



Fourth Quarter and Full Year 2025 Results

March 2, 2026

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, 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, 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.

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Forward-Looking / Cautionary Statements – Certain Terms

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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, Cash Flow from Operations before WC Changes, Adjusted G&A Expense, Other Operating Expenses Net of Other Revenue, Margin from Purchased Commodities, Electricity Margin, PV-10, 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. Additionally, this presentation includes forward-looking non-GAAP financial measures. Due to the forward-looking nature of these measures, management cannot reliably or reasonably predict certain of the necessary components of the most directly comparable forward-looking GAAP measures without unreasonable effort, due to the inherent difficulty in quantifying certain amounts due to a variety of factors, including the unpredictability of commodity price movements and future charges or reversals outside the normal course of business which may be significant. Accordingly, we are unable to present a quantitative reconciliation of such forward-looking non-GAAP financial measures to their most directly comparable forward-looking GAAP financial measures.

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2025 – A Year of Outstanding Achievements

Highest Annual Adj. EBITDAX*, Free Cash Flow* and Shareholder Returns since 2021¹

Accretive Merger Expands Scale and Strengthens the Balance Sheet

Leading, Scalable Decarbonization Platform

Financial and Operating Highlights

Highest Adj. EBITDAX ¹ \$1,241MM <i>23% YoY Growth</i>	Highest Free Cash Flow ¹ \$543MM <i>53% YoY Growth</i>	Total Net Production 138MBoe/d <i>25% YoY Growth</i>
Delivered Highest Shareholder Returns ^{1,2} \$513MM <i>94% of Free Cash Flow *</i>	Share Repurchases ² \$377MM <i>8.3MM Shares</i>	Raised Dividend ² 5% <i>4th Consecutive Year of Annual Dividend Growth</i>
Substantially Completed CA's First CCS Project 100KMTPA <i>of CO₂ Emissions Anticipated in 2026</i>	CO ₂ Permit Volumes Submitted to the EPA >350MMT <i>through March 2026</i>	MiQ's Methane Emissions Performance Standard ³ Grade A <i>for Most of CA Operations</i>

2026 Estimated Outlook¹

<p>Adj. EBITDAX*</p> <p>\$970 – \$1,070MM</p> <p><i>~2/3 of oil production hedged at ~\$65/Bbl²</i></p>	<p>YoY Production Growth³</p> <p>12%</p> <p><i>152-157MBoe/d, 81% oil 4 rigs</i></p>
<p>Operating Costs</p> <p>\$1,400 – \$1,500MM</p> <p>G&A</p> <p>\$350 – \$370MM</p>	<p>Berry Merger Synergies</p> <p>\$80 - \$90MM</p> <p><i>Included in 2026E guidance</i></p>
<p>Total Capital</p> <p>\$430 – \$470MM</p> <p><i>\$280 - \$300MM in drilling, completion and workover capital¹</i></p>	<p>CO₂ Injection from CA's First CCS Project</p> <p>100KMTPA</p> <p><i>Expecting the release of additional EPA Class VI draft permits⁴</i></p>

Operational and Strategic Focus

Focused Execution and Cost Discipline

Strategic Capital Deployment Across Portfolio

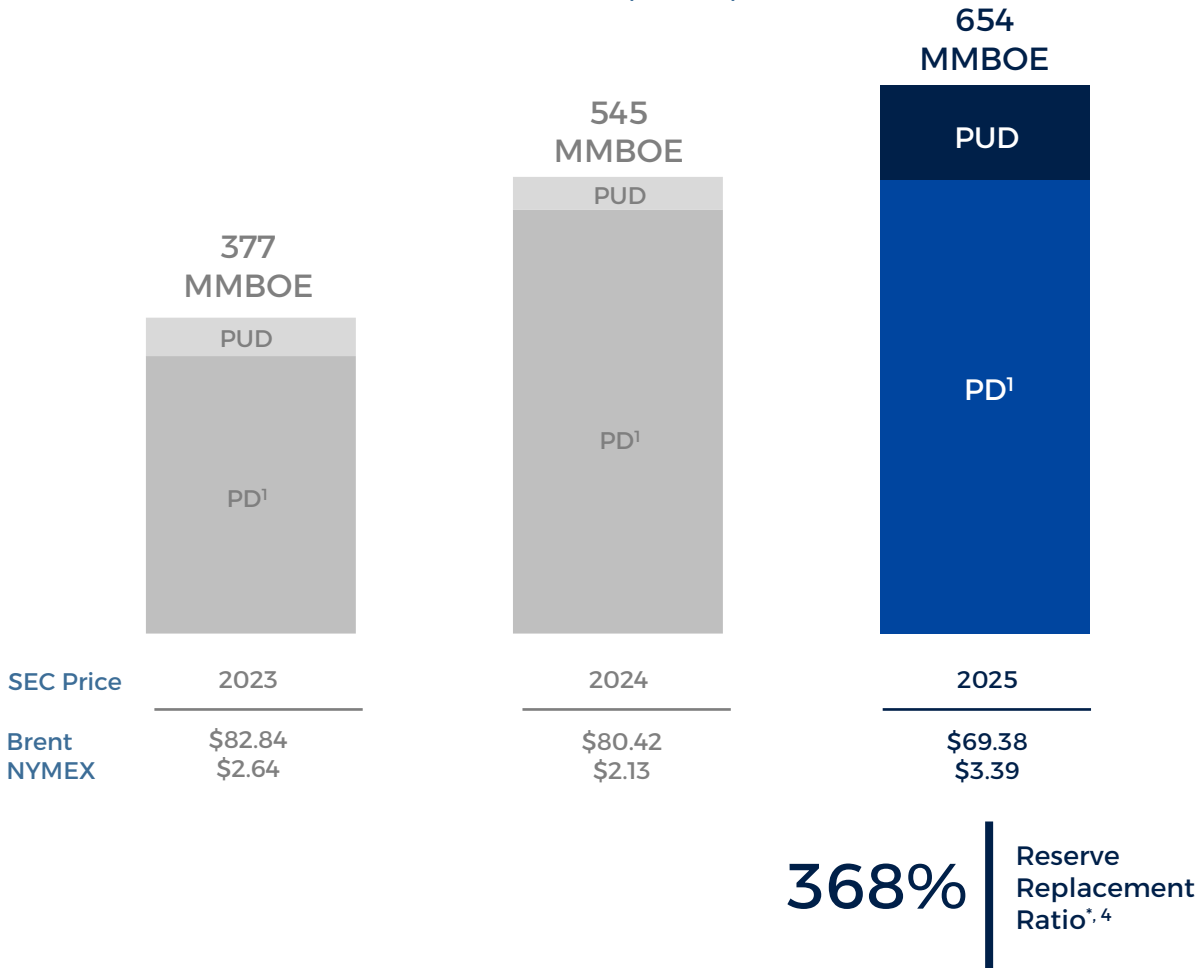
Durable Value Supported by Core Assets,
Long-Term Demand Fundamentals, and
Disciplined Shareholder Returns



2025 Reserves Demonstrate Robust Growth

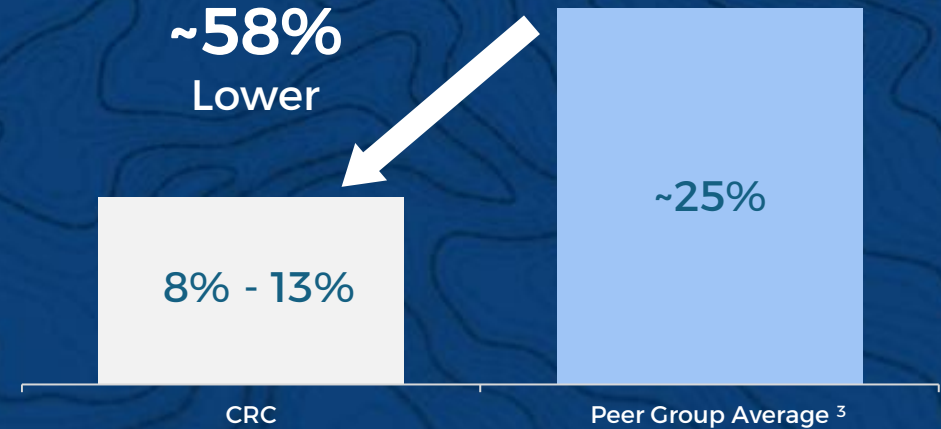
PD¹ and PUD Reserves Up 7% and 190% YoY, Respectively Despite ~14% Brent Price Decline

Proved Reserves² (MMBOE)



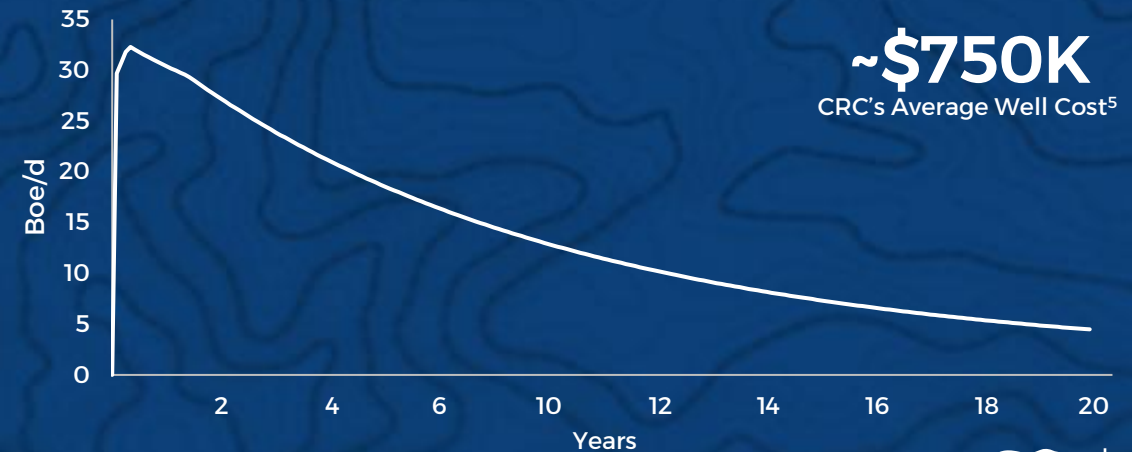
Meaningfully Lower Estimated Base Decline Rate vs Peers

Estimated Corporate PDP Decline Rates (%)



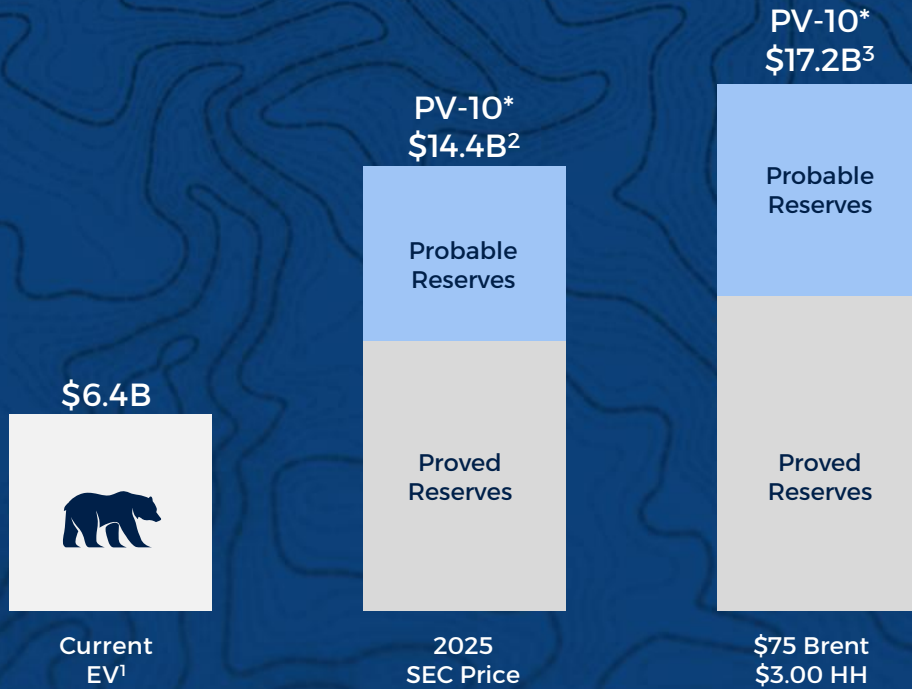
Low Base Declines Reduce Capital Intensity

CRC's Average Well Production⁵ (Boe/d)



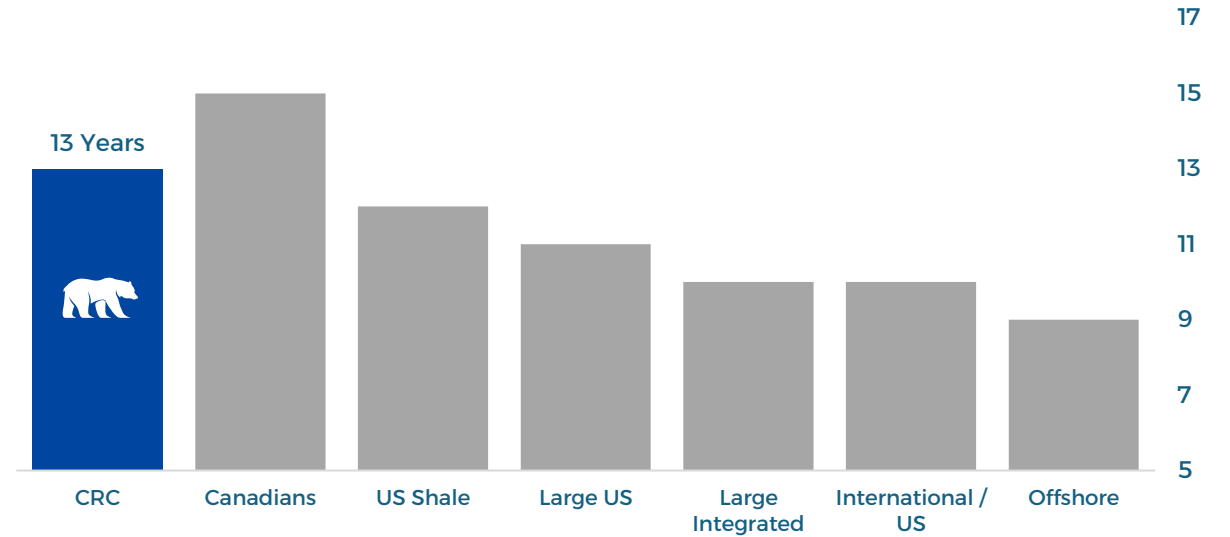
Significant Value From World-Class Conventional Reservoirs

Material Upside From Long Duration Assets



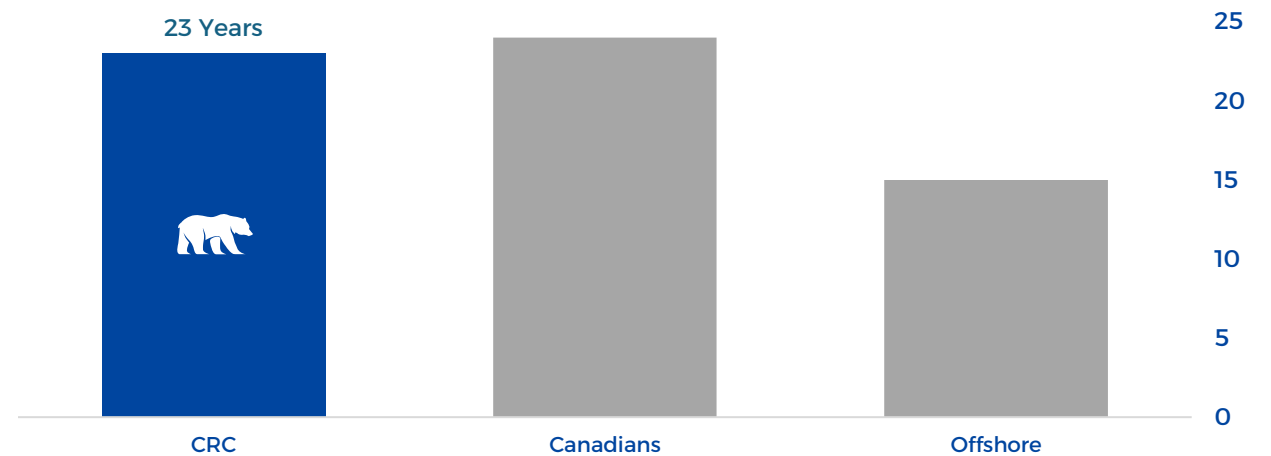
Long Proved Reserves Base

Proved Reserves / Annual Production (Years)⁴



Multi-Decade Conventional Runway

Proved + Probable Reserves / Annual Production (Years)⁴

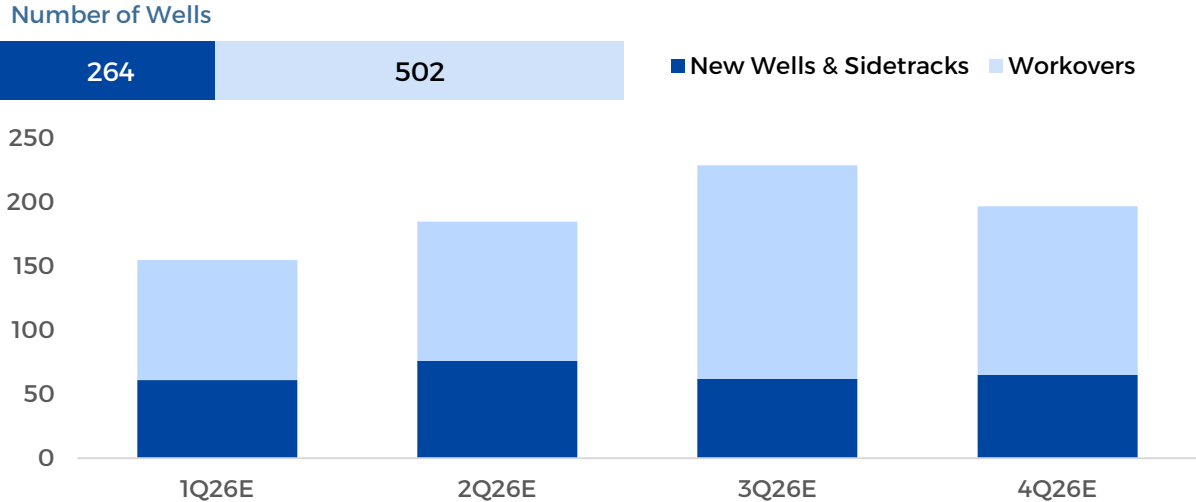


Low-Decline Base Enables Control and Operational Flexibility

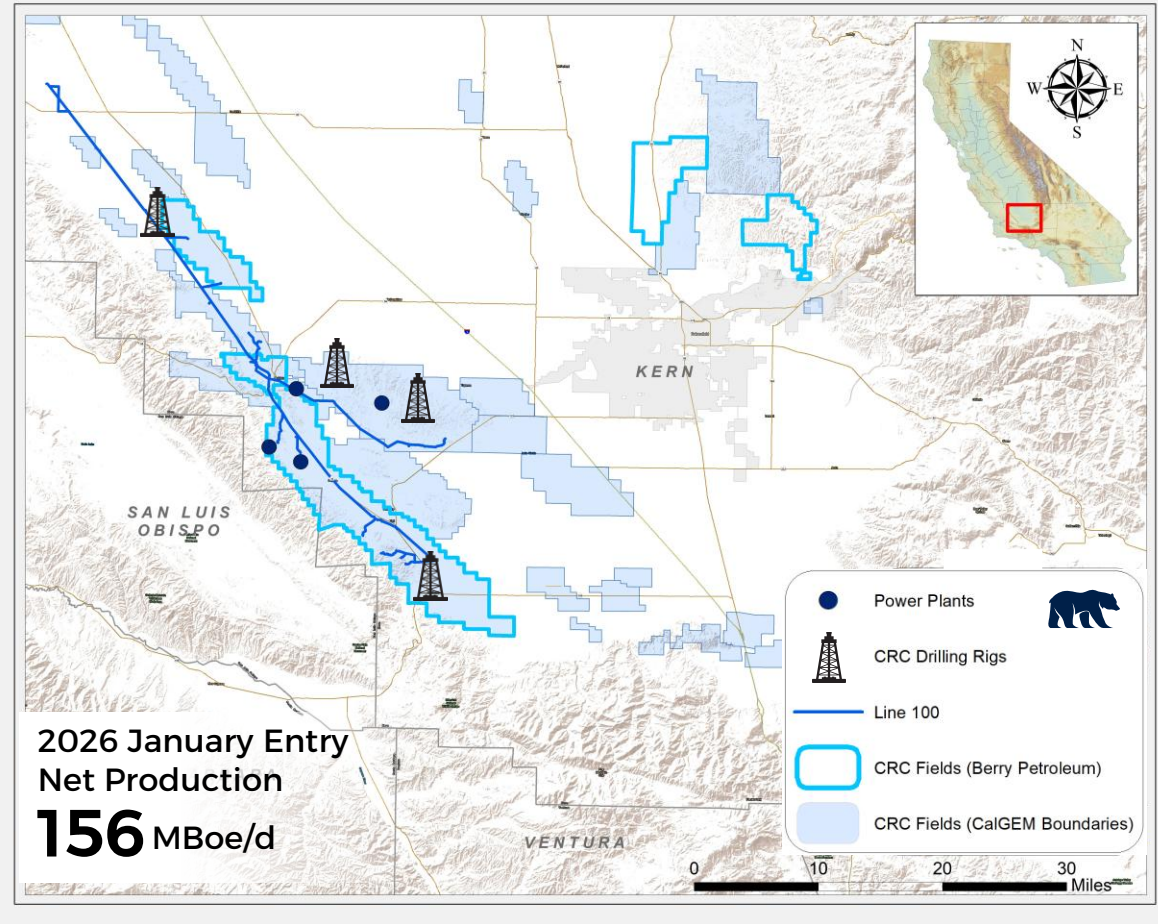
2026E Framework¹

- Targeting Entry-to-exit gross production decline ~2%; average ~4 rigs
- Focus on developing predictable conventional reservoirs
- Workovers and sidetracks expected to smooth quarterly variability
- Planned capital program provides flexibility to adapt to market conditions
- Continued focus on sustainable, efficiency gains to structurally reduce costs

2026E D&C and Workover Activity Cadence¹



Majority of 2026 Drilling Permits Secured



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

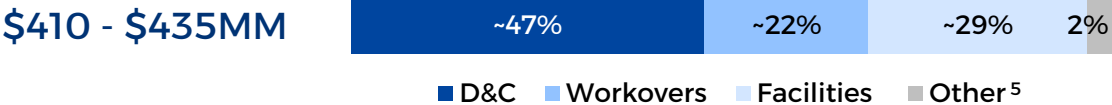


High-Return Development with Low Capital Intensity

2026E Development Program¹

- ~264 low-risk, high-value wells
- Consist of workovers, sidetracks and new wells (primarily 2H26) and hold the majority of permits necessary to undertake our 2026 capital program

2026E E&P Capital¹



Drilling Rig Assumptions

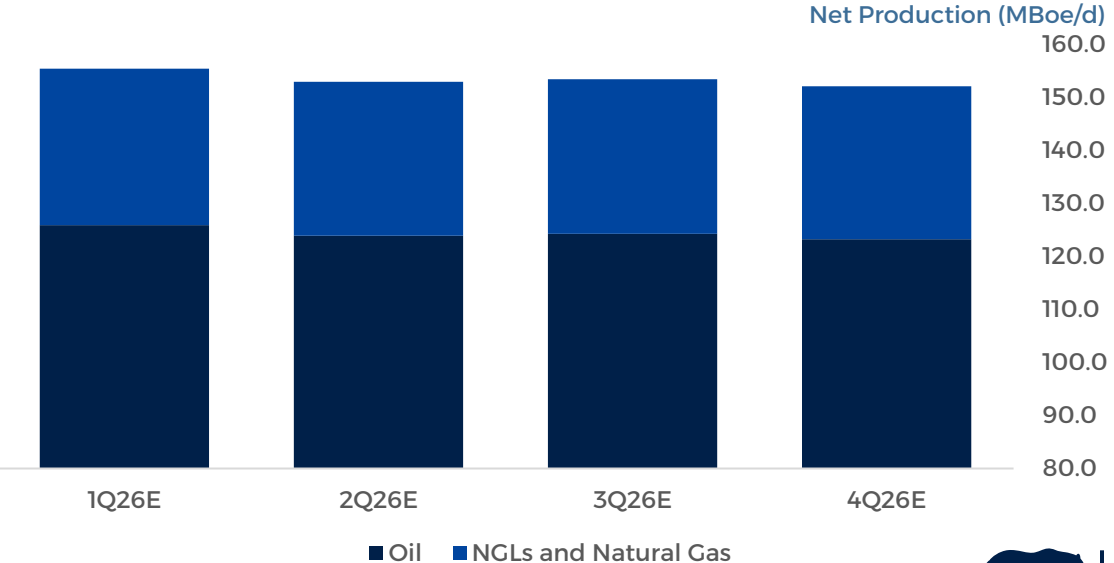
- \$50 - \$60MM D&C capital per rig per year
- ~1 rig ≈ ~1% annual production change

2026E O&G Program Economics^{1,2}

~49% IRR | **~3.8x MOIC³** | **~\$53** per Bbl Brent O&G Only Breakeven Price* Hedged⁴

Well Type		Brent >25% IRR (\$/Bbl)	WTI >25% IRR (\$/Bbl)
Workovers		~\$42	~\$38
New Drills <i>(Average of 2026E sidetracks and new wells)</i>		~\$44	~\$40

Consistent Production Profile in 2026E¹



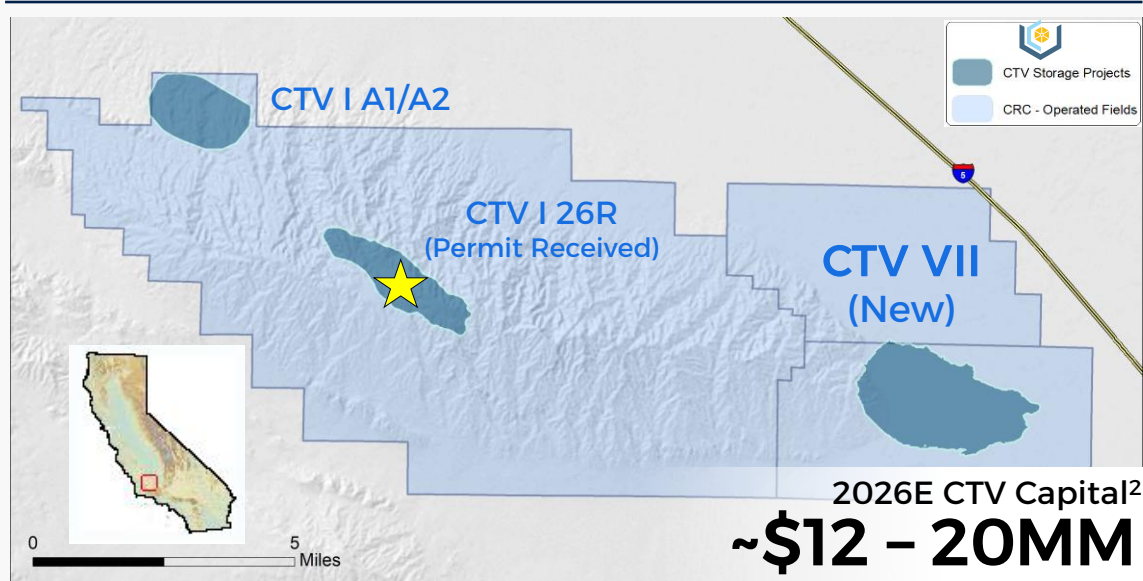
See slide 30 for “Assumptions, Estimates and Endnotes”.



Advancing Innovative Energy Solutions

- Signed MOUs¹ covering 6.8MMTPA of incremental CO₂ volumes in 2025 with leading industrial and power counterparties, exploring viable decarbonization solutions
- Delivered measurable year-one emissions reductions through CRC's "Football Without the Footprint" partnership with the Los Angeles Rams

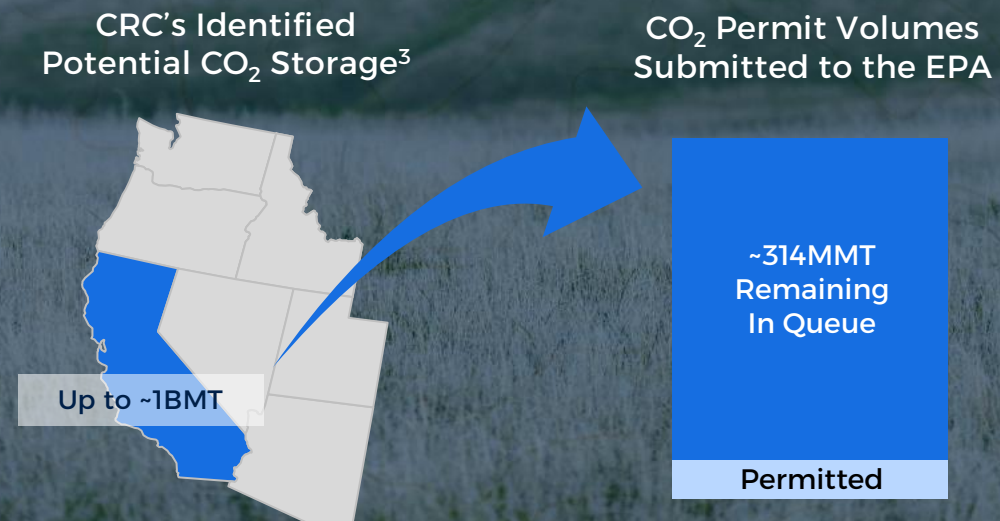
Scalable CO₂ Storage Adjacent to Elk Hills



“Best of the West”

California's Premier Carbon Management Provider

- Completed construction of carbon capture equipment at CRC's Cryogenic Gas Plant at Elk Hills – California's first CCS project
- Currently commissioning the facility and targeting first CO₂ injection in Spring 2026, subject to EPA approval
- New CTV VII Class VI application for ~27MMT was submitted to the EPA, bringing total submitted permit volumes to ~352MMT
- Planning to submit applications for additional reservoirs while advancing applications already in queue



See slide 31 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

CA's first CO₂ injection expected in Spring 2026, subject to EPA approval

Current Market Dynamics

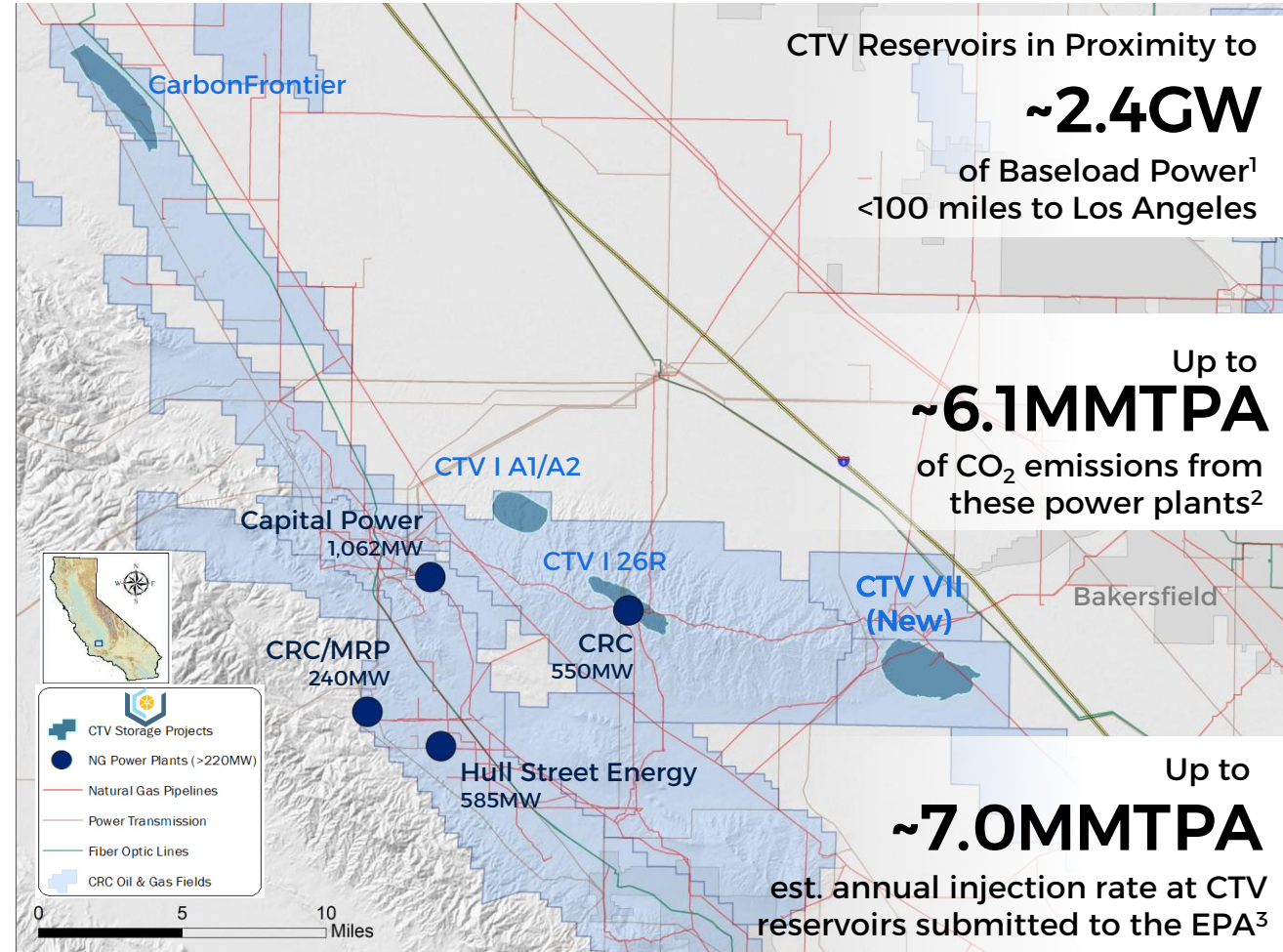
Opportunity	Customers	Clean Premium
1 FTM Utility Sale	Utilities	✓
2 FTM Sale	Existing Data Centers, Industrials	✓
3 BTM Industry Sale	New Data Centers, Industrials	✓

See slide 31 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 CO₂ storage reservoirs
- Possible CO₂ pipeline connectivity

Powered Land

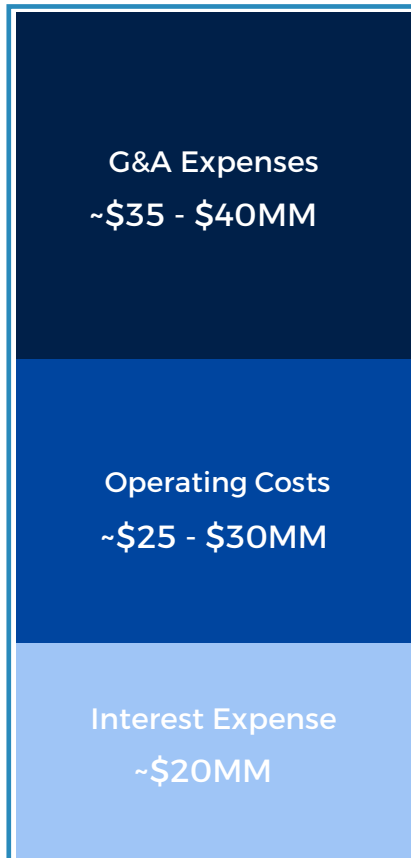


Structural Cost Reductions Drive Margin Expansion

2026 Estimated Berry-Related Synergies

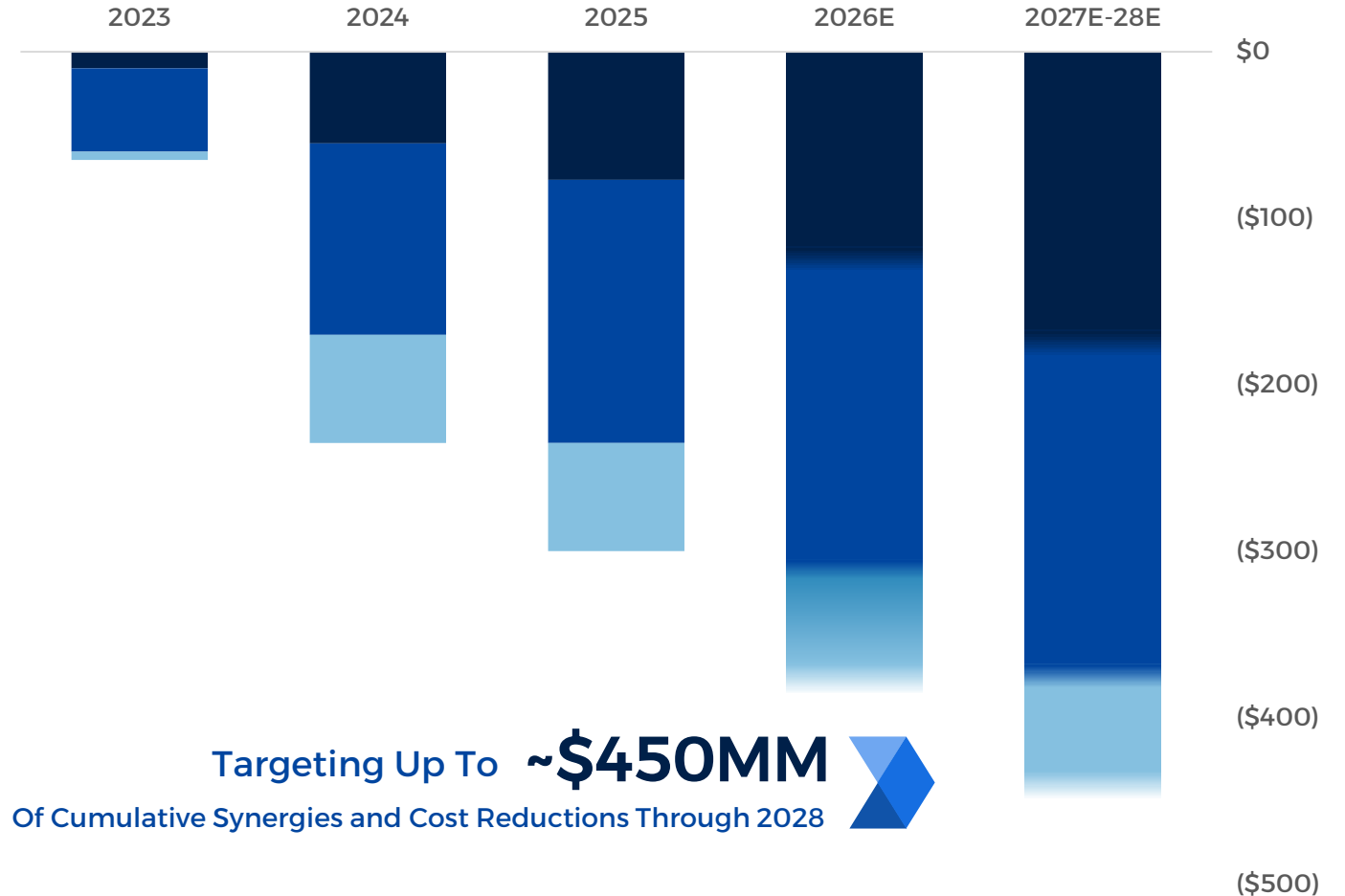
Included in 2026E Guidance (\$MM)

\$80 - 90MM



Benefits of a Leaner CRC

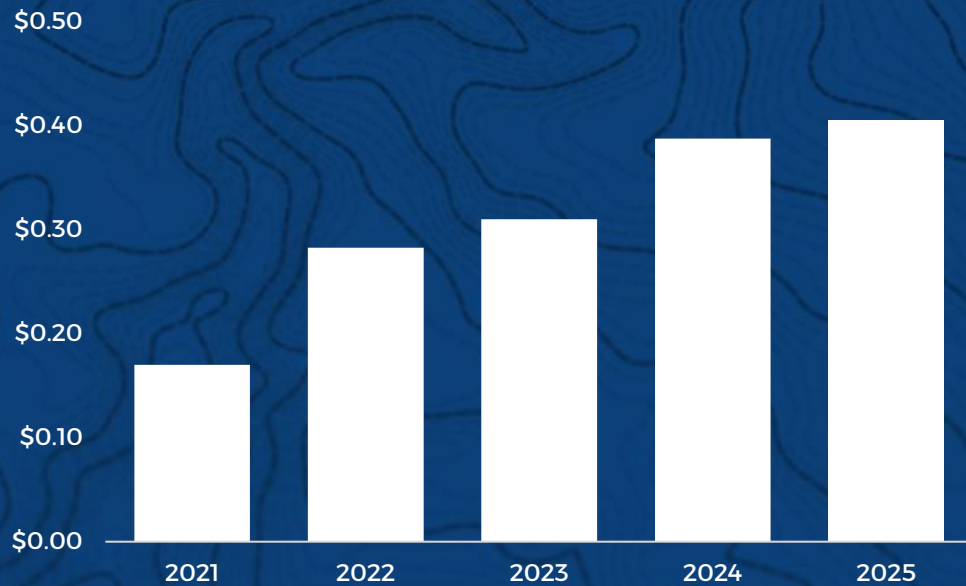
Targeted Cumulative Synergies and Structural Cost Reductions (\$MM)



Disciplined Capital Allocation...

Historical Dividend Growth

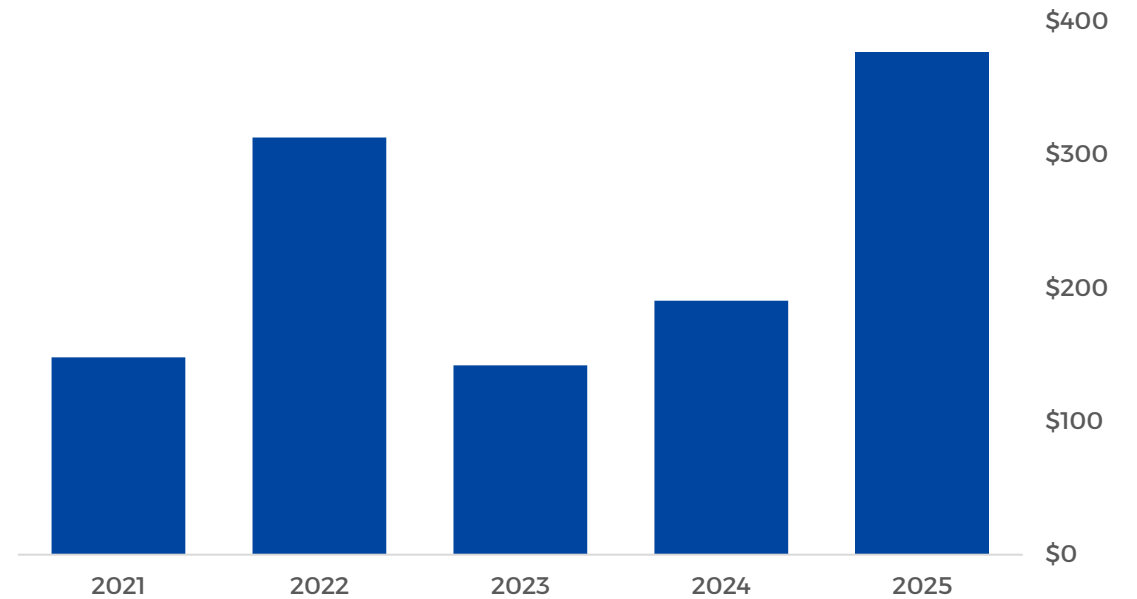
Quarterly Dividend at Year End (\$/sh)¹



...Drives Shareholder Returns

Maintaining Long-Term Focus, Delivering Buybacks

Share Repurchases (\$MM)¹



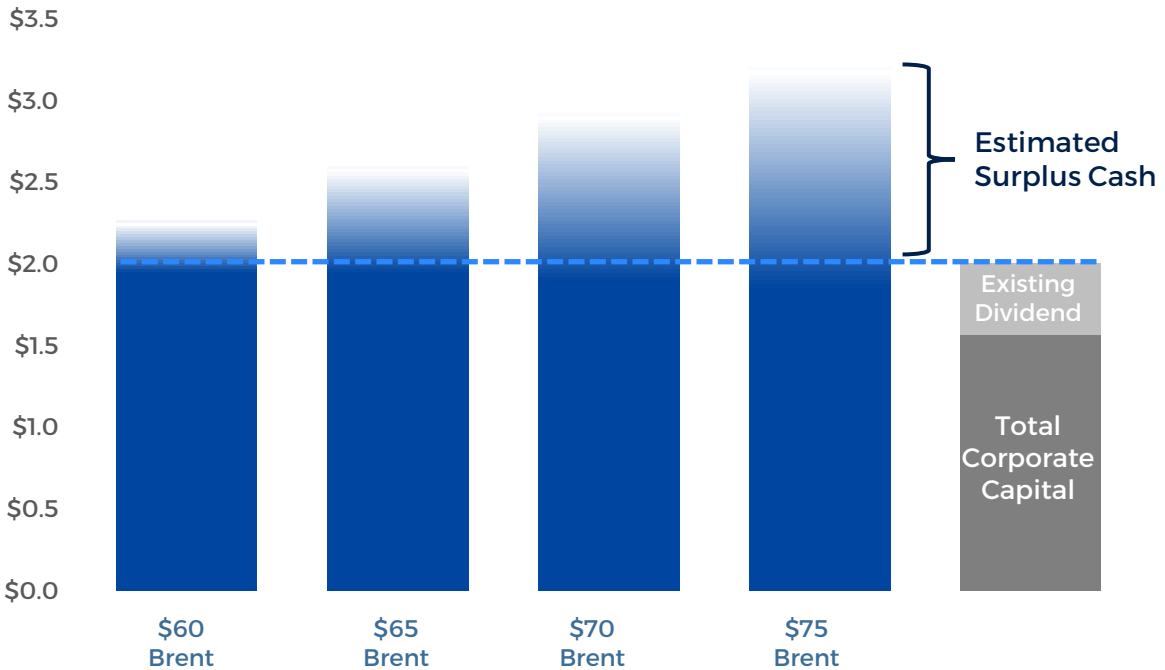
Raised SRP Authorization by **\$430MM**
to \$1.78B and extended through year-end 2027

“California Comeback” Drives Long-Term Value Opportunity

Maintenance Activity Supports Cash Generation Across Commodity Cycles¹

Breakeven Price <i>(Hedged)</i>	Brent <i>(\$/Bbl)</i>	WTI <i>(\$/Bbl)</i>
Total Corporate Capital	~\$60	~\$56
O&G Only	~\$58	~\$54

Cumulative 2026E - '28E Cash Flow from Operations Before WC Changes* (\$B)
Maintenance Rig Activity : 7 Rigs 2027 Onwards With an Est. Annual Maintenance
D&C and Workover Capital of ~\$485MM



Note: “Before WC Changes” means “Before Net Changes in Operating Assets and Liabilities”.
See slide 31 for “Assumptions, Estimates and Endnotes”.

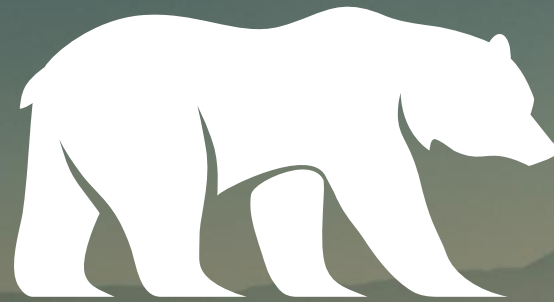
Durable Approach

Advantaged Portfolio, Focused Execution and
Disciplined Capital Allocation

Continuous Cost Management and Resilient
Balance Sheet Strength Through The Cycle

Historical Track Record of Robust Shareholder
Returns via Dividends and Opportunistic Buybacks





Results, Guidance & Capital Structure



4Q25 and FY25 Results

Commodity	4Q25 Actual	2025 Actual
Brent (\$/Bbl)	\$63.08	\$68.22
Brent Realized Price with Hedge (\$/Bbl)	\$64.27	\$67.51
Oil Realization without Derivative Settlements (% of Brent)	97%	98%
Operational and Financial		
Net Production (MBoe/d)	137	138
Net Oil Production (% of Total)	80%	79%
Operating Costs (\$MM)	\$325	\$1,252
G&A Expenses (\$MM)	\$95	\$333
Adj. G&A Expenses* (\$MM)	\$89	\$309
Taxes Other Than on Income (\$MM)	\$55	\$242
Other Operating Expenses Net of Other Revenue ¹	\$75	\$187
Total Capital (\$MM)	\$120	\$322
Adj. EBITDAX* (\$MM)	\$251	\$1,241
Operating Cash Flow Before WC Changes*	\$211	\$1,006
Free Cash Flow*	\$115	\$543
Other Items		
Margin from Purchased Commodities ²	\$13	\$56
Electricity Margin ³	\$40	\$195
Transportation Costs (\$MM)	\$20	\$79
Total Return of Cash to Shareholders⁴ (\$MM)		
Share Repurchases (\$MM)	\$25	\$377
Dividends Paid (\$MM)	\$34	\$136
Total Shareholder Returns (\$MM)	\$59	\$513

Impressive Results

- 25% YoY Production Growth in 2025
- Highest Annual Adj. EBITDAX* and Free Cash Flow since 2021^{*, 5}
- Highest Annual Shareholder Returns since 2021^{4, 5}

4Q25 and 2025 Results include ~14 days of BRY contribution following the transaction close on December 18, 2025

Note: "Before WC Changes" means "Before Net Changes in Operating Assets and Liabilities". See slide 31 for "Assumptions, Estimates and Endnotes".

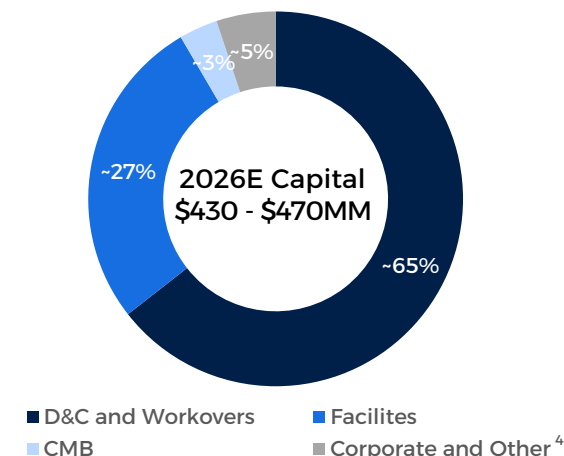


2026E Guidance *(as of March 2, 2026)*

CRC Guidance	1Q26E Consolidated	Oil and Natural Gas	Carbon Management	2026E Consolidated	Oil and Natural Gas	Carbon Management
Net Production (MBoe/d) ~81% Oil	155 - 157			152 - 157		
Margin from Purchased Commodities ¹ (\$MM)	\$15 - \$20			\$60 - \$75		
Electricity Revenue (\$MM)	\$6 - \$16			\$55 - \$85		
Electricity Generation Expenses (\$MM)	\$2 - \$6			\$15 - \$25		
Operating Costs (\$MM)	\$355 - \$375	\$355 - \$375		\$1,400 - \$1,500	\$1,400 - \$1,500	
G&A (\$MM)	\$90 - \$100	\$12 - \$16	\$2 - \$4	\$350 - \$370	\$50 - \$60	\$6 - \$12
<i>Adjusted G&A¹ (\$MM)</i>	<i>\$85 - \$90</i>	<i>\$12 - \$16</i>	<i>\$2 - \$4</i>	<i>\$315 - \$330</i>	<i>\$50 - \$60</i>	<i>\$6 - \$12</i>
Depreciation, Depletion and Amortization (\$MM)	\$145 - \$157	\$140 - \$150		\$595 - \$615	\$575 - \$590	
Other Operating Expenses Net of Other Revenue ² (\$MM)	\$10 - \$20		\$2 - \$10	\$20 - \$30		\$25 - \$35
Transportation Expense (\$MM)	\$25 - \$30	\$15 - \$20		\$105 - \$115	\$65 - \$70	
Taxes Other Than on Income (\$MM)	\$65 - \$75	\$60 - \$65		\$275 - \$285	\$240 - \$250	
Interest and Debt Expense, Net (\$MM)	\$30 - \$35			\$125 - \$135		
Capital (\$MM)	\$110 - \$130	\$95 - \$110	\$12 - \$16	\$430 - \$470	\$410 - \$435	\$12 - \$20
Adj. EBITDAX ³ (\$MM)	\$240 - \$280	\$290 - \$325	\$(10) - \$(5)	\$970 - \$1,070	\$1,215 - \$1,305	\$(50) - \$(10)

Other Assumptions	1Q26E
Brent (\$/Bbl)	\$66.42
NYMEX (\$/Mcf)	\$5.22
Oil - % of Brent	94% - 98%
NGL - % of Brent	60% - 66%
Natural Gas - % of NYMEX	58% - 64%
Deferred Income Taxes ³	62% - 74%
Effective Tax Rate	~32%

2026E
\$65.57
\$4.13
94% - 98%
55% - 60%
65% - 70%
62% - 74%
~32%



Strong Balance Sheet, Ample Liquidity and Financial Flexibility

Ample Liquidity Coverage

Net Debt* Snapshot as of December 31, 2025 (\$MM)

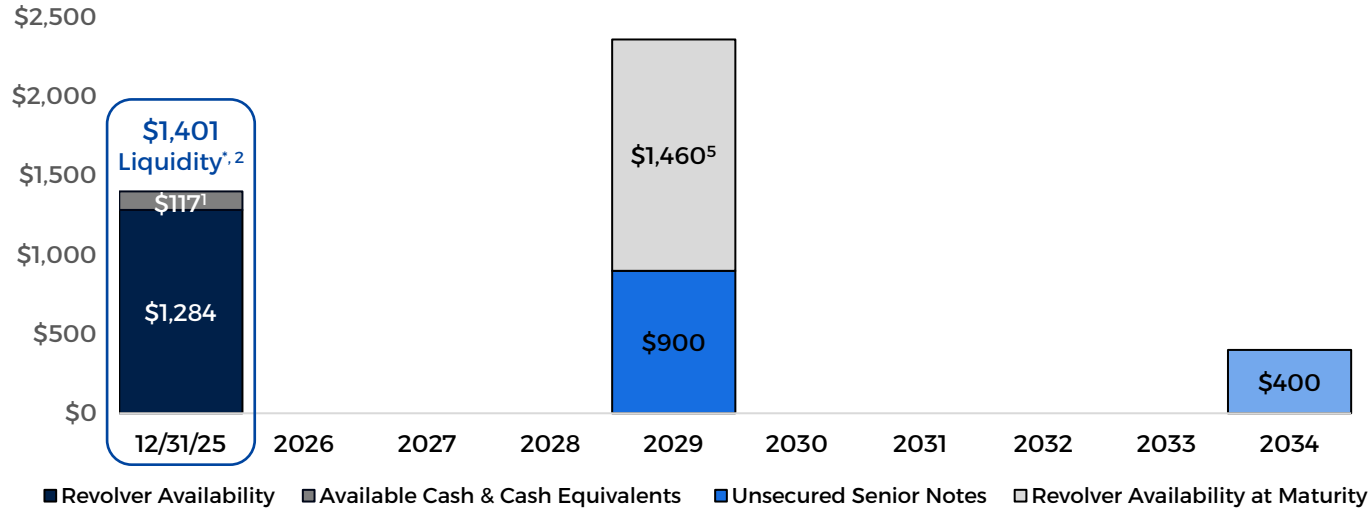
Revolving Credit Facility (RCF)	\$	-
8.250% 2029 Senior Notes		900
7.000% 2034 Senior Notes		400
Face Value of Debt	\$	1,300
Less Available Cash & Cash Equivalents ¹		(117)
Net Debt*	\$	1,183
Liquidity* ²	\$	1,401

Multiples Demonstrate Strength

	(\$MM)
RCF Borrowing Base	\$1,500
4Q25 Free Cash Flow*	\$115
4Q25 Net Debt* / LTM Adj. EBITDAX* ³	1.0x
LTM Adj. EBITDAX* / LTM Interest Expense* ⁴	11.7x

Long-Dated Maturities Provide Flexibility

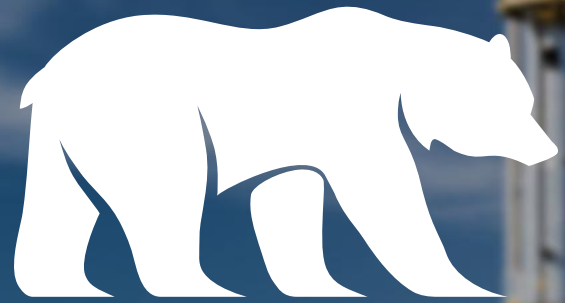
Debt Maturity Profile (\$MM)



2025 Highlights

- Issued \$400MM in 7.000% 2034 Senior Notes at par
- Redeemed outstanding 2026 Senior Notes
- Borrowing base reaffirmed at \$1.5B
- Elected commitments raised by \$310MM to \$1.46B

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

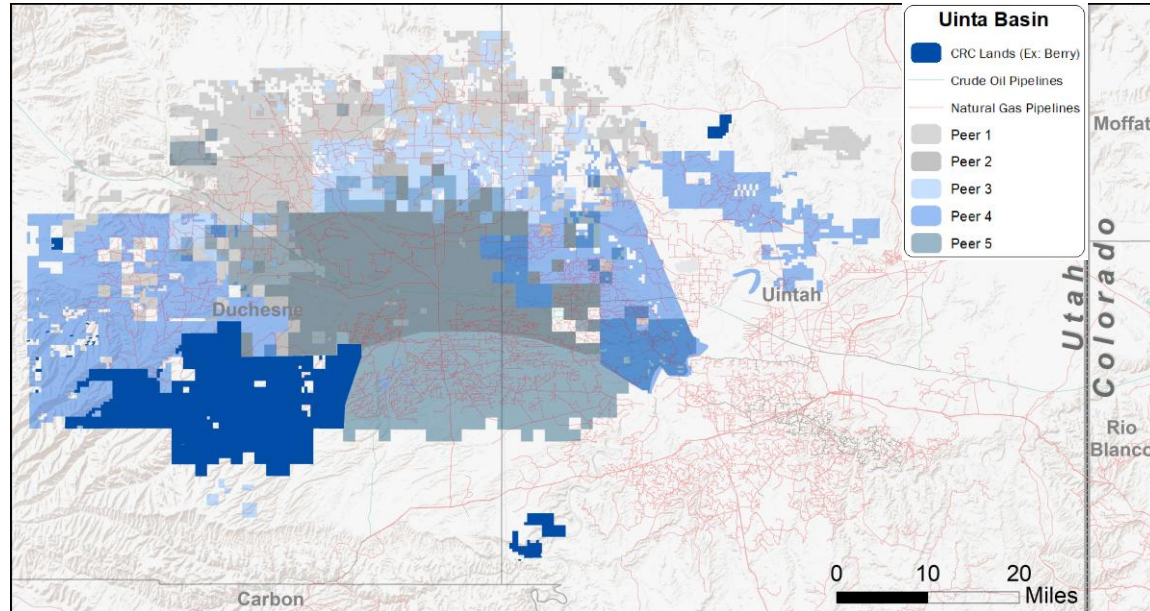


Appendix



Uinta Basin Development Upside

Strong Footprint in the Heart of the Uinta Basin



Historical
Development Growth

14%¹

YoY Production Growth



Low-Decline
Conventional Base

3.7MBoe/d²

2025; ~12% Annual Base Decline

Asset Overview

Net Mineral Acres	~98,455
Net Revenue Interest	~61%
2025 Production ¹	5.0MBoe/d
2025 Oil Production %	61%

- Uinta Basin is one of the last remaining stacked pay growth opportunities in the L48
 - Multi-bench development: Douglas Creek, Castle Peak, Uteland Butte and Wasatch
- Advantaged cost and return profile from existing infrastructure and advantaged position in the basin
- High working interest and held-by-production acreage allows for optimized development
- Farm-in Wells: Low-cost investment opportunities to delineate and gather data from adjacent acreage
- Operated Wells: First HZ pad (4 wells) drilled in 2025 applied learnings from prior farm-ins and operational execution
 - January 2026 pad net production: ~1.7 MBoe/d
 - Peak pad 30-day gross production: ~4.0 MBoe/d

On Track for California's First CO₂ Injection



First injection – Spring 2026, subject to EPA approval

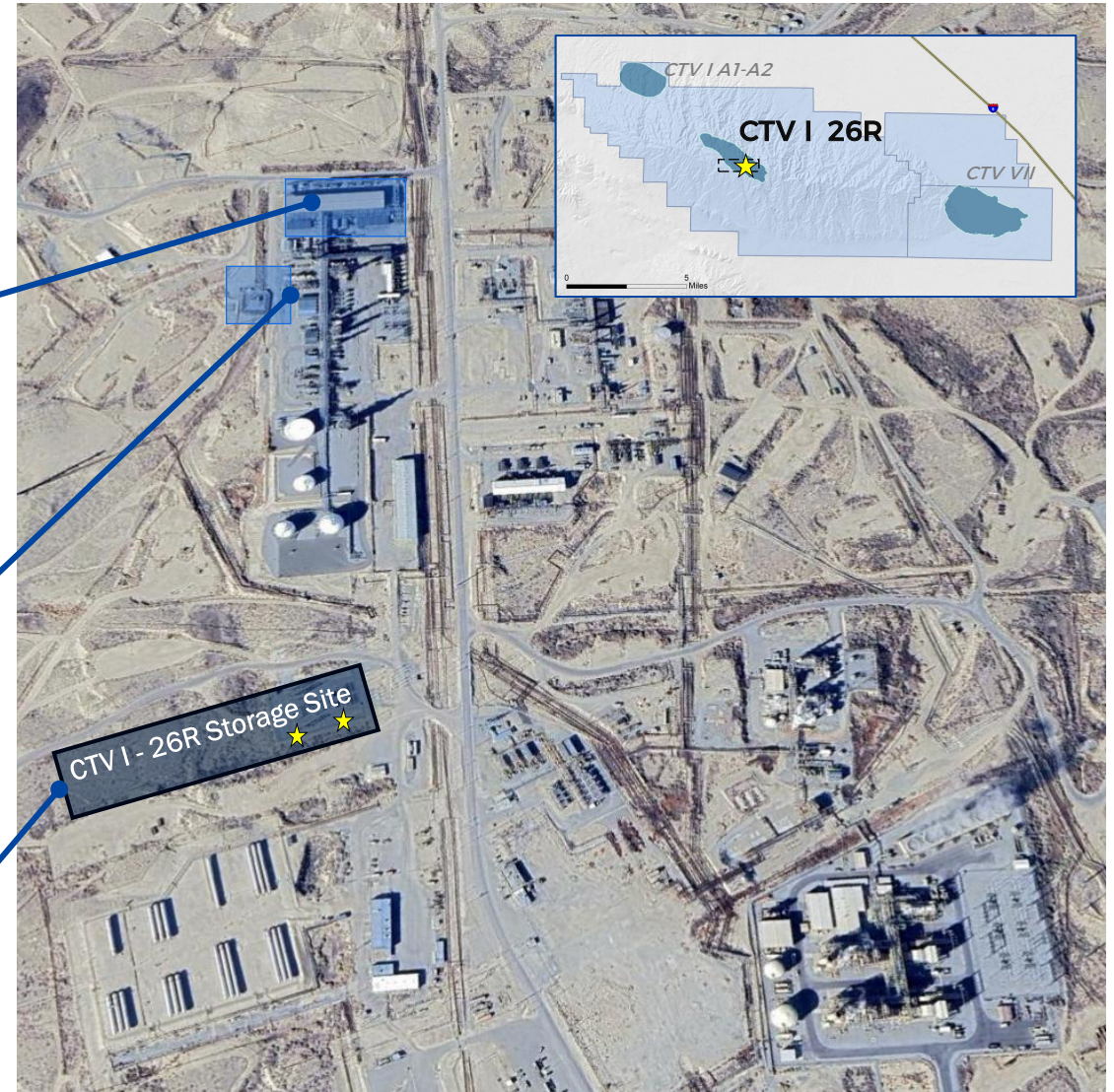
CO₂ Capture and Compression



CO₂ Emitter Pad and Pipeline



Injection Pad



On Track for California's First CO₂ Injection (cont.)

CO₂ Compression and Dehydration

- 2x Compressor Redesign and Isolation from Ethane Service
- TEG Dehydration Package
- Dedicated CO₂ Lube Oil System

Stripping CO₂ from Gas

- Contactor Tower
- Gas Filtration and Conditioning

Field Gas Inlet Conditioning and CGPI Inlet

- Evaporative Cooler
- Liquid Knock Out Vessel
- Dual Large Bore Pipelines

Large Bore Inner Plant Piping

- Amine Inlet and Outlet
- Hot Oil Loop

CO₂ Discharge and Blow Down Systems

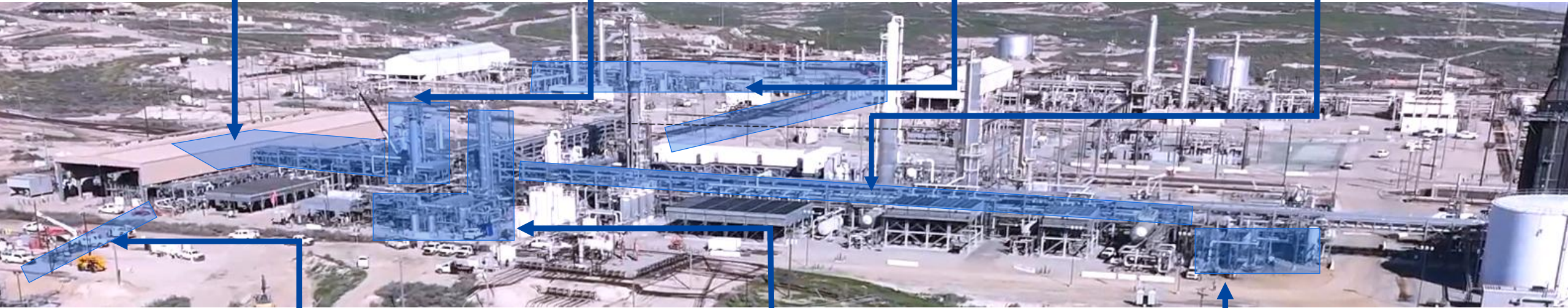
- High Pressure CO₂ Discharge
- High Pressure Blow down and Vent Stack
- Low Pressure Blow down, Liquid Vessel, and Vent Stack

Amine Regeneration

- Regeneration Tower
- Reclamation Package
- Lean and Rich Amine Filters

Amine Process Inlet

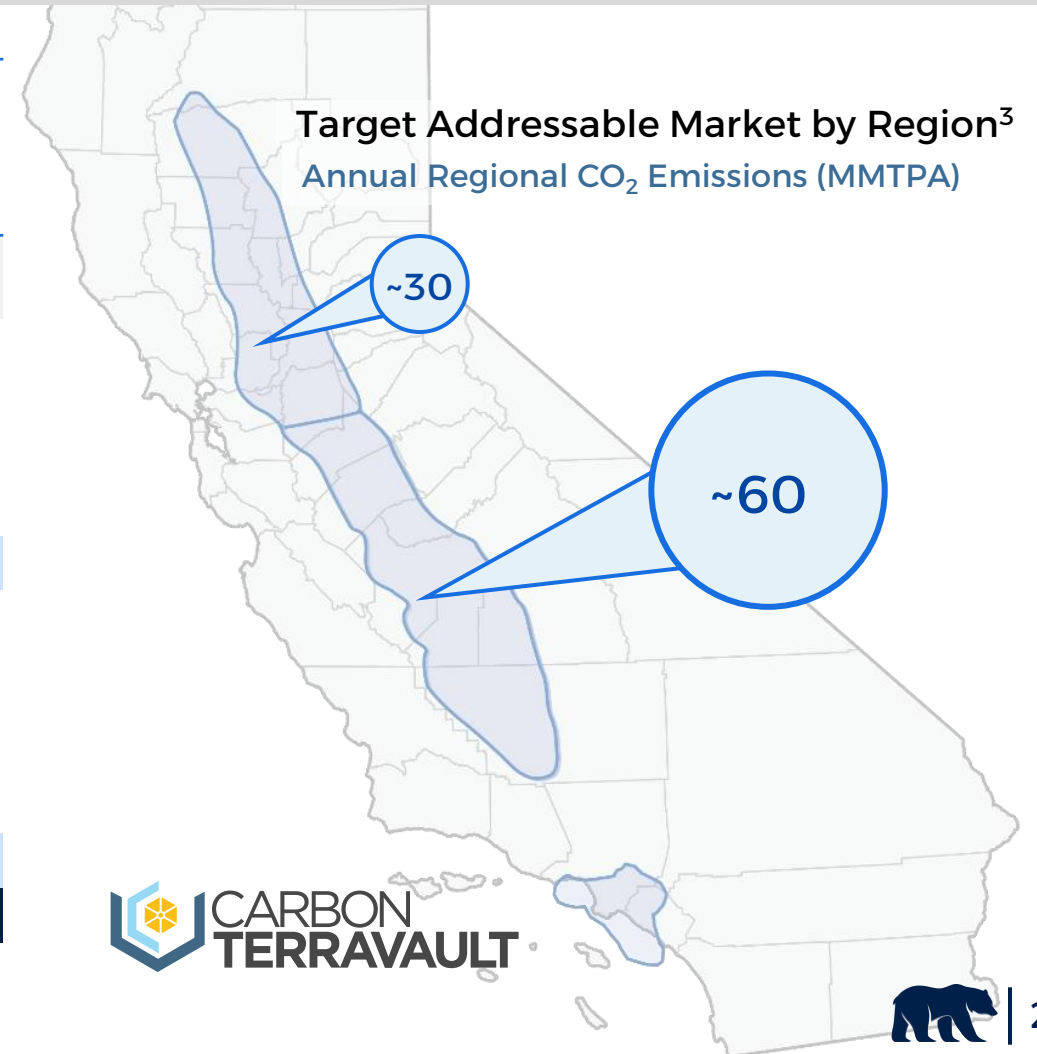
- Gas/Gas Heat Exchanger
- Inlet and Outlet liquid Separation



California's Premier Carbon Management Provider

- Anticipating first CO₂ injection at California's first CCS project in Spring 2026, subject to EPA approval
- Anticipating the receipt of Class VI draft permits for additional reservoirs in 2026¹

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
CTV I A1-A2	2026	~0.8	~0.4	~0.2	~8
Carbon Frontier	2026	~3.3	~1.6	~0.8	~32
CTV VI	2027	~3.4	~5.1	~2.5	~102
CTV VII (NEW)	-	~1.4	~1.4	~0.7	~27
Central California		~10.4	~10.4	~5.2	~207
CTV II	2026	~1.0	~1.2	~0.6	~23
CTV III	2026	~2.5	~3.6	~1.8	~71
CTV IV	2026	~1.4	~1.7	~0.9	~34
CTV V	2026	~0.7	~0.8	~0.4	~17
Northern California		~5.6	~7.3	~3.7	~145
Total - Combined		~16.0	~17.7	~8.9	~352



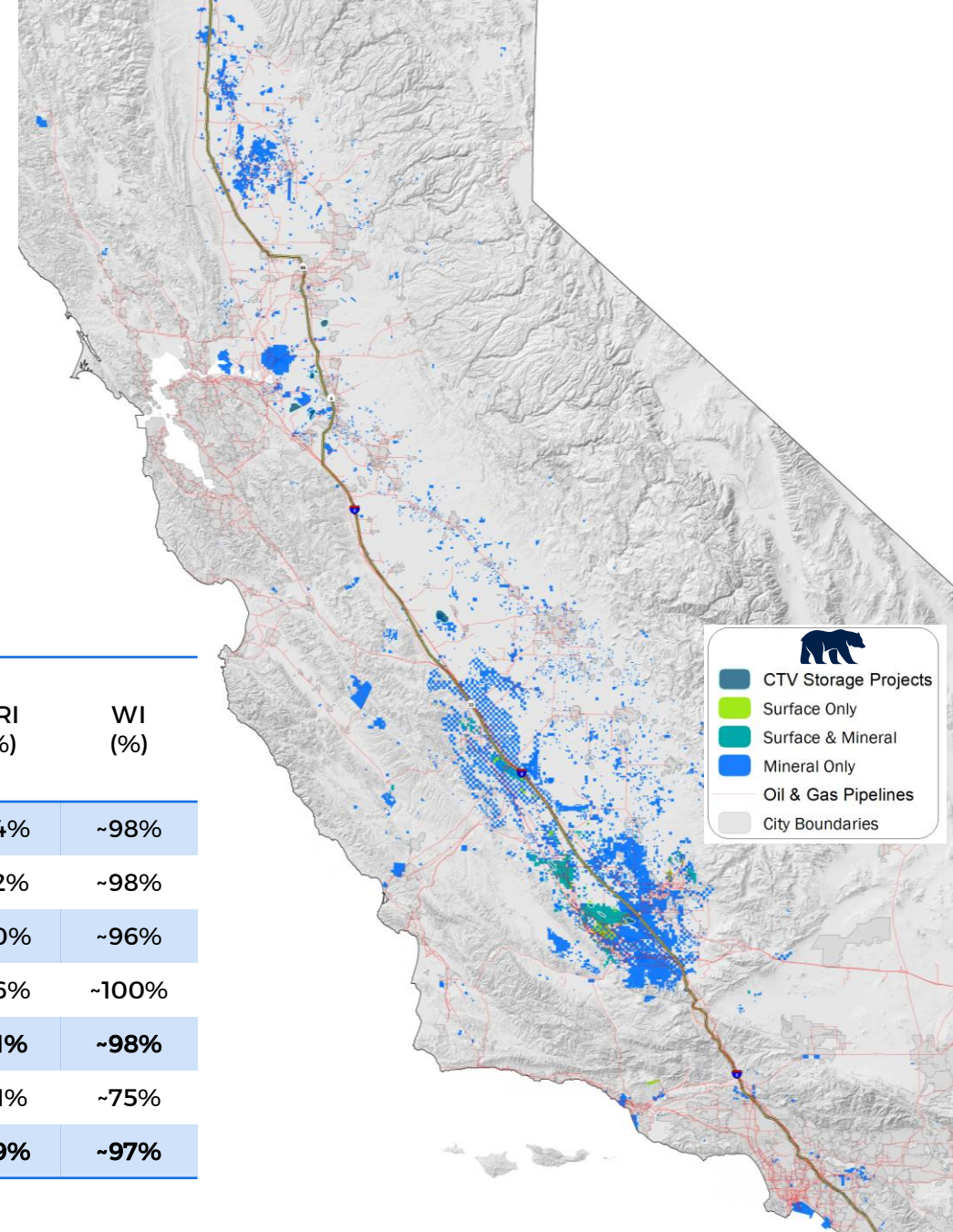
Premier California Energy Company

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 Inventory¹

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%



Hedge Portfolio *(as of December 31, 2025)*

OIL		1Q26E	2Q26E	3Q26E	4Q26E	2027E	2028E
SOLD CALLS							
Brent	Barrels per Day	37,078	36,000	36,000	36,000	2,465	1,534
	Weighted-Average Price	\$83.45	\$83.51	\$83.51	\$83.51	\$71.06	\$70.59
SWAPS							
Brent	Barrels per Day	51,861	44,487	42,869	41,703	50,110	7,285
	Weighted-Average Price	\$69.25	\$68.52	\$68.20	\$67.98	\$65.76	\$66.98
PURCHASED PUTS ¹							
Brent	Barrels per Day	37,078	36,000	36,000	36,000	2,465	1,534
	Weighted-Average Price	\$61.08	\$61.11	\$61.11	\$61.11	\$61.01	\$60.00
NATURAL GAS		1Q26E	2Q26E	3Q26E	4Q26E	2027E	2028E
SWAPS							
SoCal Border	MMBtu per Day	20,350	13,250	10,750	9,908	-	-
	Weighted-Average Price	\$5.18	\$4.82	\$4.83	\$4.84	\$-	\$-
NWPL Rockies ²	MMBtu per Day	91,750	91,750	91,750	91,750	71,861	1,576
	Weighted-Average Price	\$4.35	\$3.77	\$3.76	\$4.17	\$4.13	\$3.95
EST. HEDGE CONTRACT SETTLEMENTS ³		1Q26E	2Q26E	3Q26E	4Q26E	2027E	2028E
Combined Hedge Portfolio (\$MM)		\$23	\$15	\$22	\$23	\$75	\$13



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 2026E net oil production hedged with an average Brent floor price of ~\$65 per barrel⁴



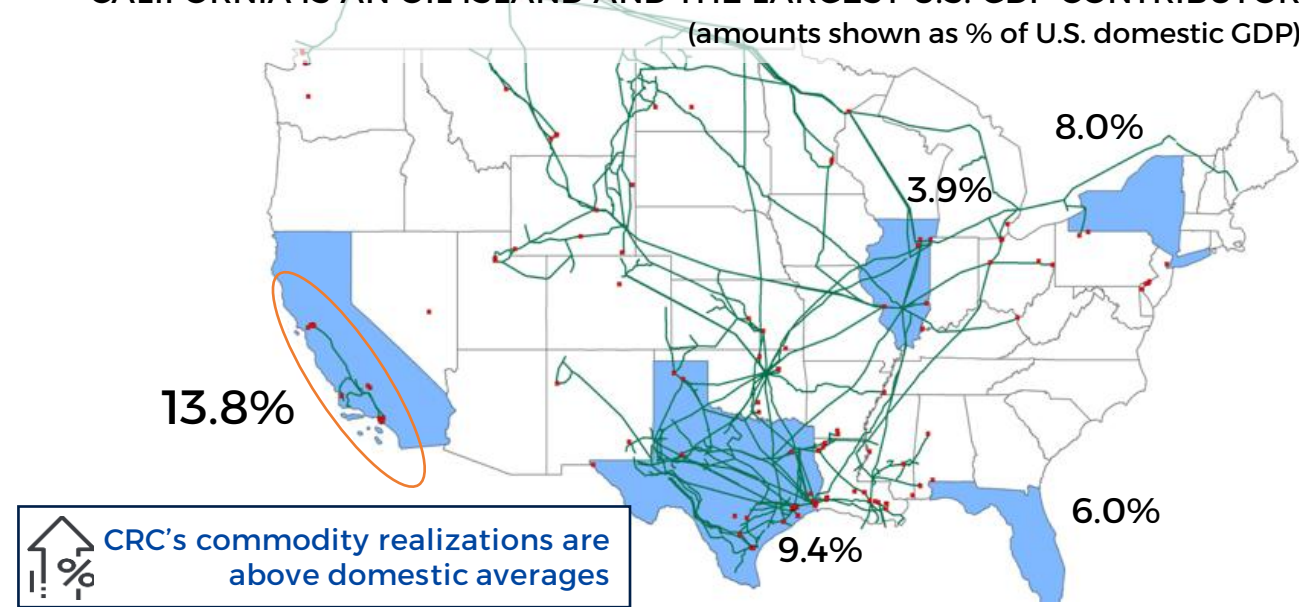
OPERATIONS

~66% of 2026E internal fuel consumption hedged at an average natural gas price of ~\$4.13 per MMBtu⁴

Strong Commodity Price Realizations

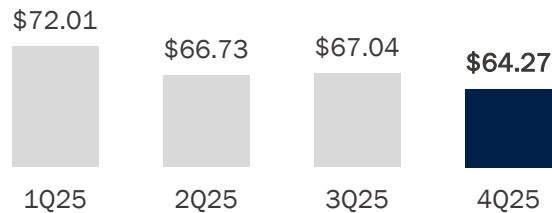
- **Crude:** 4Q25 Brent crude prices declined Q/Q and Y/Y as global supply growth from both OPEC+ and non-OPEC+ producers continued to exceed demand growth. California crude realizations remained stable, supported by sustained demand for in-state grades
- **Natural Gas:** 4Q25 North American natural gas prices experienced increased volatility, with early cold weather followed by a return to more historical seasonal conditions. California regional index prices increased Q/Q and Y/Y, despite ample storage inventories in California and across the Western US
- **NGLs:** 4Q25 NGL prices and realizations increased Q/Q due to seasonal demand, but declined Y/Y in line with lower crude prices. California NGLs continued to trade at a premium to broader North American markets

CALIFORNIA IS AN OIL ISLAND AND THE LARGEST U.S. GDP CONTRIBUTOR
(amounts shown as % of U.S. domestic GDP)



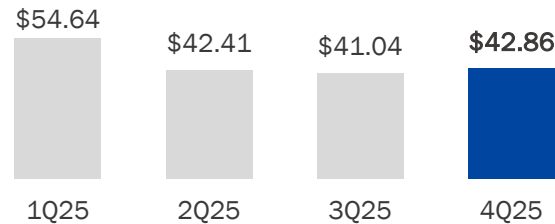
Note: 5 largest contributors to domestic GDP. Source: BEA, preliminary data for 3Q25; EIA

Oil w/ Hedges (\$/BBL)



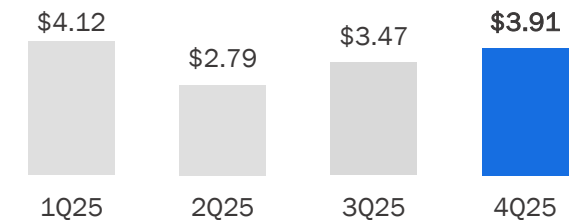
Average Benchmark Prices ¹	\$74.92	\$66.76	\$68.13	\$63.08
% of Benchmark ¹	98%	97%	97%	97%
Hedge Settlements	(\$1.56)	\$1.66	\$0.72	\$3.13
Average Realized Prices ²	\$72.01	\$66.73	\$67.04	\$64.27

NGLs (\$/BBL)



Average Benchmark Prices ¹	\$74.92	\$66.76	\$68.13	\$63.08
% of Benchmark ¹	73%	64%	60%	68%
Hedge Settlements	-	-	-	-
Average Realized Prices ²	\$54.64	\$42.41	\$41.04	\$42.86

Natural Gas (\$/MCF)



Average Benchmark Prices ¹	\$3.65	\$3.44	\$3.07	\$3.55
% of Benchmark ¹	113%	81%	113%	110%
Hedge Settlements	-	-	-	-
Average Realized Prices ²	\$4.12	\$2.79	\$3.47	\$3.91

Sustainability and Social Responsibility Are Core Priorities



2025 Sustainability Highlights

ENVIRONMENT

- Plugged and sealed >1,400 wells, ~120% of the legally required amount
- Eliminated 351 pneumatic venting devices, >450 MT of methane annually
- Delivered >108MM barrels of water for agricultural use, >3x internal freshwater consumption
- Published 2024 Sustainability report with a reframing around our Responsible Net Zero Goal and United Nations Sustainability Development Goals alignment
- Received an initial 'A' grade from MiQ for methane performance in the San Joaquin and Ventura basins
- Recertified MiQ 'A' grade for operations in Los Angeles basin
- Maintained California Office of Spill Response Certification for CRC's spill management team and is the only operator in California to receive this recognition
- Maintained Wildlife Habitat Council projects and nominated as a finalist for 'Best Invasive Species' management project at Bolsa Chica

SOCIAL

- >125 non-profits supported | Donated \$2MM to local California communities through CRC's community giving programs¹
- Qualified for 29 national safety awards for exceptional performance
- Maintained a TRIR² of 0.40 vs. 2024 BLS industry average of 0.50

GOVERNANCE

- Board is 22% gender diverse and 33% composed of members from underrepresented communities
- 25% of the 2025 executive compensation scorecard metrics relating to Company performance tied to ESG-related carbon management, environmental stewardship, and worker safety

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 <i>(a subsidiary of CRC)</i>
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 4:

- (1) Represents achievement of the highest annual adjusted EBITDAX, annual free cash flow and annual total shareholder returns which includes share repurchases and dividends paid since 2021.
- (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.
- (3) Represents MiQ methane emissions performance standard 'Grade A' certifications for operations in the San Joaquin, Ventura and Los Angeles basins.

Slide 5:

- (1) Total year 2026E guidance assumes a 2026E Brent price of \$65.57 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of \$4.13 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 17 for 2026E guidance.
- (2) Subject to commodity prices and market factors.
- (3) Assumes the midpoint of 2026E net production guidance. See slide 17 for 2026E guidance.
- (4) Source: EPA as of February 13, 2026, www.epa.gov/uic/class-vi-wells-permitted-epa.

Slide 6:

- (1) Proved developed (PD) reserves include proved developed producing (PDP) and proved developed non-producing (PDNP) reserves.
- (2) Proved reserves estimated as of December 31, 2023, 2024 and 2025 using SEC Prices of \$82.84, \$80.42 and \$69.38 per barrel for oil, and \$2.64, \$2.13 and \$3.39 per MMBtu for natural gas, respectively.
- (3) Source: Enverus as of February 12, 2026. Data represents the peer average estimated next twelve-month base oil production decline rates as of 3Q25. Peer group includes APA, BKV, CHRD, CRK, CRGY, GPOR, KOS, MGY, MTD, MUR, NOG, RRC, SM, TALO and VET. MUR reflects onshore operations only and VET reflects Canada operations only.
- (4) Reserve replacement ratio is calculated as total reserves added during the period divided by total production for the same period, and excludes revisions related to price.
- (5) Source: CRC internal estimates.

Slide 7:

- 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.
- PV-10 is a non-GAAP financial measure. GAAP prescribes a standardized measure of discounted future net cash flows only for proved reserves using SEC pricing. For a reconciliation of PV-10 of proved reserves using SEC prices to the standardized measure, please refer to CRC's Form 10-K for the fiscal year ended December 31, 2025. A comparable GAAP measure does not exist for probable reserves or for proved reserves on a basis other than SEC pricing. Accordingly, no reconciliation of PV-10 of probable reserves has been provided for those items.

Assumptions, Estimates and Endnotes

Slide 7 (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, CHRDR, 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 \$1,183MM (as of December 31, 2025) plus market capitalization (as of February 27, 2026) using 88.6MM 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 (\$10.3B) and probable (\$6.9B) reserves as of December 31, 2025 was 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. 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, 2024.

Slide 8:

- (1) Total year 2026E guidance assumes a 2026E Brent price of \$65.57 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of \$4.13 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 17 for 2026E guidance.

Slide 9:

- (1) Total year 2026E guidance assumes a 2026E Brent price of \$65.57 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of \$4.13 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 17 for 2026E guidance.
- (2) Source: CRC internal estimates. Program economics reflect available inventory supported by permits in hand.
- (3) Multiple on Invested Capital (MOIC) refers to the total value generated by a drilling program relative to the capital originally invested in it, calculated by dividing total returns by the initial capital deployed.
- (4) Breakeven price represents the average crude oil price at which CRC's projected cumulative 2026E cash flow from operations (before net changes in operating assets and liabilities) equals projected capital expenditures and dividends, and includes project synergies and cost reductions. The analysis assumes the midpoints of 2026E guidance (see slide 17 for 2026E guidance). For purposes of the O&G-only breakeven calculation, the capital program excludes carbon management capital, and projected cash flows exclude contributions from carbon management activities, power operations and corporate. The analysis includes the impact of hedges as of December 31, 2025. Brent crude oil is assumed to be priced at a \$4/bbl premium to WTI. All future quarterly dividends and share repurchases remain subject to debt agreement covenants and approval by the Board of Directors.
- (5) Other includes C&J Well Services and exploration capital.

Assumptions, Estimates and Endnotes

Slide 10:

- (1) MOUs and CDMA's 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.
- (2) Total year 2026E guidance assumes a 2026E Brent price of \$65.57 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of \$4.13 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 17 for 2026E guidance.
- (3) Based on internal estimates of total resources located in California, and includes resources not owned by CRC.

Slide 11:

- (1) Source: 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.

Slide 13:

- (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.

Slide 14:

- (1) Breakeven price represents the average crude oil price at which CRC's projected cumulative 2026E-2028E cash flow from operations (before net changes in operating assets and liabilities) equals projected capital and dividends, and includes projected synergies and cost reductions. Maintenance capital reflects the D&C and Workover capital required to maintain flat year-over-year production, excluding growth capital. For purposes of the O&G-only breakeven calculation, the capital program excludes carbon management capital, and projected cash flows exclude contributions from carbon management activities, power operations and corporate. The analysis assumes the midpoint of 2026E commodity and capital guidance of \$65.57 Brent and \$450MM (see slide 17), respectively, and a steady-state maintenance capital program beginning in 2027 of approximately seven operated rigs (~\$405MM), workovers (~\$80MM), facilities (~\$80MM), carbon management (~\$20MM), and corporate and other capital (~\$10-15MM), totaling approximately \$600MM annually. The analysis further assumes constant Brent prices of \$60, \$65, \$70, and \$75 in 2027 and 2028 across the respective scenarios. Additional assumptions include an average NYMEX natural gas price of \$3.69/Mcf across all cases, Brent crude oil priced at a \$4/bbl premium to WTI, dividends held flat relative to the 2026 level, production remaining flat beginning January 2027, average annual electricity margin of \$40-60MM, average annual purchased commodities margin of \$30-50MM, and the impact of hedges as of December 31, 2025. The analysis excludes growth capital, acquisitions, divestitures, discretionary expansion projects, and interest expense. All future quarterly dividends remain subject to debt agreement covenants and approval by the Board of Directors.

Slide 16:

- (1) 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.
- (2) 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
- (3) Electricity margin is calculated as the difference between electricity sales and electricity generation expenses.
- (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) Represents achievement of the highest annual adjusted EBITDAX, annual free cash flow and annual total shareholder returns which includes share repurchases and dividends paid since 2021.



Assumptions, Estimates and Endnotes

Slide 17:

- (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) 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.
- (3) Deferred income taxes is calculated as deferred taxes divided the total income tax provision for the period.
- (4) Corporate and other includes corporate, C&J Well Services and exploration capital.

Slide 18:

- (1) Available cash and cash equivalents excludes \$15MM of restricted cash.
- (2) Liquidity on December 31, 2025 is calculated as \$117MM of cash and cash equivalents (excluding \$15MM of restricted cash) plus \$1,460MM of borrowing capacity on CRC's Revolving Credit Facility less \$176MM in outstanding letters of credit.
- (3) Net leverage is calculated as 4Q25 net debt of \$1,183MM (excluding restricted cash of \$15MM) divided by LTM adjusted EBITDAX of \$1,241MM.
- (4) Interest coverage is calculated as LTM adjusted EBITDAX of \$1,241MM and LTM interest expense of \$106MM.
- (5) Undrawn Revolving Credit Facility as of December 31, 2025, excluding outstanding letters of credit.

Slide 20:

- (1) 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. Fourth quarter 2025 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.
- (2) Uinta Basin production for the first nine months of 2025 is derived from Berry Corporation's publicly reported data prior to its merger with California Resources Corporation. Fourth quarter 2025 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 23:

- (1) Source: EPA as of February 13, 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) 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 24:

- (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. Fourth quarter 2025 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.

Assumptions, Estimates and Endnotes

Slide 25:

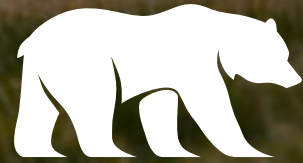
- (1) Purchased and sold puts with the same strike price have been netted together.
- (2) NPWL volumes require transportation to where the gas is consumed. These costs are reflected in our 2026E transportation guidance. See slide 17 for 2026E guidance.
- (3) Represents estimated net cash settlement payments inclusive of premiums for derivative contracts and forward commodity prices as of December 31, 2025.
- (4) Subject to commodity prices and market factors.

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 natural gas.

Slide 27:

- (1) Contributions for the full 2025 calendar year exclude donations made by Berry Corporation, which merged with CRC in December 2025.
- (2) Total Recordable Incident Rate (TRIR) calculated as recordable incidents per 200,000 hours for all workers (employees and contractors).



CALIFORNIA
RESOURCES

A DIFFERENT **KIND** OF ENERGY COMPANY

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