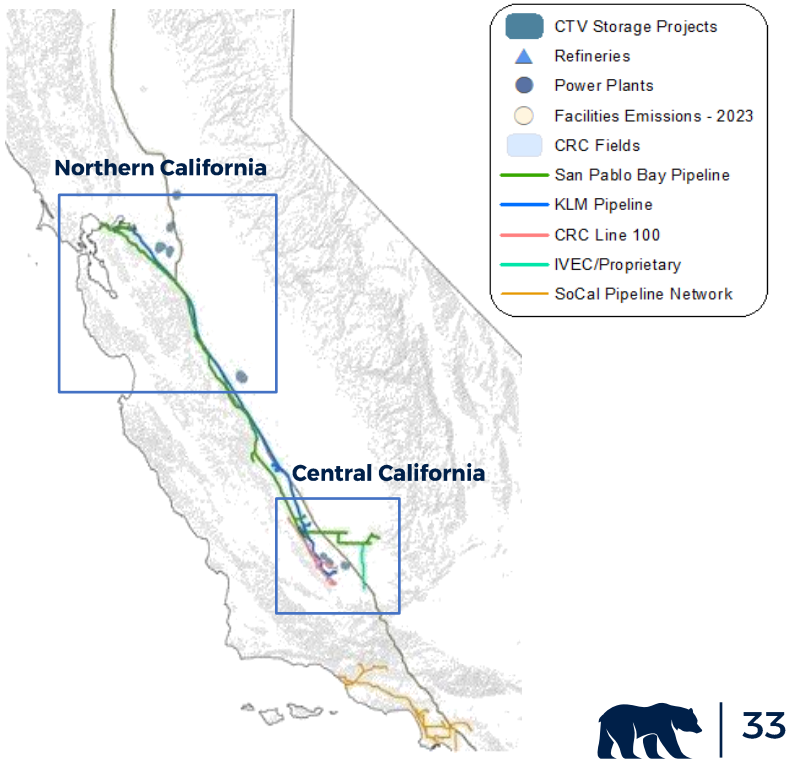
- ~2,000-mile pipe system and storage to link Central California's production to the highest-value markets and other growth opportunities
- Includes SoCal Pipeline Network, IVEC Line, San Pablo Bay Pipeline, KLM Pipeline and other strategic assets
- Targeting the re-opening of San Pablo Bay Pipeline in 1Q27

Line 100 (P66) Acquisition Added Key Connections and Storage

- Improved operational reliability and commercial flexibility while creating a more efficient and integrated Central Valley operating platform
- 118-mile, 60 MBbl/d crude pipeline system connecting key Central Valley production hubs
- >1.0 MMBbl of oil storage capacity with integrated gathering, transportation and truck loading infrastructure







Production Sharing Contracts (PSC) at Higher Prices

CRC sees a difference of **~4.1 MBO/D** in net oil production **between $50/Bbl and $110/Bbl[1]**

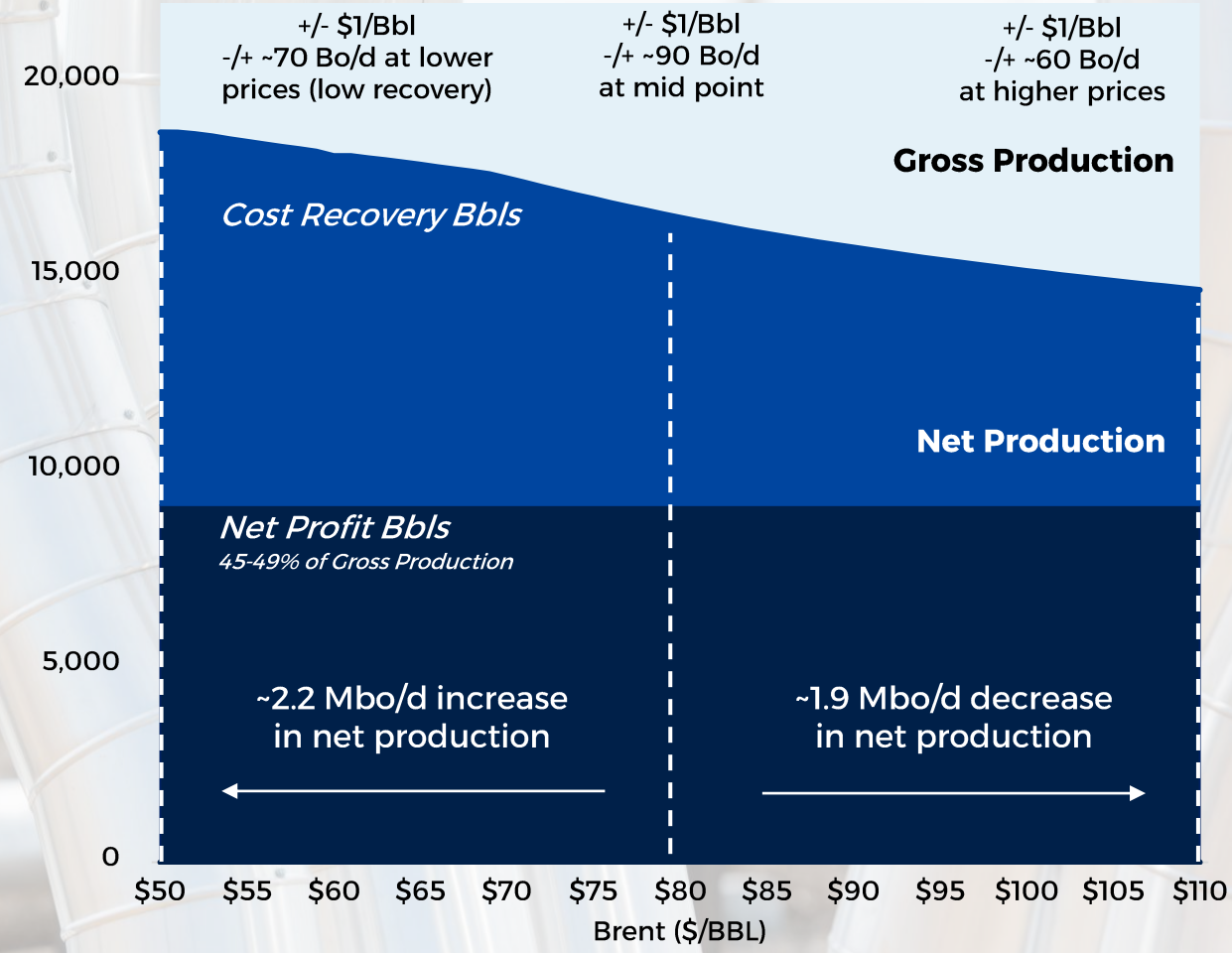
Approximately 12% of CRC's gross oil production is subject to PSC Mechanics:

- CRC pays its partners' share of operating and capital cost
- CRC **recovers 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 "profit barrels" are recovered

Effect of Oil Price on Net Production[1]

Wilmington Field Production (Bo/d)



See slide 45 for "Assumptions, Estimates and Endnotes".

Hedge Portfolio *(as of September 30, 2026)*

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

~65% of remaining 2026E net oil production hedged at an average Brent floor price of ~$65/Bbl[1]

OPERATIONS

~58% of remaining 2026E internal fuel consumption hedged at an average natural gas price of ~$4.23/MMBtu[1]

Oil Production	Units	4Q26E	1Q27E	2Q27E	3Q27E	4Q27E	2028E
Calls (Short) – Brent	Bbl/d	36,000	1,250	5,250	500	2,862	35,434
	$/Bbl	$83.51	$70.47	$72.07	$69.30	$69.79	$84.29
Swaps (Short) – Brent	Bbl/d	41,703	80,811	65,014	68,047	64,761	7,285
	$/Bbl	$67.98	$66.04	$65.54	$65.57	$65.56	$66.98
Puts (Long)[2] – Brent	Bbl/d	36,000	1,250	5,250	500	2,862	53,734
	$/Bbl	$61.11	$60.00	$61.90	$60.00	$60.00	$60.89

Natural Gas Consumption	Units	4Q26E	1Q27E	2Q27E	3Q27E	4Q27E	2028E
Swap (Long) – SoCal Border	MMBtu/d	9,908	14,044	-	-	-	-
	$/MMBtu	$4.84	$4.77	-	-	-	-
Swap (Long) – NWPL Rockies[3]	MMBtu/d	91,750	94,336	94,170	92,000	91,326	62,725
	$/MMBtu	$4.17	$4.18	$3.78	$3.88	$3.95	$3.59

Combined Portfolio	Units	4Q26E	1Q27E	2Q27E	3Q27E	4Q27E	2028E
Est. Hedge Contract Settlements[4]	$MM	($159)	($179)	($142)	($117)	($93)	($68)

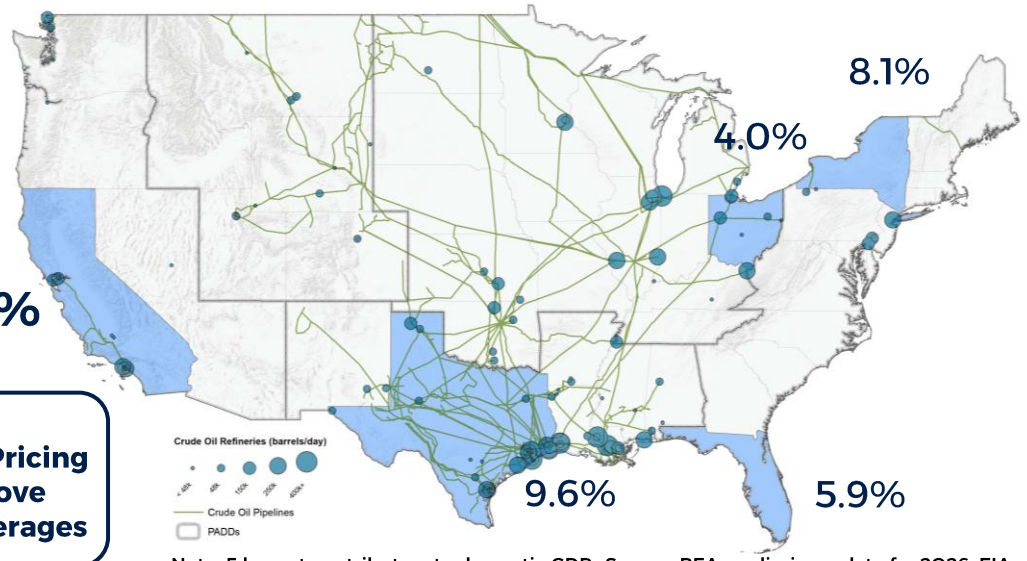
See slide 45 for "Assumptions, Estimates and Endnotes".

Commodity Price Realizations

- **Crude:** 3Q26 Brent crude oil prices were volatile as a result of the conflict in the Middle East, the conflict between Russia and Ukraine, and shifting expectations for cessation of hostilities or further escalation in each. California price realizations are expected to have troughed as alternative pathways to market are being actioned.
- **NGLs:** 3Q26 natural gas liquids prices pulled back slightly Q/Q on slightly higher realizations, while Y/Y, liquids prices have increased but have failed to keep pace with crude oil prices. California NGLs maintain a meaningful premium to the broader North American market.
- **Natural Gas:** Broadly, 3Q26 natural gas prices remained rangebound. California natural gas prices increased Q/Q as transportation alternatives out of key North American production basins came online requiring California to compete for out-of-state supplies. Market area storage remains elevated.

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

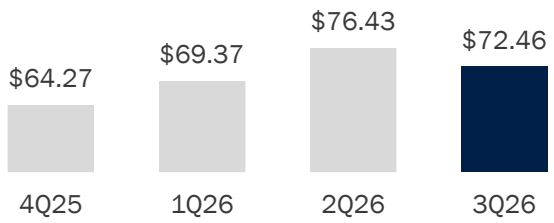
(amounts shown as % of U.S. domestic GDP)



California Commodity Pricing Generally Above Domestic Averages

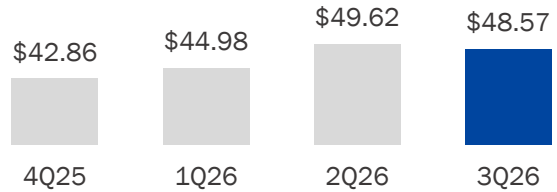
Note: 5 largest contributors to domestic GDP. Source: BEA, preliminary data for 2Q26; EIA

Oil w/ Hedges ($/BBL)



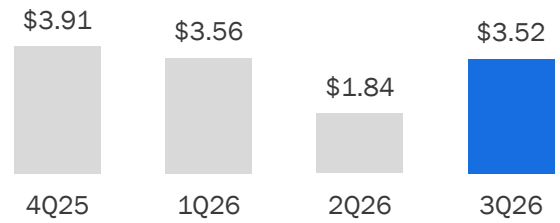
	4Q25	1Q26	2Q26	3Q26
Average Benchmark Prices[1]	$63.08	$77.90	$96.87	$91.36
% of Benchmark[1]	97%	96%	95%	91%
Hedge Settlements	$3.13	($5.16)	($15.12)	($10.96)
Average Realized Prices[2]	$64.27	$69.37	$76.43	$72.46

NGLs ($/BBL)



	4Q25	1Q26	2Q26	3Q26
	$63.08	$77.90	$96.87	$91.36
	68%	58%	51%	53%
	-	-	-	-
	$42.86	$44.98	$49.62	$48.57

Natural Gas ($/MCF)



	4Q25	1Q26	2Q26	3Q26
	$3.55	$5.04	$2.90	$2.96
	110%	71%	63%	119%
	-	-	-	-
	$3.91	$3.56	$1.84	$3.52

See slide 45 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 late-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.

Sustainability is Embedded in Our Operations

Near-Term Ambition

≥20% by 2035

from 2020 Baseline

Reduction in Average Carbon Intensity of Oil & Gas Operations

Long-Term Goal

≥80% by 2045

from 2020 Baseline

Reduction in Scope 1 & 2 Emissions

Responsible Net Zero

Goal to Reduce Absolute Scope 1 & 2 Emissions, and Neutralize Remaining Emissions[1]

2025 Sustainability Update

Climate

~25%

Reduction in Scope 1 and 2 emissions vs 2020 baseline[2]

Stewardship

"Grade A"

MiQ certification rating for the majority of operations[3]

Carbon

~409MMT

CO_2 emission permit volumes submitted to the EPA[4]

Water

~4.6B Gal

Treated, reclaimed water delivered to California; ~3x internal consumption

Community

>$2.0MM

Charitable donations to support local communities

Governance

~30%

Executive compensation tied to ESG-related goals

See slide 45 and 46 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/MJ	Grams of CO_2 Equivalent per Megajoule of Energy Produced
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
MOIC	Multiple on Invested Capital
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
SEC	United States Securities and Exchange Commission
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) Source: EIA, total energy consumption estimates 2024.
2) Data reflect reserves and annual production volumes as of December 31, 2025 using SEC Prices of $69.38 per barrel for oil and $3.39 per MMBtu for natural gas. CRC's production volumes include Berry Corporation's volumes for 14 days following the transaction close. Production amounts used are reported results and are not presented on a pro forma basis. Information includes Uinta assets that were owned as of year-end 2025 and that CRC expects to divest by year-end 2026.
    - Proved Reserves: Proved developed (PD) reserves include proved developed producing (PDP) and proved developed non-producing (PDNP) reserves.
    - Probable Reserves: Probable reserves are those reserves that are less certain to be recovered than proved reserves but, when aggregated with proved reserves, are as likely as not to be recovered. Probable reserves are subject to greater uncertainty regarding recoverability and economic viability and may not ultimately be recovered. Estimates of probable reserves have not been prepared in accordance with SEC definitions applicable to proved reserves and should not be construed as equivalent thereto. CRC's probable reserves are internally prepared estimates, are not independently audited, and are not subject to the same internal control framework applicable to proved reserves. A reserve adjustment factor has not been applied to PV-10, a non-GAAP measure.
    - CRC's proved reserves totaled 654 MMBOE and probable reserves totaled 526 MMBOE at 2025 SEC pricing (after adjustments for price realizations).
    - Reserve estimates are inherently uncertain and constitute forward-looking statements based on assumptions regarding commodity prices, costs, development timing, and reservoir performance; actual results may differ materially. Estimates of future net revenues should not be construed as fair market value. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves require the application of professional judgment and geological and engineering knowledge to assess whether specific classification criteria have been satisfied. CRC's estimates of proved and probable reserves are presented herein because management believes it is useful information that is widely used by the investment community in the valuation, comparison and analysis of companies. However, we note that the SEC prohibits companies from aggregating proved and probable reserves in filings with the SEC due to the different levels of certainty associated with each reserve category.
3) Total year 2026E estimates assume a 4Q26E Brent price of $102.90 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.25 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 15 of CRC's 3Q26 presentation for 4Q26E guidance.
4) 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.
5) CRC is currently subject to litigation regarding the environmental impact report (EIR) prepared under CEQA for the CTV I project. The Kern County Superior Court recently issued a ruling setting aside the certification of the EIR among other items. The ruling is not yet final and its impact on the existing operations at CTV I is uncertain.

Slide 3:

- Information includes Uinta assets that were owned as of year-end 2025 and that CRC expects to divest by year-end 2026.
- Proved Reserves: Proved developed (PD) reserves include proved developed producing (PDP) and proved developed non-producing (PDNP) reserves.
- Probable Reserves: Probable reserves are those reserves that are less certain to be recovered than proved reserves but, when aggregated with proved reserves, are as likely as not to be recovered. Probable reserves are subject to greater uncertainty regarding recoverability and economic viability and may not ultimately be recovered. Estimates of probable reserves have not been prepared in accordance with SEC definitions applicable to proved reserves and should not be construed as equivalent thereto. CRC's probable reserves are internally prepared estimates, are not independently audited, and are not subject to the same internal control framework applicable to proved reserves. A reserve adjustment factor has not been applied to PV-10, a non-GAAP measure.
- CRC's proved reserves totaled 654 MMBOE and probable reserves totaled 526 MMBOE at 2025 SEC pricing (after adjustments for price realizations) of $69.38 per barrel of oil and $3.39 per MMBtu of natural gas.

Assumptions, Estimates and Endnotes

Slide 3 (Cont.):

- Reserve estimates are inherently uncertain and constitute forward-looking statements based on assumptions regarding commodity prices, costs, development timing, and reservoir performance; actual results may differ materially. Estimates of future net revenues should not be construed as fair market value. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves require the application of professional judgment and geological and engineering knowledge to assess whether specific classification criteria have been satisfied. CRC's estimates of proved and probable reserves are presented herein because management believes it is useful information that is widely used by the investment community in the valuation, comparison and analysis of companies. However, we note that the SEC prohibits companies from aggregating proved and probable reserves in filings with the SEC due to the different levels of certainty associated with each reserve category.
- Peer Groups: "Canadians" includes: ARX, ATH, BIR, BTE, CNQ, CVE, IMO, NVA, PSK, SCR, SU, TOU, TPZ and WCP. "US Shale" includes: AR, BKV, CHRD, CNX, CRK, EQT, EXE, MTDR, NOG, PR, RRC, SM and VNOM. "Large Integrated" includes: BP, CVX, ENI, EQNR, PBR, SHEL, TTE and XOM. "Large US" includes: COP, DVN, FANG and OXY. "Offshore" includes: HBR, KOS, TALO, VAR and WTI. "International / US" includes: APA, EOG and MUR. Source: Company reports.

1) Enterprise value calculated using net debt of $1,265MM (as of September 30, 2026) plus market capitalization as of November 6, 2026 using 88.3MM shares outstanding.
2) PV-10 of proved reserves ($8.7B) and probable reserves ($5.7B) as of December 31, 2025 were calculated using SEC prices (after adjustments for price realizations) of $69.38 per barrel of oil and $3.39 per MMBtu of natural gas.
3) PV-10 of proved reserves ($10.3B) and probable reserves ($6.9B) as of December 31, 2025 were calculated using assumed prices (after adjustments for price realizations) of $75.00 per barrel of oil and $3.00 per MMBtu of natural gas and held flat. PV-10 using assumed prices was prepared on the same basis as the PV-10 using SEC prices. Investors should be careful to consider strip prices as an addition to, and not as a substitute for, SEC prices (as defined below), when considering our reserves.
4) PV-10 of proved reserves ($13.0B) and probable reserves ($8.9B) as of December 31, 2025 were calculated using assumed prices (after adjustments for price realizations) of $85.00 per barrel of oil and $3.00 per MMBtu of natural gas and held flat. PV-10 using assumed prices was prepared on the same basis as the PV-10 using SEC prices. Investors should be careful to consider strip prices as an addition to, and not as a substitute for, SEC prices (as defined below), when considering our reserves.
5) CRC data reflect reserves and annual production volumes as of December 31, 2025. CRC's production volumes include Berry Corporation's volumes for 14 days following the transaction close. Production amounts used are reported results and are not presented on a pro forma basis. Peer reserves and production data reflect reserves and annual production volumes as of December 31, 2025.

Slide 4:

1) Proved reserves estimated as of December 31, 2025 using SEC Prices of $69.38 per barrel for oil and $3.39 per MMbtu for natural gas. For more information on CRC's proved reserves, including a reconciliation to the most comparable GAAP measure, please see CRC's Forms 10-K for the fiscal year ended December 31, 2025.
2) Proved developed (PD) reserves include proved developed producing (PDP) and proved developed non-producing (PDNP) reserves.
3) Calculated using 2025 net production.
4) Uinta Basin production for full-year 2024 and the first nine months of 2025 is derived from Berry Corporation's publicly reported data prior to its merger with California Resources Corporation. 4Q25 net production reflects CRC internal estimates following the closing of the merger and is unaudited. These amounts may not reconcile to CRC's consolidated reported production or pro forma financial results.

Slide 5:

1) Source: EIA.

Slide 6:

1) Source: California Energy Commission.

Slide 7:

1) Source: EIA Natural Gas Consumption by End Use.
2) Source: Southern California Gas Company California Gas Report.

Assumptions, Estimates and Endnotes

Slide 8:

1) CRC is currently subject to litigation regarding the environmental impact report (EIR) prepared under CEQA for the CTV I project. The Kern County Superior Court recently issued a ruling setting aside the certification of the EIR among other items. The ruling is not yet final and its impact on the existing operations at CTV I is uncertain.
2) Includes 120 MW attributable to CRC's 50% interest in the Midway Sunset Power Plant.
3) Source: Company reports.

Slide 9:

1) Source: California Energy Commission.

Slide 11:

1) Development of a CO_2 pipeline system is subject to further acquisition of all necessary land rights, permitting, engineering, construction and significant capital expenditures over a multi-year period. No assurance can be given that any such development will occur.
2) MOUs are non-binding agreements. The projects and transactions described in an MOU 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.
3) 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.
4) 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.
5) Source: FactSet as of October 30, 2026. Peers include APA, BKV, CHRD, CRK, CRGY, GPOR, KOS, MGY, MTDR, MUR, NOG, RRC, SOC, SM, TALO and VET.

Slide 12:

1) Estimated 2027 adjusted EBITDA is based on CRC's projections for Crimson and: (i) assumes the acquired pipeline systems continue to operate at current levels (except for the San Pablo Bay pipeline where an increase in throughput is projected for 2027), (ii) assumes transportation rates consistent with existing tariffs (including contemplated increases, a portion of which are interim until rate case settlement), (iii) includes payments made by CRC as a shipper on certain of the acquired pipelines, and (iv) does not include any material capital expenditures for that period. CRC has not included a reconciliation of this non-GAAP measure to its nearest GAAP equivalent because it cannot do so without unreasonable effort and any attempt to do so would be inherently imprecise.
2) Initial purchase price excludes $7 million of preliminary purchase price adjustments. The final purchase price remains subject to certain adjustments.
3) Development of a CO2 pipeline system is subject to further acquisition of all necessary land rights, permitting, engineering, construction and significant capital expenditures over a multi-year period. No assurance can be given that any such development will occur.
4) The transaction has an effective date of July 1, 2026, is subject to receipt of certain third-party consents and customary closing conditions, and is expected to close by year-end 2026. Following the closing of the transaction, CRC expects to provide additional financial and operating guidance.
5) Before transaction costs and customary purchase price adjustments. CRC bears the following post-effective date cost of approximately $4MM in drilling and completions capital, and other customary purchase price adjustments.
6) Reallocated capital represents $46MM of 2026 budgeted capital reduced by $11MM in actual amounts spent.

Slide 13:

1) Total year 2026E estimates assume a 4Q26E Brent price of $102.90 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.25 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 15 of CRC's 3Q26 presentation for 4Q26E guidance.
2) 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.

Assumptions, Estimates and Endnotes

Slide 14:

1) 2023 information represents the combined costs for legacy CRC, legacy BRY and legacy Aera, and excludes presentation adjustments, transaction adjustments and financing adjustments. Operating costs for Aera have been restated using CRC's accounting classification.
2) Total year 2026E estimates assume a 4Q26E Brent price of $102.90 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.25 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 15 of CRC's 3Q26 presentation for 4Q26E guidance.
3) Includes approximately 600 employees in the C&J Well Services business.

Slide 15:

1) Information relative to the midpoint of the Berry merger synergy target of $90MM - $100MM.

Slide 16:

1) Total year 2026E estimates assume a 4Q26E Brent price of $102.90 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.25 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 15 of CRC's 3Q26 presentation for 4Q26E guidance.
2) CRC is currently subject to litigation regarding the environmental impact report (EIR) prepared under CEQA for the CTV I project. The Kern County Superior Court recently issued a ruling setting aside the certification of the EIR among other items. The ruling is not yet final and its impact on the existing operations at CTV I is uncertain.
3) Subject to commodity prices and market factors.

Slide 17:

1) CRC is currently subject to litigation regarding the environmental impact report (EIR) prepared under CEQA for the CTV I project. The Kern County Superior Court recently issued a ruling setting aside the certification of the EIR among other items. The ruling is not yet final and its impact on the existing operations at CTV I is uncertain.
2) Estimate assumes a Brent price of $93.28 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.05 per Mcf.

Slide 18:

1) MOUs are non-binding agreements. The projects and transactions described in an MOU 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.
2) 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.

Slide 19:

1) Source: Enverus (October 2026) and internal estimates.
2) Source: EPA as of October 23, 2026, 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.

Slide 20:

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 as of October 30, 2026. Represents CRC's current annual dividend policy of $1.68 per share divided by CRC's share price as of October 30, 2026.

Assumptions, Estimates and Endnotes

Slide 21:

1) Total year 2026E estimates assume a 4Q26E Brent price of $102.90 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.25 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 15 of CRC's 3Q26 presentation for 4Q26E guidance.
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 revenue net of electricity generation expenses 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 22:

1) Available cash and cash equivalents excludes $13MM of restricted cash.
2) Liquidity on September 30, 2026 is calculated as $35MM of cash and cash equivalents (excluding $13MM of restricted cash) plus $1,460MM of borrowing capacity on CRC's revolving credit facility less $180MM in outstanding letters of credit.
3) Net leverage is calculated as 3Q26 net debt of $1,265MM (excluding restricted cash of $13MM) divided by LTM adjusted EBITDAX of $1,234MM.
4) Interest coverage is calculated as LTM adjusted EBITDAX of $1,234MM divided by LTM interest expense of $112MM.

Slide 24:

1) CTV VI is located in Central California but is shown in the Northern California due to map scale.
2) Source: California Air Resources Board, "Current California GHG Emission Inventory Data 2000–2023," 2025 edition.

Slide 25:

1) Source: EPA as of October 23, 2026, 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) CRC is currently subject to litigation regarding the environmental impact report (EIR) prepared under CEQA for the CTV I project. The Kern County Superior Court recently issued a ruling setting aside the certification of the EIR among other items. The ruling is not yet final and its impact on the existing operations at CTV I is uncertain.
3) 26R injection volumes as per the 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.
4) Source: CARB 2020.

Slide 27:

1) Source: Kern County Treasurer-Tax Collector.

Slide 28:

1) AllSource: Company reports.
2) Based on signed memoranda of understanding (MOUs) and existing CRC power assets.
3) Includes EPA Class VI permit estimated annual CO2 injection rates for CTV I 26R, CTV I A1-A2, CarbonFrontier and CTV VII.

Assumptions, Estimates and Endnotes

Slide 29:

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 30:

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

Slide 31:

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 32:

1) Source: CalGEM WellSTAR as of Oct 1, 2026.
2) Permits approved and wells online are Kern County only. Wells online include wells that had permits prior to KCEIR ruling.

Slide 34:

1) Net Production from Wilmington field only. Includes the effects of a development program in the Los Angeles basin.

Slide 35:

1) Subject to commodity prices and market factors.
2) Purchased and sold puts with the same strike price have been netted together.
3) NWPL volumes require transportation to where the gas is consumed. These costs are reflected in our 4Q26E transportation guidance. See slide 15 of CRC's 3Q26 presentation for 4Q26E guidance.
4) Represents estimated net cash settlement payments inclusive of premiums for derivative contracts and forward commodity prices as of September 30, 2026.

Slide 36:

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

Slide 38:

1) Planned use of either carbon offsets generated and claimed internally or carbon offsets purchased and claimed through the third-party carbon market (including California's Cap-and-Invest Program) for Scope 1 GHG emissions, and use of contractual instruments such as renewable energy certificates or carbon offsets for Scope 2 GHG emissions.
2) Excludes sustainability metrics related to Berry which merged with CRC on December 18, 2025, unless otherwise expressly noted.
3) MiQ certification covers production operations in the San Joaquin, Ventura and Los Angeles basins.

Assumptions, Estimates and Endnotes

Slide 38 (Cont.):

4) 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.

Forward-Looking / Cautionary Statements – Certain Terms

Forward-Looking Statements:

Information set forth in this communication, including financial estimates and statements as to the effects of the Berry Merger and the Crimson acquisition, constitute "forward-looking statements" within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 and other securities laws. All statements other than historical facts are forward-looking statements, and include statements regarding the benefits of the Berry Merger and the Crimson acquisition, CRC's future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and plans and objectives and intentions 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 based upon the current beliefs and expectations of the management of CRC and are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, projected 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 SEC. 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; changes in price realizations; integration efforts and projected synergies and other benefits in connection with the Berry Merger, Crimson acquisition and other acquisitions; divestitures and joint ventures, including the Uinta divestiture; regulatory actions and changes that affect the oil and gas industry generally and CRC in particular; the efforts of activists to delay or prevent oil and gas activities or the development of CRC's carbon management segment; changes in business strategy and the ability and financial resources to execute its capital plan in a timely manner; 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 and improve capital efficiencies; 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, transportation and storage projects, power projects and other renewable energy efforts, including those contemplated by the Bloom MOU; changes in transportation costs and CRC's ability to develop midstream opportunities; delays from government approvals and otherwise that could affect the timing of projects; the effects and outcome of litigation, including the CEQA litigation relating to the CTV I environmental impact report (EIR) and any resulting restrictions on CO_2 injection or delays to projects relying on the EIR, and the well stimulation treatment litigation; 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 date hereof, and CRC is under no obligation, and expressly disclaims any obligation to update, alter or otherwise revise any forward-looking statements, whether as a result of new information, future events or otherwise. This communication 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.

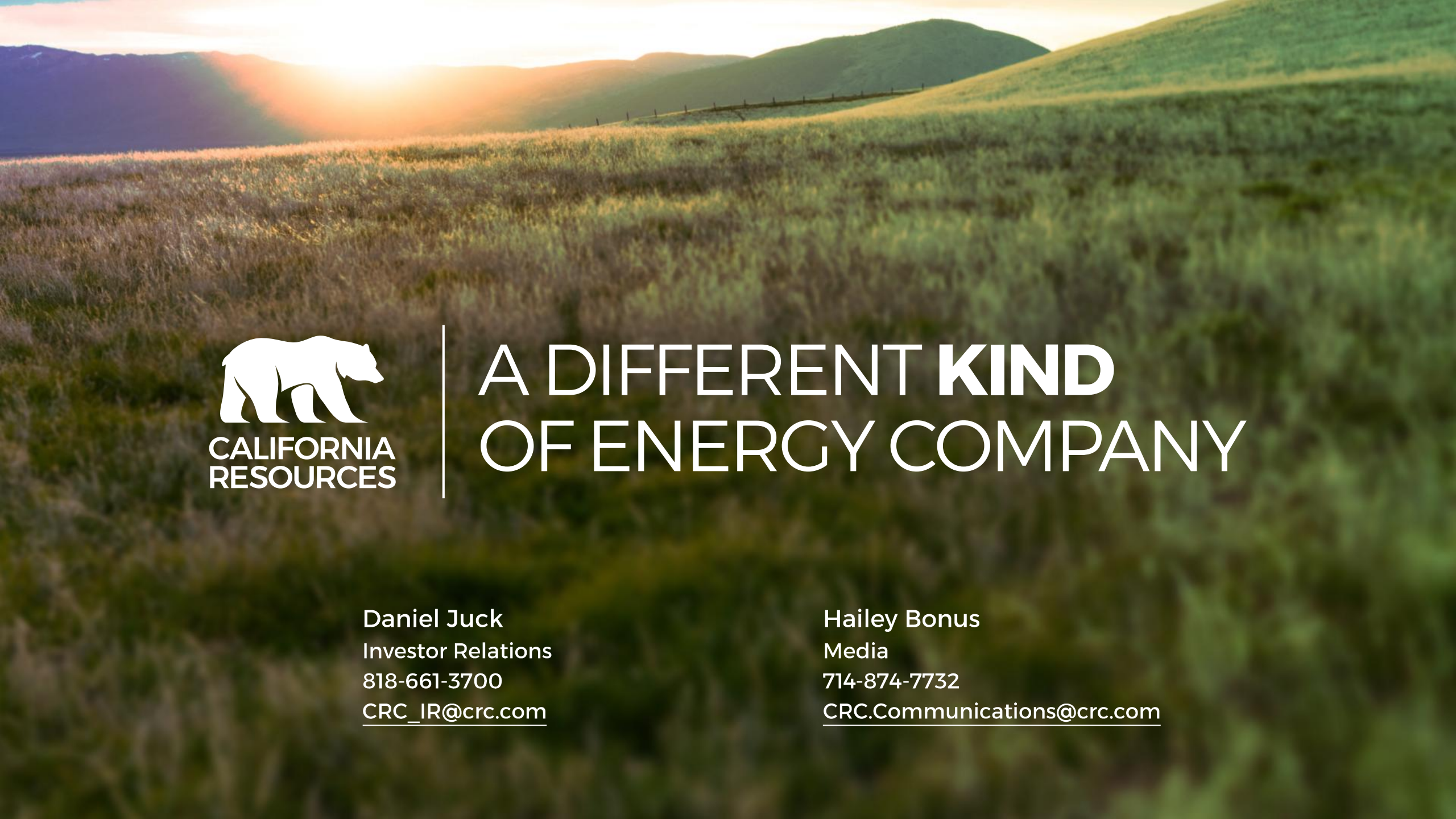
Forward-Looking / Cautionary Statements – Certain Terms

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, Drilling, Completion and Workover Capital, Reserve Replacement Ratio, per Bbl Brent O&G Only Breakeven Price, Operating Cash Flow Before WC Changes, Adjusted G&A Expense, Other Operating Expenses Net of Other Revenue, Margin from Purchased Commodities, Electricity Revenue Net of Electricity Generation Expenses, PV-10, Net Debt, Liquidity, Free Cash Flow, Free Cash Flow Before WC Changes, Net Leverage and Interest Coverage. 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. Additionally, this presentation includes forward-looking non-GAAP financial measures, including adjusted EBITDAX. CRC is unable to provide a reconciliation of such forward-looking non-GAAP measures to the most directly comparable forward-looking GAAP financial measures because certain information needed to reconcile these measures is dependent on future events, many of which are outside of CRC's control and cannot be reasonably predicted at this time. These items include, but are not limited to, changes in working capital, the timing and amount of capital accruals, and other non-cash or unusual items. Accordingly, a quantitative reconciliation is not available without unreasonable efforts.

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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