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

# Investor Presentation

June 2022

CALIFORNIA RESOURCES CORPORATION COMPANY | CARBON TERRAVAULT

# Forward Looking / Cautionary Statements – Certain Terms

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

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

- fluctuations in commodity prices and the potential for sustained low oil, natural gas and natural gas liquids prices;
- legislative or regulatory changes, including those related to (i) drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, (ii) managing energy, water, land, greenhouse gases (GHGs) or other emissions, (iii) protection of health, safety and the environment, (iv) tax credits or other incentives, or (v) transportation, marketing and sale of our products;
- availability or timing of, or conditions imposed on, permits and approvals necessary for drilling or development projects;
- changes in business strategy and our capital plan;
- lower-than-expected production, reserves or resources from development projects or acquisitions, or higher-than-expected decline rates;
- incorrect estimates of reserves and related future cash flows and the inability to replace reserves;
- the recoverability of resources and unexpected geologic conditions;
- our ability to realize the benefits of business strategies and initiatives related to energy transition, including carbon capture and storage projects and other renewable energy efforts;
- our ability to finance and implement our carbon capture and storage projects;
- global geopolitical, socio-demographic and economic trends and technological innovations;
- changes in our dividend policy and our ability to declare future dividends;
- production-sharing contracts' effects on production and operating costs;
- limitations on our financial flexibility due to existing and future debt;
- insufficient cash flow to fund planned investments, interest payments on our debt, stock repurchases or changes to our capital plan;
- insufficient capital or liquidity unavailability of capital markets or inability to attract potential investors;
- limitations on transportation or storage capacity and the need to shut-in wells;
- inability to enter into desirable transactions, including acquisitions, asset sales and joint ventures;
- joint ventures and acquisitions and our ability to achieve expected synergies;
- our ability to utilize our net operating loss carryforwards to reduce our income tax obligations;
- our ability to successfully gather and verify data regarding emissions, our environmental impacts and other initiatives;
- the compliance of various third parties with our policies and procedures and legal requirements as well as contracts we enter into in connection with our climate-related initiatives;
- the effect of our stock price on costs associated with incentive compensation;
- changes in the intensity of competition in the oil and gas industry;
- effects of hedging transactions;
- equipment, service or labor price inflation or unavailability;
- climate-related conditions and weather events;
- disruptions due to accidents, mechanical failures, power outages, transportation or storage constraints, natural disasters, labor difficulties, cyber-attacks or other catastrophic events;
- pandemics, epidemics, outbreaks, or other public health events, such as the COVID-19; and
- other factors discussed in Part I, Item 1A - Risk Factors in CRC’s Annual Report on Form 10-K and our other SEC filings available at www.crc.com.

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

# Glossary

| Term | Definition |
|---|---|
| API | American Petroleum Institute Gravity |
| BMT | Billion Metric Tons |
| BOD | Board of Directors |
| BTM | Behind the Meter |
| C | Celsius |
| C&T | Cap and Trade |
| CARB | California Air Resources Board |
| CATF | Clean Air Task Force |
| CCS | Carbon Capture and Storage |
| CCUS | Carbon Capture, Utilization and Storage |
| CGP | Cryogenic Gas Plant |
| CI | Carbon Intensity |
| CMB | Carbon Management Business |
| $CO_2$ | Carbon Dioxide |
| CTV | Carbon TerraVault |
| CUP | Conditional Use Permit |
| D&C | Drilling and Completions |
| DAC | Direct Air Capture |
| DOE | Department of Energy |
| DCF | Discretionary Cash Flow |
| E&P | Exploration and Production |
| EIR | Environmental Impact Report |
| EOR | Enhanced Oil Recovery |

| Term | Definition |
|---|---|
| EPA | Environmental Protection Agency |
| EPCC | Engineering, Procurement, Construction and Commissioning |
| ESG | Environmental, Social and Governance |
| FCF | Free Cash Flow |
| FEED | Front End Engineering and Design |
| FID | Final Investment Decision |
| FTM | Front of the Meter |
| GHG | Greenhouse Gas |
| LCFS | Low Carbon Fuel Standard |
| LOI | Letter Of Intent |
| MMT | Million Metric Tons |
| MMTPA | Million Metric Tons Per Annum |
| MPa | Megapascal Pressure Unit |
| MRV | Monitoring, Reporting and Verification Plan |
| MT | Metric Tons |
| MTPA | Metric Tons Per Annum |
| MW | Megawatts |
| NATCARB | National Carbon Sequestration Database and Geographical Information System |
| NTP | Notice To Proceed |
| O&G | Oil and Gas |
| RNG | Renewable Natural Gas |
| SRP | Share Repurchase Program |

# 1Q22 Key Takeaways

GENERATED

**$206 MM** OF Adj. EBITDAX[1] & **$61 MM** OF FREE CASH FLOW[1]

Expanding the drilling program by adding one more rig in the Los Angeles Basin & raising 2022 oil production guidance by 1 MBO/D

Raising Free Cash Flow[1] guidance by 17% to $330 - $410 MM range

CTV Update: Applied for **2 new Class VI permits for an additional 80 MMT of $CO_2$ storage** while continuing discussions with ~20 MMTPA of emitters, targeting YE2022 for selection of the first 1 MMTPA emitter contract

CalCapture CCS+ Update: Announced a **new FEED study with Next Carbon Solutions**

Shareholder Returns Update: **Increasing SRP by $300 MM** to $650 MM and extending through 2Q23; CRC repurchased ~$91 MM worth of shares YTD[2] at an average price of $42.87 per share


## Additional Highlights

Issued Updated & Improved ESG Goals

Increased 2022 Guidance

Safely Completed & Ahead of Schedule CGP1 Maintenance

(1) Free Cash Flow and Adj. EBITDAX are non-GAAP measures. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. (2) Includes repurchases made from January 1, 2022, to April 29, 2022.

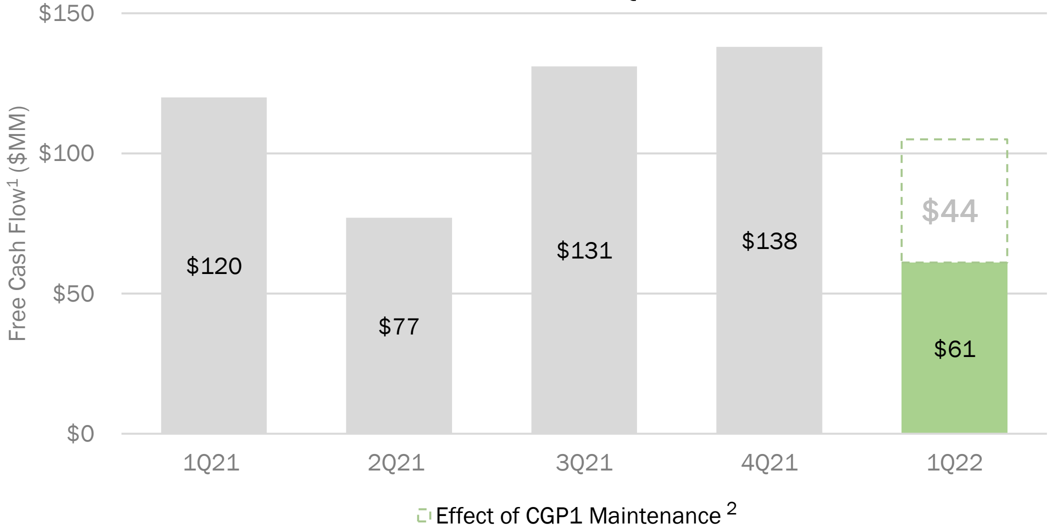
# Operational Results

# First Quarter 2022 Corporate Earnings

**Scheduled maintenance at CGP1 had a ~$44 MM negative impact on Free Cash Flow[1]**

| | 1Q21 | 2Q21 | 3Q21 | 4Q21 | 1Q22 |
|---|---|---|---|---|---|
| Adjusted Net Income[1] per Share – Diluted ($/share) | $1.22 | $0.94 | $1.83 | $2.13 | **$1.13** |
| **Adjusted EBITDAX[1] ($MM)** | $189 | $169 | $242 | $260 | **$206** |
| Cash Provided by Operating Activities ($MM) | $147 | $127 | $182 | $204 | **$160** |
| Capital Investments ($MM) | $27 | $50 | $51 | $66 | **$99** |
| **Free Cash Flow[1] ($MM)** | $120 | $77 | $131 | $138 | **$61** |

**GENERATED AN AGGREGATE OF $530 MM OF FREE CASH FLOW[1] OVER 5 QUARTERS**




**1Q22 Capital includes CGP1 maintenance & full operational quarter with 4 active rigs**

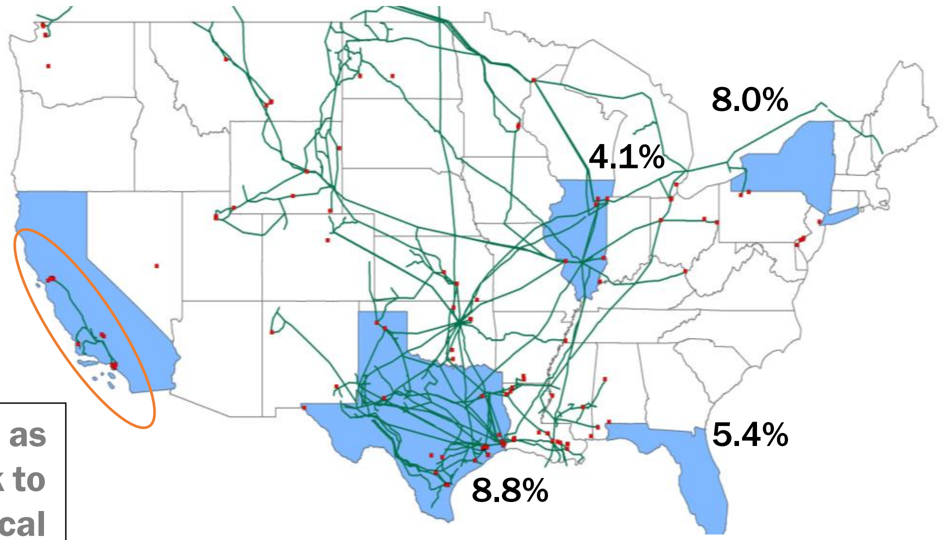
(1) Free Cash Flow, Adj. Net Income and Adj. EBITDAX are non-GAAP measures. For all historical non-GAAP financial measures, please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. (2) Lost free cash flow due to lost revenues from NGL and natural gas production due to CGP1 downtime as well as maintenance capital for CGP1.

# Strong Price Realizations in CA's Improving Market Dynamics

- **Crude:** CRC's Q1 '22 physical crude realizations remained strong, supported largely by moves in global crude pricing. Physical differentials to Brent lagged slightly due to planned and unplanned refinery maintenance in the state and competing waterborne alternatives. The basis for crude oil contracts in California is an average of in-State posted prices which have historically correlated closely with Brent crude prices.
- **NGLs:** NGL % realizations relative to crude declined in Q1 '22 relative to Q4 '21 as NGL prices declined slightly and crude prices increased. Declines in NGL prices stemmed from a milder-than-normal winter across California and the Northern Hemisphere as a whole, as well increased North American NGL production.
- **Natural Gas:** California natural gas prices for Q1 '22 started strong then slid across the quarter. January '22 prices peaked on expectations for extreme cold temperatures across the Western US and fears of a repeat of February '21's Winter Storm Uri. The winter storm failed to materialize, and prices drifted lower as a milder-than-normal winter persisted and high storage inventories on the SoCalGas system pressured prices across the quarter.

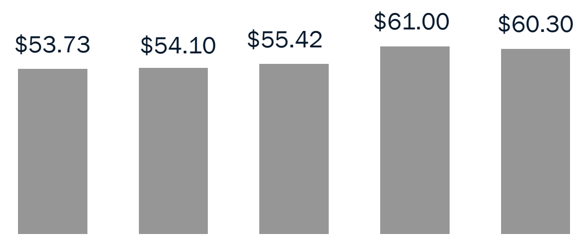
**Expecting NGL pricing as percentage of benchmark to return to long term historical levels for the remainder of 2022**

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



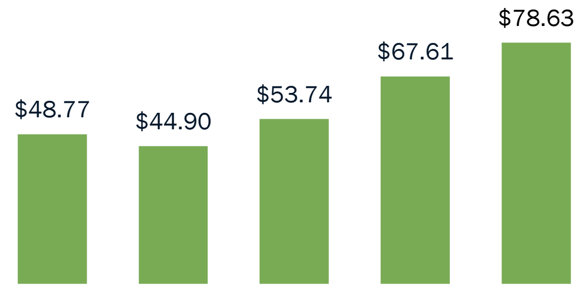

Note: 5 largest contributors to domestic GDP. Source: BEA, Data from 4Q21; EIA

### Oil w/ Hedges ($/BBL)



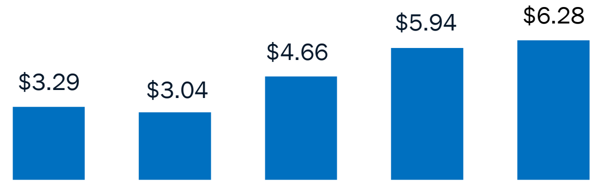

| | 1Q21 | 2Q21 | 3Q21 | 4Q21 | 1Q22 |
|---|---|---|---|---|---|
| Average Benchmark Prices[1] | $61.10 | $69.02 | $73.23 | $79.80 | $97.38 |
| % of Benchmark[1] | 100% | 100% | 100% | 99% | 99% |
| Hedge Settlements | ($7.08) | ($14.84) | ($17.47) | ($17.99) | ($35.83) |
| Average Realized Prices | $53.73 | $54.10 | $55.42 | $61.00 | $60.30 |

### NGLs ($/BBL)




| | 1Q21 | 2Q21 | 3Q21 | 4Q21 | 1Q22 |
|---|---|---|---|---|---|
| Average Benchmark Prices[1] | $61.10 | $69.02 | $73.23 | $79.80 | $97.38 |
| % of Benchmark[1] | 80% | 65% | 73% | 85% | 81% |
| Hedge Settlements | – | – | – | – | – |
| Average Realized Prices | $48.77 | $44.90 | $53.74 | $67.61 | $78.63 |

### Natural Gas ($/MCF)

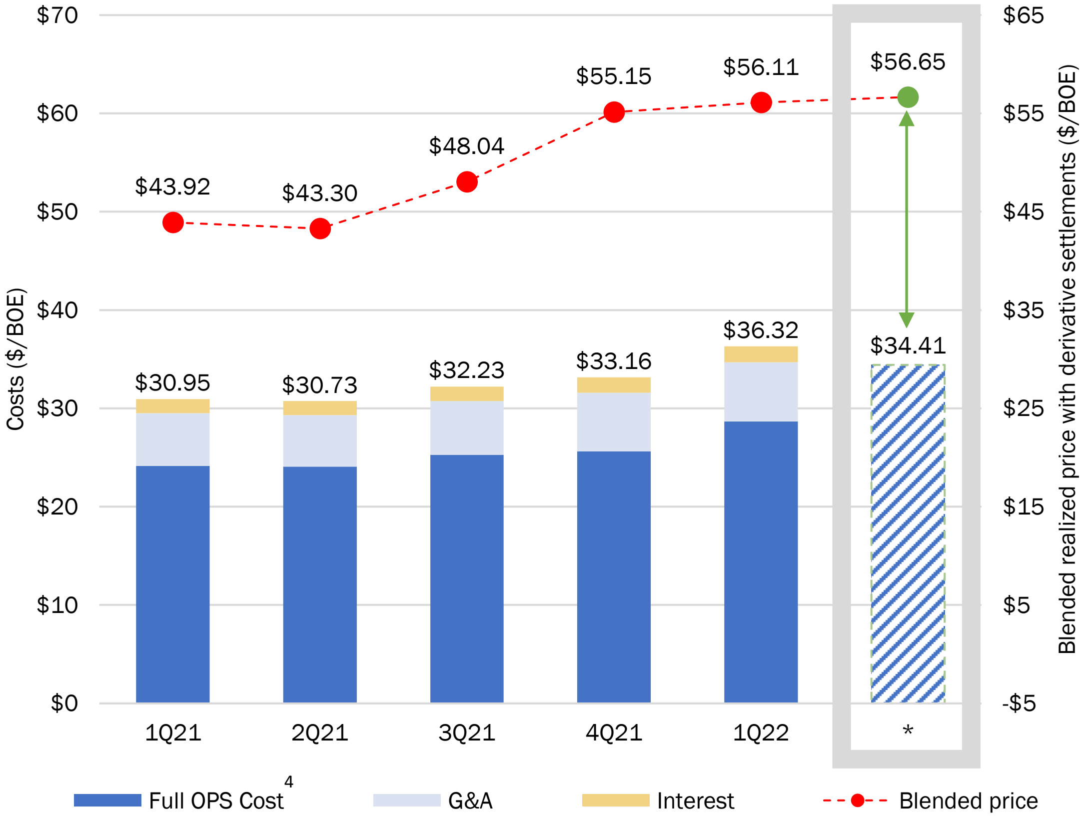



| | 1Q21 | 2Q21 | 3Q21 | 4Q21 | 1Q22 |
|---|---|---|---|---|---|
| Average Benchmark Prices[1] | $2.72 | $2.76 | $3.71 | $5.27 | $4.19 |
| % of Benchmark[1] | 121% | 110% | 126% | 113% | 150% |
| Hedge Settlements | – | – | – | – | – |
| Average Realized Prices | $3.29 | $3.04 | $4.66 | $5.94 | $6.28 |

(1) Benchmark prices are based on Brent for oil and NGLs and NYMEX average daily price for natural gas.

# Focus on Cost Management

**CRC'S 1Q22 COSTS & BLENDED REALIZED PRICE NEGATIVELY IMPACTED BY CGP1 MAINTENANCE**




* *$1.91 per BOE negative impact to costs due to CGP1 maintenance + negative impact to blended realized price of $0.54 per BOE due to lost NGLs and NG volumes*

**$1.21/BOE**

**increase in operating costs due to lost production from CGP1 maintenance**

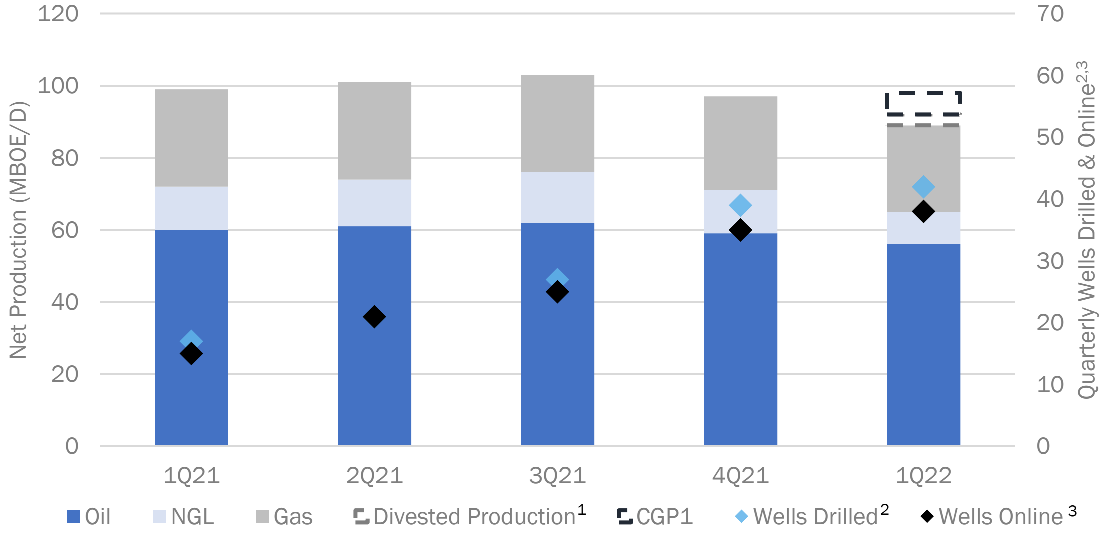
| | 1Q21 | 2Q21 | 3Q21 | 4Q21 | 1Q22 |
|---|---|---|---|---|---|
| Energy operating costs[1] ($/BOE) | $4.70 | $4.70 | $5.49 | $5.47 | $6.68 |
| Gas processing costs ($/BOE) | $0.53 | $0.66 | $0.56 | $0.41 | $0.56 |
| Non-energy operating costs[1,2] ($/BOE) | $13.10 | $13.12 | $14.23 | $14.57 | $15.63 |
| **Operating costs ($/BOE)** | **$18.33** | **$18.48** | **$20.28** | **$20.45** | **$22.87** |
| Costs attributable to PSC-type contracts[3] ($/BOE) | ($1.61) | ($1.73) | ($1.84) | ($2.13) | ($2.30) |
| **Operating costs** excluding effects of PSC-type contracts[3] ($/BOE) | **$16.72** | **$16.75** | **$18.44** | **$18.32** | **$20.57** |
| Transportation + Taxes other than on income ($/BOE) | $5.81 | $5.58 | $5.02 | $5.18 | $5.79 |
| G&A ($/BOE) | $5.36 | $5.25 | $5.44 | $5.96 | $6.03 |
| Interest and debt expense, net ($/BOE) | $1.45 | $1.42 | $1.49 | $1.57 | $1.63 |

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

(1) Energy operating costs consist of purchases of natural gas used to generate electricity, purchased electricity and internal costs to produce electricity used in our operations. Non-energy operating costs equal total operating costs less energy operating costs and gas processing costs. However, non-energy operating costs include the costs of purchasing natural gas used to generate steam for our steamfloods. (2) Non-energy operating costs includes costs of $1.45, $1.31, $2.35, 2.57 and $2.48 per BOE related to natural gas that is used to heat water for enhanced oil recovery in our steamflood operations for 1Q21, 2Q21, 3Q21, 4Q21 and 1Q22, respectively. (3) Represent non-GAAP measures. For all historical non-GAAP financial measures, please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. (4) Full OPS cost includes operating costs plus transportation costs, plus taxes other than on income.

# Continued Operational Excellence

## MAINTAINING NET OVERALL AND OIL PRODUCTION WITH LIMITED DRILLING & COMPLETION ACTIVITY




## 1Q22 DEVELOPMENT PERFORMANCE:

| San Joaquin Basin | |
|---|---|
| Rigs | 3 |
| Wells Drilled & Online[3] | 31 |
| TMD (ft.) | 4,685 |
| Peak IP[4] (BOE/D) | 59 |
| Estimated IRR[5] (%) | 117% |

| Los Angeles Basin | |
|---|---|
| Rigs | 1 |
| Wells Drilled & Online[3] | 7 |
| TMD (ft.) | 5,750 |
| Peak IP[4] (BOE/D) | 107 |
| Estimated IRR[5] (%) | 202% |

- 95% of our 1Q drilling projects were focused on high value, high margin horizontals
- Improved drilling efficiency by optimizing well design
- Autonomous inflow control device (AICD) implementation has shown positive results and is being expanded to other fields
- Continue to increase use of permanent magnetic motors (PMM) leading to electrical savings
- Well servicing team continued to improve job time efficiency

**Excluding CGP1 maintenance and asset divestitures, maintained production from 4Q21 to 1Q22**

## CGP1 UNDERWENT MAINTENANCE IN 1Q22

- CGP1 underwent a plant turnaround in 1Q22 to benefit from lower costs of materials and to optimize yields in the summer of 2022
- Performed a successful and safe maintenance turnaround in a quicker period than initially forecasted
- Estimating full return to pre-turnaround production levels of Natural Gas and NGLs in 2Q22
- 1Q22 production impact of ~5 MBOE/D (60% NGLs) | FY22E production impact of ~1.5 MBOE/D

(1) Average production for the three months ended December 31, 2021, less average production for the three months ended March 31, 2022. Includes Lost Hills and Ventura production. (2) Wells drilled includes steam injectors and drilled but uncompleted wells, which are not included in the SEC definition of wells drilled (3) Wells online reflects gross wells drilled, completed and producing, excluding outside operated wells. 1Q22 wells online excludes 2 wells that were funded in 2021 but were turned online in 1Q22. (4) Peak IP rate defined as highest production achieved during first 90 days of production. (5) IRRs were calculated using $98/BBL Brent and $5.30 NYMEX for 2022 and strip pricing as of 4/25/22 for 2023 onward.

# Expanding the Drilling Program

### EXPANDING OUR 2022 DRILLING PROGRAM:

- Increasing the rig count to 5 via an additional rig at the Wilmington Field in the Los Angeles Basin from July 2022
- Planning to drill 13 high confidence wells (10 producers and 3 injectors) in the Ranger, Terminal and Tar Formations
- Raising 2022 oil production guidance by 1 MBO/D to 61 to 57 MBO/D range from 60 to 56 MBO/D
  - Expected to increase the exit rate by 1.5 MBO/D[1] at current prices
- Expected to increase 2022 D&C Capital by $25 MM for Low Carbon Intensity Barrels, 100% crude production

Raising 2022 oil production guidance by

**~1 MBO/D**

#### 5th Rig Program (Wilmington) – Project Well Economics[2]

| Well Cost | TTM | BOE/D Max IP | BOE/D Peak | BO/D Oil Peak | EUR MBOE | IRR | PAYOUT |
|---|---|---|---|---|---|---|---|
| ~$1.6 MM | 15 Days | 82 | 730 | 730 | 1,660 | 168% | 1.2 yrs. |

### LOS ANGELES BASIN OPERATIONS AT GLANCE:

#### Scope/Scale/Characteristics

- Active extended reach, waterflood operations
- Depth: 2,000’ to 10,000’
- Porosity: 22% to 27%
- Permeability: 1 to 1,000 MD
- API: 13° to 22° (avg. 18°)

#### Production and Reserves[3]

- 2021 Gross production of ~28 MBOE/D
- 140 MMBOE Proved, 75 Unproved
- 99 MMBOE PDP, 11 MMBOE PDNP and 30 MMBOE PUD

#### Operations Excellence /Infrastructure

- Operated under a production sharing contract
- Low maintenance capital wells produced with electrical submersible pumps
- Consolidated footprint adjacent to multiple large industrial sources LA / Port


(1) Based on Brent pricing averaging $98/bbl for 2022 and includes PSC effects at that level. (2) Well economics reflect 10 producer wells and uses 2022 commodity prices of $98/bbl per barrel of oil , $5.30 per Mcf for natural gas and strip pricing as of 4/25/22 for the following years. (3) Represents FY2021 Reserves at SEC prices as of December 31, 2021, and after factoring in price realizations reflect average realized pricing of $68.73 per barrel for oil, $52.81 per barrel for NGLs and $3.99 per Mcf for natural gas.

# Diverse Assets With Flexible Development Opportunities

- **World-class resource base** with a diverse asset base and extensive high-quality inventory; wells have a short cycle time and are cost-effective to drill, providing an advantage in oil price cycles
- **Proven operator** at managing and growing a profitable business with **strong historical F&D and recycle profitability performance**[1]

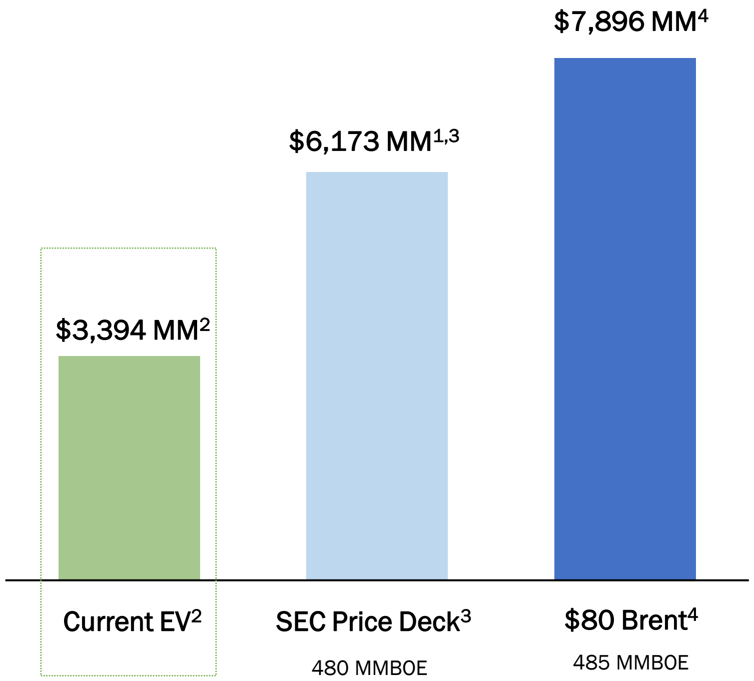
| Basin | Total Proved Reserves (MMBOE)[2] | Avg. Net Production (MBOE/D)[3] | % Oil / Liquids Production[3] | Net Mineral Acreage[4] (thousands) | Operations | Competitive Advantage |
|---|---|---|---|---|---|---|
| **Total** *(Net of Lost Hills)* | 471 | 95 | 59% / 73% | 1,762 | ● ● ● ● ● ● ● ● | **Portfolio Flexibility** |
| San Joaquin | 317 | 73 | 51% / 69% | 1,260 | ● ● ● ● ● ● ● ● | Big fields get bigger; substantial infrastructure in place; scale provides low-cost advantage |
| Los Angeles | 140 | 19 | 99% / 99% | 30 | ● ● ● ● | World-class waterfloods, cash flow positive |
| Sacramento | 14 | 3 | -- | 472 | ● ● | Large, scalable |

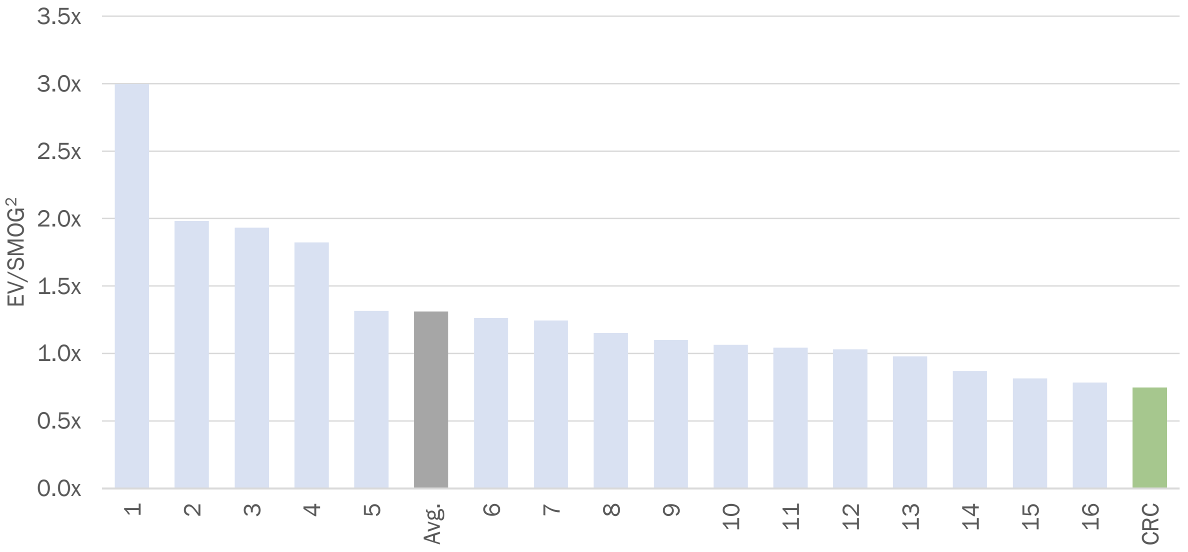
**Drive Mechanisms:** ● Conventional ● Unconventional ● Steamflood ● Waterflood ● Gas ● Tertiary Recovery ● CTV ● CCS+[5]

(1) 5-year trailing Organic Recycle Ratio average of 2.1x. (2) Represents FY2021 Reserves at SEC prices as of December 31, 2021, and after factoring in price realizations reflect average realized pricing of $68.73 per barrel for oil, $52.81 per barrel for NGLs and $3.99 per Mcf for natural gas. Excludes reserves tied to the Lost Hills and Ventura divestitures. Totals may not sum due to rounding. (3) Average net production and % Oil are from FY 2021 results less Lost Hills. (4) Net mineral acreage as per the 2021 10-K report. (5) Not included in CRC's reserves calculation.

# CRC's Reserves Value at Current Prices Demonstrates Equity Upside

## PV-10 OF PROVED RESERVES VALUE[1] AND METRICS AT SEC PRICE DECK AND $80 BRENT PRICES



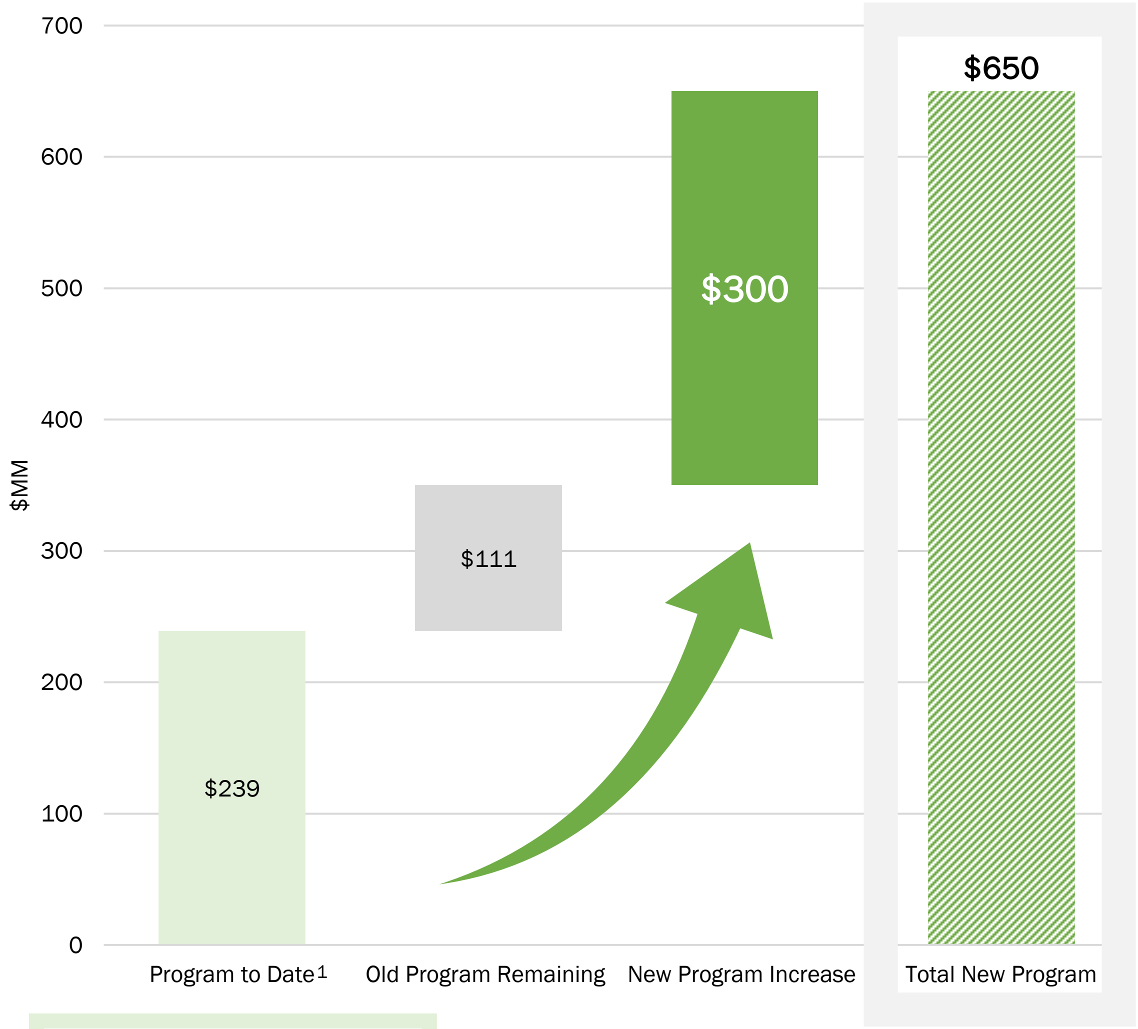




Source: FactSet and Company Documents. Peers include AR, BRY, CPE, CRGY, CRK, CTRA, KOS, MGY, MTDR, MUR, OAS, PDCE, RRC, SM, SWN and VET.

| | SEC Price Deck[3] | $80 Brent[4] |
|---|---|---|
| Total Proved Reserves / 2021 Exit Production[5] | 13.8 years | 14.0 years |
| PV-10[1] ($MM) | $6,173 | $7,896 |
| PV-10[1] / Net Debt[1] ($) | 22.7x | 29.0x |
| Net Debt[1] / Total Proved Reserves ($/BOE) | $0.57 | $0.56 |
| EV[2]/Total Proved Reserves ($/BOE) | $7.07 | $7.00 |
| PV-10[1] /Total Proved Reserves ($/BOE) | $12.86 | $16.28 |
| EV[2] / PV-10[1] ($) | 0.6x | 0.4x |

(1) PV-10 is as of December 31, 2021. Net Debt is as of March 31, 2022. PV-10 and Net Debt are non-GAAP measures. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. (2) CRC enterprise value calculated using Net Debt as of March 31, 2022, of $272 MM plus market capitalization as of April 29, 2022, using 77.631 MM shares outstanding. (3) Represents FY2021 Reserves at SEC prices as of December 31, 2021, and after factoring in price realizations reflect average realized pricing of $68.73 per barrel for oil, $52.81 per barrel for NGLs and $3.99 per Mcf for natural gas. (4) Average realized prices used to estimate our reserves were ~$80 per barrel for oil, ~$60.85 per barrel of NGLs and ~$4.40 per Mcf for natural gas. GAAP does not prescribe a standardized measure of reserves on a basis other than SEC pricing. As such, no standardized measure of proved reserves using ~$80 per barrel for oil, ~$60.85 per barrel of NGLs and ~$4.40 per Mcf for natural gas has been provided. (5) Calculated using annualized December 2021 production.

# Share Repurchases to Date




| | |
|---|---|
| Shares (MM) | 6.21 |
| $/share | $38.40 |

**Expanding the SRP by $300 MM**
and extending the program through 2Q23

**Share Repurchase Program**

- Repurchased ~$239 MM since the inception of the program[1]
- Repurchased ~$91 MM in 2022[1]
- $650 MM Share Repurchase Program in place through June 30, 2023

**Dividends**

- Paid ~$27 MM in dividends to date
- Announced a dividend of $0.17 per share for shareholders as of June 1, 2022, and payable on June 16, 2022
- Funded by Free Cash Flow

(1) As of April 29, 2022.

# Raising the 2022 Corporate Guidance

| REVISED CRC GUIDANCE[1] | Prior E&P, Corp. & Other | Revised E&P, Corp. and Other | Prior CMB | Revised CMB | Prior FY22E | Revised FY22E |
|---|---|---|---|---|---|---|
| Total Production[2] (MBOE/D) | 93 to 90 | 94 – 91 | — | — | 93 to 90 | **94 - 91** |
| Oil Production[2] (MBO/D) | 60 to 56 | 61 - 57 | — | — | 60 to 56 | 61 to 57 |
| Operating Costs ($MM) | $640 to $670 | $680 - $720 | — | — | $640 to $670 | $680-$720 |
| Carbon Management Expenses[3] ($MM) | — | — | $30 to $40 | $45 to $55 | $30 to $40 | $45 to $55 |
| Adj. G&A[4] ($MM) | $155 to $175 | $155 to $175 | $10 to $15 | $10 to $15 | $165 to $190 | Reaffirmed |
| Adj. EBITDAX[4] ($MM) | $800 to $940 | **$930 - $1,015** | ($40) to ($55) | ($55) to ($70) | $745 to $900 | **$860 to $960** |
| Capital ($MM) | $300 to $335 | $325 - $360 | $30 to $40 | $15 to $25 | $330 to $375 | $340 to $385 |
| Free Cash Flow[4] ($MM) | $350 to $450 | **$425 - $480** | ($70) to ($95) | ($70) to ($95) | $255 to $380 | **$330 to $410** |

## 2022 Guidance updated for:

**Drilling program expansion**
- Continued strong operational performance (drilling program, maintenance program and workover opportunities)
- Addition of a drilling rig in Los Angeles Basin in 2Q22 for a 13 high confidence wells program for ~$25 MM in capital

**Market Dynamics**
- Above expectations increase in Natural Gas pricing and subsequent increase in energy related operating costs, but CRC is net long in Natural Gas
- Higher Oil and NGL realized pricing

**CMB**
- Adjusting CMB capital lower as acquired leases and fee interests for carbon management activities will be reflected as expenses outside of the capital program

## Reaffirming 2022 Operational Goals

- **Continued strong E&P operational performance (horizontal drilling program and workover opportunities)**
- **Expecting to exit 2022[1,2] at or above 2021 exit oil production rate of ~58.5 MBO/D**

**~17% Increase in FCF Guidance & 1,000 BOE/D Raise in Production Guidance**

(1) Current guidance assumes a 2022 Brent price of $98 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $5.30 per mcf. CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. (2) 2022E production ranges subject to PSC effects and account for the Ventura and Lost Hills divestitures as well as CGP1 downtime. (3) CMB expenses include start-up expenditures. (4) Adj. EBITDAX, E&P, Corp. & Other Adj. EBITDAX, Adj. G&A. E&P, Corp. & Other Adj. G&A, Free Cash Flow and E&P, Corp. & Other Free Cash Flow are non-GAAP measures. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. Reconciliations of 2022E Adj. EBITDAX, Adj. G&A and Free Cash Flow to their nearest GAAP equivalent can be found on slides 25 to 27.

# Carbon Management Business

# Expanding Carbon Management Business to the Bay Area

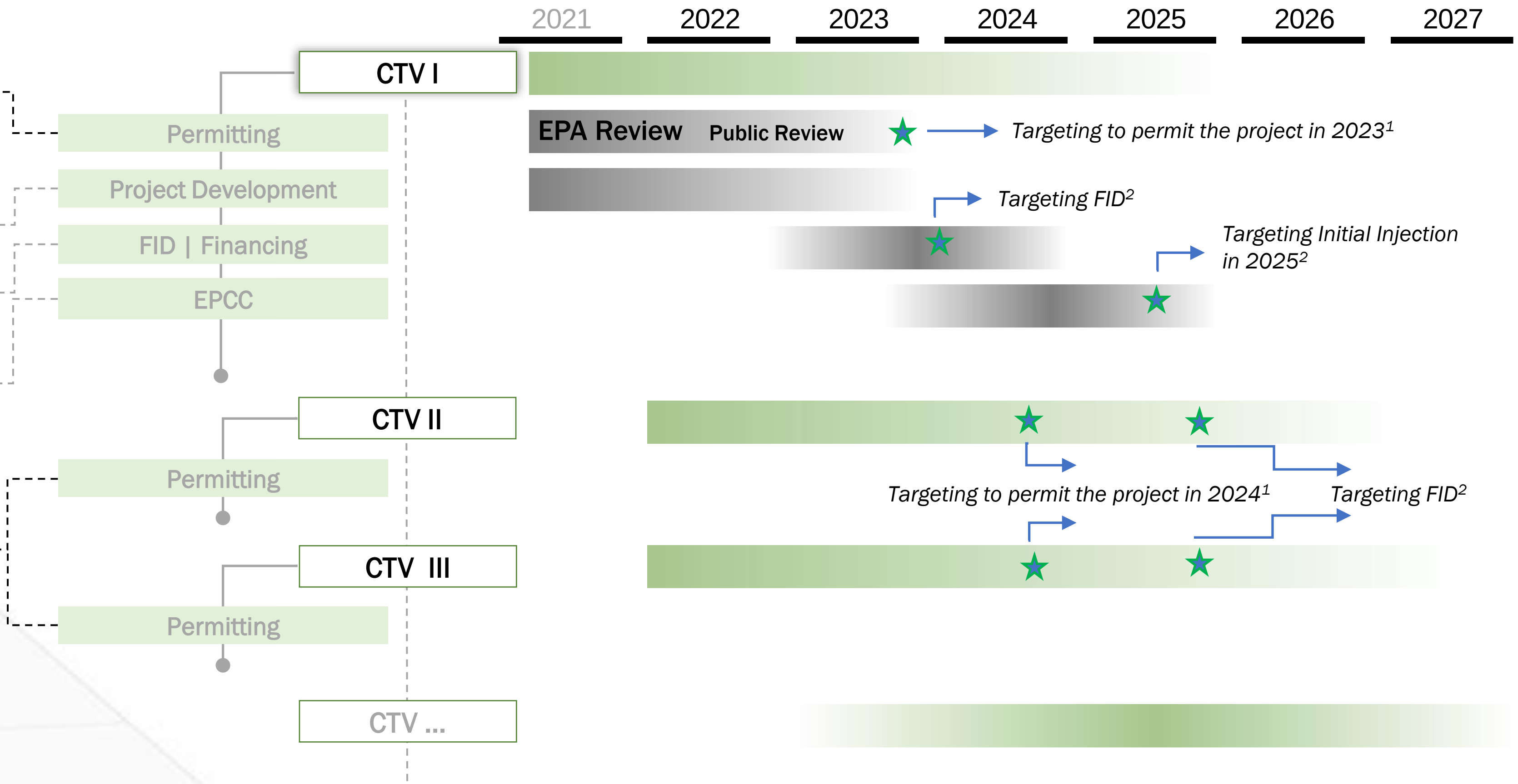
*Submitted 2 Class VI EPA Permits for a total of 40 MMT, Kern County CUP, EIR and Monitoring, Reporting and Verification Plan (MRV/45Q) | LCFS to be submitted in 3Q22 | Additional permitting in progress*

*In Concurrent Process*

*Concurrently Exploring Options*

*TBA*

***Submitted 2 New Class VI EPA Permits for a total of 80 MMT of $CO_2$ Sequestration in Sacramento basin in proximity to >10 MMTPA of emissions***




CARBON TERRAVAULT

**Scalable** business model that
**Lowers Carbon Emissions** & **Drives Value**

**Early-Stage Development Goals:**

- 1st Injection by YE2025 | 5 MMTPA injection by YE2027

**2022 Goals**

- Announce Carbon TerraVault Emissions Source(s)
- 200 MMT of $CO_2$ permits by YE2022

| 200 MMT | 120 MMT | 80 MMT |
|---|---|---|
| Goal | Permits Submitted | Not Permitted |

Source: Internal estimates. (1) EPA review estimated to take approximately 18 months followed by a public review estimated to take 3 to 6 months. (2) Source dependent for capture system. First injection date dependent on permitting, capture facility type and the structure, financing and ownership of the project which have not yet been negotiated.

# CalCapture CCS+

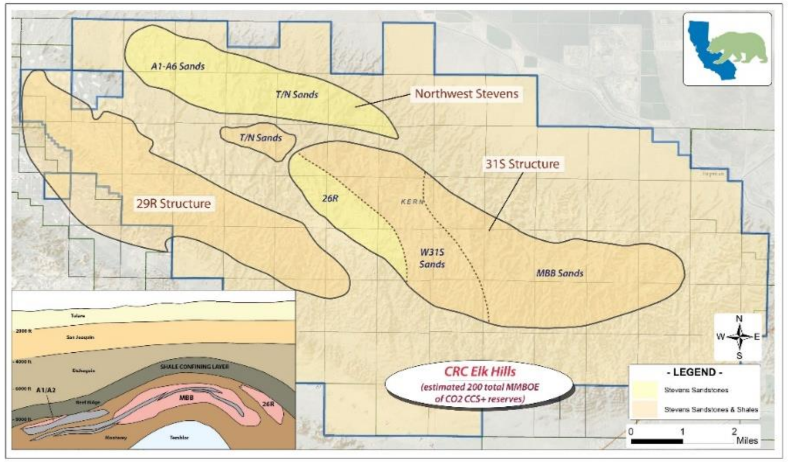
# Progressing CalCapture on the Path to 2045 Full Scope Net Zero

## PROJECT DETAILS

- Emissions Source: ~1.4 – 1.6 MMTPA of $CO_2$ emissions from a 550 MW Combined Cycle Elk Hills Power Plant & added carbon capture infrastructure
- $CO_2$ Sequestration/CCS+ Target: Elk Hills Stevens Sand Oil Reservoir with > 750 ft thick confirmed seal and above expectations pressure limits (Reservoir is expected to be LCFS compliant and qualify for 45Q)
- Incentives: 45Q eligible ($35/MT); ~1/3 of $CO_2$ captured eligible for LCFS; potential future cost avoidances under C&T[1]
- Operations team: Fully integrated with E&P operations

The Path to full SCOPE net ZERO

### Successful Waterflood History Primed for $CO_2$ Recovery

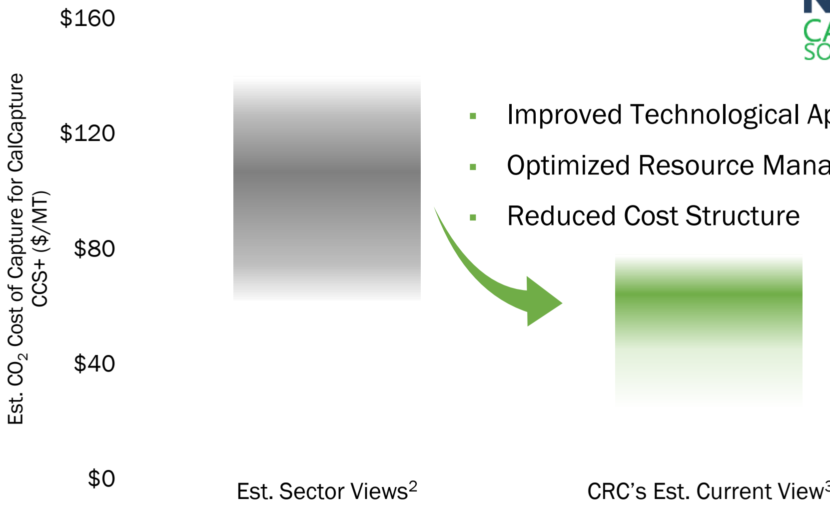



### DOE FEED Study

- Identified areas of further focus and improvement
- Pursued alternatives benchmarking & cost proposals
- Evaluated operational & technical optimization & new contracting strategy

### Improving Cost Outlook

NEXT CARBON SOLUTIONS




- Improved Technological Approach
- Optimized Resource Management
- Reduced Cost Structure

(1) Pending CARB development of rulemaking and standards. (2) Est. sector views includes the average range of $CO_2$ capture for NGCCs from: Energy Futures Initiative and Stanford University, "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions", October 2020 and National Petroleum Council, " Meeting the Dual Challenge – A Roadmap to at-scale deployment of Carbon Capture , Use, and Storage", March 2021. (3) CRC's est. current view includes the most recent economic evaluations from several viable technological partners working on the CalCapture CCS+ project.

# Providing the Potential for the First "Net Zero" Barrel of Oil to California

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

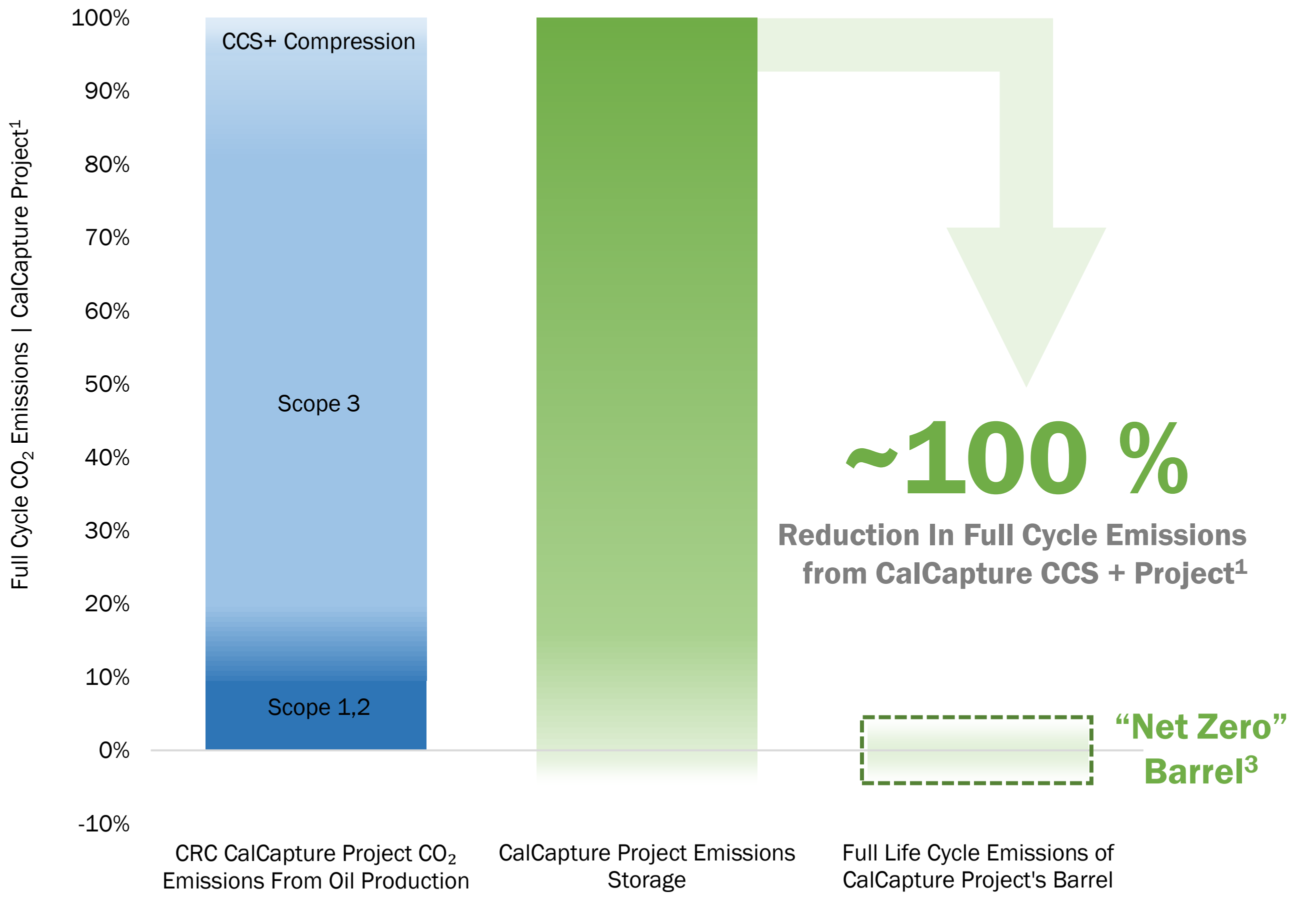
**28 MMT**

of $CO_2$ stored[1] over the life of the project

Stored annual $CO_2$ equivalent to

**300k**

emissions free passenger vehicles[2]




Source: Internal estimates. (1) Assumes 20 years project life, ~50 MMBO of reserves with an average ~7 MBO/D of crude production over project life, average injection of 1.4 MMTPA of $CO_2$. Depending on ultimate recovery factors, produced barrels could be carbon negative or may require additional offsets. (2) Source: EPA. Based on 1.4 MMT of $CO_2$ stored per year and average passenger vehicle emissions of 4.6 MT of $CO_2$ per year. (3) Assumes carbon intensity of 526 kg/bo for CalCapture CCS+ Project's barrel of crude oil.

# Supplemental Materials

# Positioning CRC to Lead The Energy Transition in California and Beyond

*"CRC's ESG goals demonstrate our commitment to the energy transition, and we are proud that CRC successfully continues on a path to provide safe and reliable low carbon intensity fuel and develop carbon capture and storage (CCS) and other emissions reducing projects"*

*- Mac McFarland, CRC President & CEO*


## 2045 Full-Scope Net Zero Goal

- Planning to permanently store captured or removed carbon emissions equal to CRC's Scope 1, 2 and 3 emissions by 2045
- Aligned with State of California's 2045 Net Zero ambitions
- Carbon management projects provide line-of-sight progress
- California incentives provide potential to achieve targets economically

## Ethnic and Gender Diversity Leadership Goal

- Maintain greater than 20% of ethnically diverse professionals in leadership positions
- Increase females in leadership positions to 30%
- Maintain current board composition with at least 30% ethnically and gender diverse board members

## Executive Pay Goal

- 30% of executive annual incentive pay related to company performance to ESG metrics

## Methane Emissions Reduction Goal

- Further reduce methane emissions by 30% from our 2020 baseline by 2030

## Freshwater Usage Reduction Goal

- Reduce freshwater usage in our low carbon intensity fuel production by 30% from our 2022 baseline by 2025 – exceeding California's voluntary 15% water use reduction target

## Community Giving Goal

- Continue targeted charitable giving to support local non-profits and community organizations across California

# Legacy RBL Oil Hedging Breakdown

**~ 90%** of 2022 and 2023 estimated remaining settlement payments are associated with hedges that were required by our RBL lenders in October 2020

**HEDGE CONTRACT SETTLEMENTS EXPECTED TO SIGNIFICANTLY DECREASE IN 2023[1]**

| Est. Contract Settlements | 2021A | 1Q22A | 2Q22E | 3Q22E | 4Q22E | 2022E | 1H23E | 2H23E | 2023E | 2024E |
|---|---|---|---|---|---|---|---|---|---|---|
| Required Initial RBL Hedges[2,3] ($MM) | | | ($172) | ($159) | ($112) | ($443) | ($161) | ($96) | ($257) | – |
| Required Subsequent RBL Hedges and Rollups[2,4] ($MM) | | | ($12) | ($5) | ($8) | ($25) | ($27) | ($51) | ($78) | ($11) |
| Strategic Hedges[2,5] ($MM) | | | ($19) | ($16) | ($33) | ($68) | ($23) | ($14) | ($37) | – |
| **Total Est. Settlement Impact ($MM)** | **($319)** | **($181)** | **($203)** | **($180)** | **($153)** | **($717)** | **($211)** | **($161)** | **($372)** | **($11)** |

Increased the Floor Price[6] from the original hedges put on by the RBL from ~$41/BBL at the time of bankruptcy to ~$65/BBL

Entered into limited strategic hedges since Fall of 2021, only RBL compliance hedging

(1) Assumes commodity prices settle at price levels similar to March 31, 2022. (2) Represents estimated net cash settlement payments for derivative contracts as of 3/31/2022, except 2021 which are actuals for the twelve months ended December 31, 2021 and 1Q22 which are actuals for the three months ended March 31, 2022. (3) Required Initial RBL Hedges are hedges that were entered coinciding with the bankruptcy to comply with the RBL requirements. (4) Required Subsequent RBL Hedges are hedges that were put on after the bankruptcy to comply with the RBL rolling hedge requirement. Includes rollups of initial hedge option premiums. (5) Strategic Hedges were hedges done by CRC as part of its ongoing hedging strategy. (6) Floor price is the weighted average floor price of all positions that were put on at the RBL and all the current positions, including legacy, subsequent and strategic as of 3/31/22.

# Hedging Program

## STRATEGY

CRC's commodity hedging approach is expected to look different going forward given the additional flexibility with the revised RBL document; This strategy will nonetheless support capital allocation including oil production maintenance, interest payments on debt, fixed shareholder returns, and continued development of our carbon management business

## OIL HEDGE PROTECTION[1]

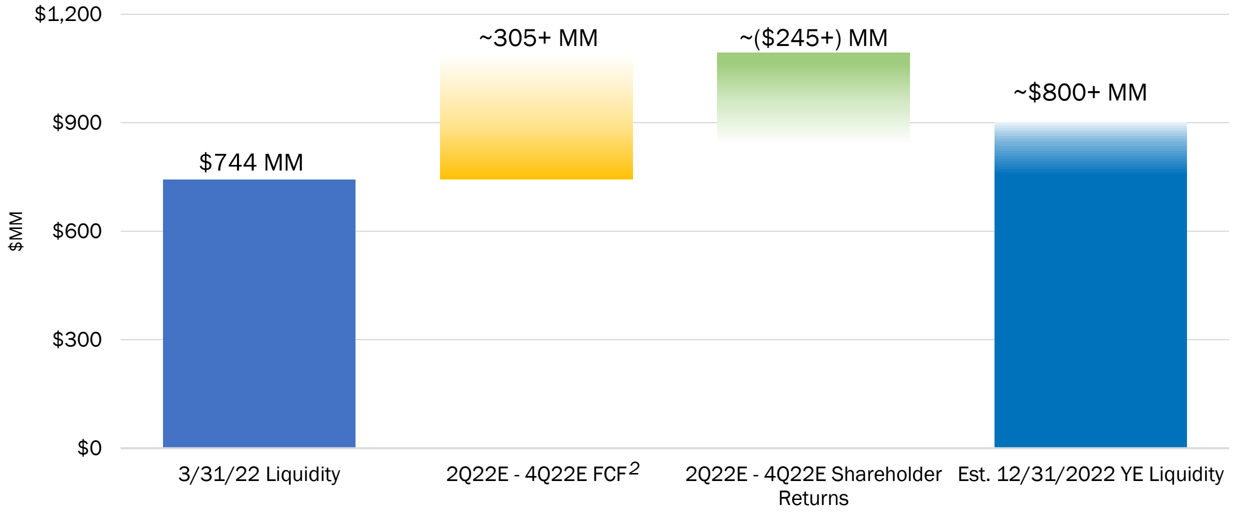
*Date as of March 31, 2022*

| | | 2Q22 | 3Q22 | 4Q22 | 1H23 | 2H23 | 2024 |
|---|---|---|---|---|---|---|---|
| SOLD CALLS | Barrels per Day | 35,343 | 34,380 | 25,167 | 18,078 | 11,555 | — |
| | Weighted-Average Price per Barrel | $60.63 | $60.76 | $57.82 | $58.63 | $57.06 | — |
| SWAPS | Barrels per Day | 10,669 | 10,476 | 17,263 | 11,806 | 16,552 | 1,492 |
| | Weighted-Average Price per Barrel | $54.12 | $53.97 | $58.79 | $58.04 | $62.95 | $79.06 |
| NET PURCHASED PUTS[2] | Barrels per Day | 35,343 | 34,380 | 25,167 | 18,078 | 11,555 | 1,724 |
| | Weighted-Average Price per Barrel | $65.42 | $65.02 | $64.47 | $76.25 | $76.25 | $75.00 |
| SOLD PUTS | Barrels per Day | — | 4,000 | 1,348 | — | — | — |
| | Weighted-Average Price per Barrel | — | $32.00 | $32.00 | — | — | — |

1) Hedges are based on weighted-average Brent prices per barrel. (2) Purchased and sold puts with the same strike price have been netted together.

# Maintaining Balance Sheet Strength, Liquidity, and Financial Flexibility

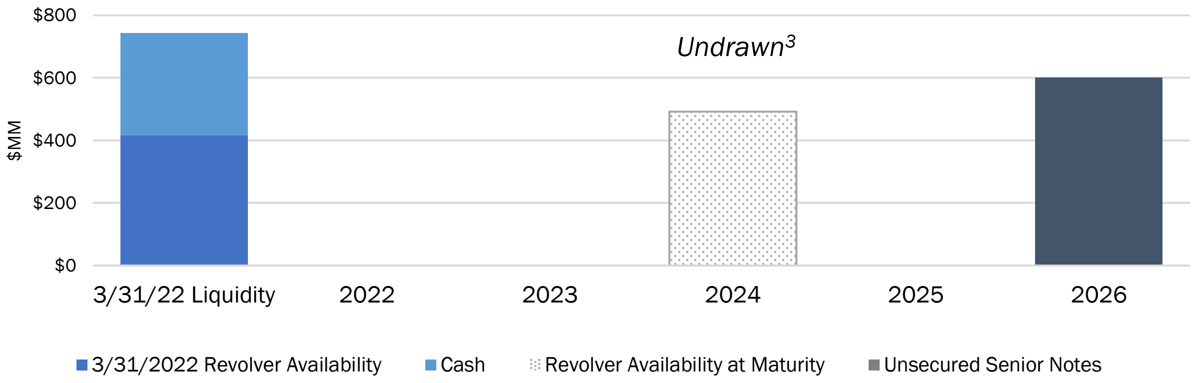
## ESTIMATED LIQUIDITY ROLL FORWARD[1]




## 3/31/22 DEBT SNAPSHOT

| ($MM) | | |
|---|---|---|
| Revolving Credit Facility (RCF) | $ | 0 |
| 7.125% Senior Notes | | 600 |
| **Face Value of Debt** | **$** | **600** |
| Less Available Cash | | (328) |
| **Net Debt** | **$** | **272** |

## NO SIGNIFICANT MATURITIES UNTIL 2026




## MULTIPLES DEMONSTRATE FLEXIBILITY

| ($MM) | |
|---|---|
| RCF Borrowing Base | $ 1,200 |
| 2022E Free Cash Flow[2] | $330 – $410 |
| YE 2022E Net Debt[1,2] / 2022E Adjusted EBITDAX[2] | 0.05x – 0.30x |
| 2022E Adjusted EBITDAX[2] / 2022E Interest & Debt Expense, net | 15.1x – 19.2x |

(1) Liquidity at 3/31/22 calculated as cash of $328 MM and $552 MM capacity on CRC's Revolving Credit Facility less $136 MM in outstanding letters of credit. Estimated YE 2022 liquidity assumes $552 MM capacity on CRC's Revolving Credit Facility less $136 MM in outstanding letters of credit. 2022 estimated FCF reflects the midpoint of 2022 Free Cash Flow guidance less $61 MM of FCF in 1Q22. 2022 estimated shareholder returns includes an annualized dividend payment of $0.17 over three quarters based on ~77 MM shares outstanding and a similar quarterly rate of repurchases as 1Q22, which are both subject to company discretion. (2) Adj. EBITDAX, Net Debt and Free Cash Flow are non-GAAP measures. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. Reconciliations of 2021E Adj. EBITDAX, Net Debt and Free Cash Flow to their nearest GAAP equivalent can be found in the Supplemental Materials on slides 25 to 27. (3) Undrawn revolver as of March 31, 2022.

# Adjusted EBITDAX Reconciliation

We define adjusted EBITDAX as earnings before interest expense; income taxes; depreciation, depletion and amortization; exploration expense; other unusual, infrequent and out-of-period items; and other non-cash items. We believe this measure provides useful information in assessing our financial condition, results of operations and cash flows and is widely used by the industry, the investment community and our lenders. Although this is a non-GAAP measure, the amounts included in the calculation were computed in accordance with GAAP. Certain items excluded from this non-GAAP measure are significant components in understanding and assessing our financial performance, such as our cost of capital and tax structure, as well as depreciation, depletion and amortization of our assets. This measure should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP. A version of Adjusted EBITDAX is a material component of certain of our financial covenants under our Revolving Credit Facility and is provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP. The following table represents a reconciliation of the GAAP financial measures of net income and net cash provided by operating activities to the non-GAAP financial measure of adjusted EBITDAX. CRC has supplemented its non-GAAP measures of consolidated adjusted EBITDAX with adjusted EBITDAX for its exploration and production and corporate items (Adjusted EBITDAX for E&P, Corporate & Other) which CRC believes is a useful measure for investors to understand the results of its core oil and gas business. CRC defines adjusted EBITDAX for E&P, Corporate & Other as consolidated adjusted EBITDAX less results attributable to its carbon management business (CMB).

| | FY 2022E | | CMB 2022E | | E&P, Corp. & Other 2022E | |
|---|---|---|---|---|---|---|
| *($MM)* | Low | High | Low | High | Low | High |
| Net income | $445 | $495 | ($70) | ($55) | $515 | $550 |
| Interest and debt expense, net | 50 | 57 | - | - | 50 | 57 |
| Depreciation, depletion and amortization | 200 | 220 | - | - | 200 | 220 |
| Exploration expense | 7 | 9 | - | - | 7 | 9 |
| Income Taxes | 211 | 256 | - | - | 211 | 256 |
| Unusual, infrequent and other items | | | | | | |
| Non-cash loss from commodity derivatives | (75) | (96) | - | - | (75) | (96) |
| Other | (35) | (47) | - | - | (35) | (47) |
| Other non-cash items | | | | | | |
| Accretion expense | 40 | 46 | - | - | 40 | 46 |
| Stock-based compensation | 15 | 18 | - | - | 15 | 18 |
| Post-retirement medical and pension | 2 | 2 | - | - | 2 | 2 |
| **Estimated Adjusted EBITDAX** | **$860** | **$960** | ($70) | ($55) | $930 | $1,015 |

| | FY 2022E | | CMB 2022E | | E&P, Corp. & Other 2022E | |
|---|---|---|---|---|---|---|
| *($MM)* | Low | High | Low | High | Low | High |
| Net cash provided by operating activities | $715 | $750 | ($70) | ($55) | $785 | $805 |
| Cash Interest | 44 | 54 | - | - | 44 | 54 |
| Cash Income Taxes | 30 | 40 | - | - | 30 | 40 |
| Exploration expenditures | 7 | 9 | - | - | 7 | 9 |
| Working capital changes | 64 | 107 | - | - | 64 | 107 |
| **Estimated Adjusted EBITDAX** | **$860** | **$960** | ($70) | ($55) | $930 | $1,015 |

# Leverage Ratio & Net Debt Reconciliations

## Leverage Ratio and Net Debt

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

| | FY 2022E | |
|---|---|---|
| *($MM)* | **Low** | **High** |
| Face value of debt | $600 | $600 |
| Estimated available cash[1] | (550) | (350) |
| **Estimated Net Debt** as of December 31, 2022 | **$50** | **$250** |
| 2022E Adjusted EBITDAX | $960 | $830 |
| **2022E Leverage Ratio** | **0.05x** | **0.30x** |

Note: Adj. EBITDAX and Net Debt are non-GAAP measures. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. (1) Inclusive of dividends and share repurchases. Please see slide 24 for a for a description of expected liquidity changes in 2022.

# Free Cash Flow & Adjusted General & Administrative Expenses Reconciliations

## Free Cash Flow

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

| | FY 2022E | | CMB 2022E | | E&P, Corp. & Other 2022E | |
|---|---|---|---|---|---|---|
| *($MM)* | **Low** | **High** | Low | High | Low | High |
| Net Cash Provided by Operating Activities | $715 | $750 | ($70) | ($55) | $785 | $805 |
| Capital Investment | (385) | (340) | (25) | (15) | (360) | (325) |
| **Estimated Free Cash Flow** | **$330** | **$410** | ($95) | ($70) | $425 | $480 |

## Adjusted General & Administrative Expenses

Management uses a measure called adjusted general and administrative (G&A) expense to provide useful information to investors interested in comparing our costs between periods and performance to our peers. The table below presents a reconciliation of G&A expense to adjusted G&A expense.

| | FY 2022E | | CMB 2022E | | E&P, Corp. & Other 2022E | |
|---|---|---|---|---|---|---|
| *($MM)* | **Low** | **High** | Low | High | Low | High |
| General & Administrative Expenses | $180 | $200 | $10 | $15 | $170 | $185 |
| Equity-settled Sock-based Compensation | (15) | (10) | - | - | (15) | (10) |
| **Adjusted General & Administrative Expenses** | **$165** | **$190** | $10 | $15 | $155 | $175 |

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