Forward Looking / Cautionary Statements

This presentation contains forward-looking statements that involve risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects. Such statements include those regarding our expectations as to our future:

- financial position, liquidity, cash flows and results of operations
- business prospects
- transactions and projects
- operating costs
- operations and operational results including production, hedging, capital investment and expected VCI
- budgets and maintenance capital requirements
- reserves
- type curves.

Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. While we believe assumptions or bases underlying our expectations are reasonable and make them in good faith, they almost always vary from actual results, sometimes materially. We also believe third-party statements we cite are accurate but have not independently verified them and do not warrant their accuracy or completeness. Factors (but not necessarily all the factors) that could cause results to differ include:

- commodity price changes
- debt limitations on our financial flexibility
- insufficient cash flow to fund planned investment
- inability to enter desirable transactions including asset sales and joint ventures
- legislative or regulatory changes, including those related to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products
- unexpected geologic conditions
- changes in business strategy
- inability to replace reserves
- insufficient capital, including as a result of lender restrictions, unavailability of capital markets or inability to attract potential investors
- inability to enter efficient hedges
- equipment, service or labor price inflation or unavailability
- availability or timing of, or conditions imposed on, permits and approvals
- lower-than-expected production, reserves or resources from development projects or acquisitions or higher-than-expected decline rates
- disruptions due to accidents, mechanical failures, transportation or storage constraints, natural disasters, labor difficulties, cyber attacks or other catastrophic events
- factors discussed in “Risk Factors” in our Annual Report on Form 10-K available on our website at crc.com.

Words such as "anticipate," "believe," "continue," "could," "estimate," "expect," "goal," "intend," "likely," "may," "might," "plan," "potential," "project," "seek," "should," "target," "will" or "would" and similar words that reflect the prospective nature of events or outcomes typically identify forward-looking statements. Any forward-looking statement speaks only as of the date on which such statement is made and we undertake no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

See www.crc.com Investor Relations for important information about 3P reserves and other hydrocarbon resource quantities, finding and development costs, recycle ratio calculations, and drilling locations.
Value Proposition – Multiple Ways to Increase Valuation

**Positioned to move from Defense to Offense**

- Increasing Investments and Deploying Rigs
- Joint Ventures
- Opportunistic Deleveraging
- Operating Leverage to Crude Oil

**Disciplined Portfolio Management**

- 135 Fields
- 4 Producing Basins
- 100+ Producing Horizons

**EBITDAX Growth**

*See Slide 25 for additional information regarding EBITDAX Growth planning scenarios*
CRC’s Large Resource Base with Advantaged Infrastructure

**World-Class Resource Base**
- Operate in 4 of 12 largest fields in the continental U.S.
- 568 MMBOE proved reserves
- 128 MBOE/d production, 77% liquids
- 2.3 million net mineral acres
- Low, flattening decline rate

**Positioned to Grow**
- Internally funded capital program designed to live within cash flow and drive growth
- Operating flexibility across basins and drive mechanisms to optimize growth through commodity price cycles
- Increasing crude oil mix improves margins
- Deep inventory of high-return projects

Reserves as of 12/31/16; Production figures reflect average 3Q 2017 rates.
Largest California Producer with Deep Regional Insight

Top California Producers in 2016*

<table>
<thead>
<tr>
<th>Company</th>
<th>Gross Operated MBoe/d</th>
</tr>
</thead>
<tbody>
<tr>
<td>CRC</td>
<td>177</td>
</tr>
<tr>
<td>Chevron USA</td>
<td>154</td>
</tr>
<tr>
<td>Aera Energy</td>
<td>129</td>
</tr>
<tr>
<td>Sentinel Peak</td>
<td>33</td>
</tr>
<tr>
<td>Berry</td>
<td>26</td>
</tr>
</tbody>
</table>

Majority of CA Production is Shallow*

- CRC: 16%
- Chevron USA: 23%
- Aera Energy: 22%
- Sentinel Peak: 29%
- Berry: 29%

OPEX $/Boe**

- CRC: $16
- Chevron USA: $23
- Aera Energy: $22
- Sentinel Peak: $29
- Berry: $29

Largest 3-D Seismic Position in California

- TULARE SANDS
- ETCHEGOIN SANDS
- MONTEREY SANDS AND SHALES
- TEMBLOR SANDS
- EOCENE SANDS AND SHALES
- UPPER CRETACEOUS SANDS AND SHALES

Production Mix

- Shallow
- Deeper (>5,000’)

*Source: DOGGR data (average production data for 2016), IHS, Wood Mackenzie, Company Estimates

*For non-CRC Companies, estimated 2016 OPEX $/Boe

* * * *
Post-Spin Transformation

**CRC Focus**
- **Culture**
  - Silo / Separate
  - One CRC
- **Regulatory Engagement**
  - Reactive
  - Proactive
- **Employee Engagement**
  - Low
  - High

**Financial Priorities**
- **Debt**
  - $7BN
  - $4BN
- **Capital Efficiency**
  - Low
  - High
- **Annual Production Costs**
  - $1.2BN
  - $750MM

**Portfolio Management**
- **Maintenance Capital**
  - High
  - Low
- **Product Focus**
  - Rate
  - Value
- **Actionable Inventory**
  - Low
  - High

**Strategic Flexibility**
- **Capital Flexibility**
  - Preservation
  - Acceleration
- **Production Growth Trajectory**
  - Decline
  - Growth
- **Price Outlook**
  - Trough
  - Peak

**Notes:**
- Financial Priorities
  - Debt: $7BN to $4BN
  - Capital Efficiency: Low to High
  - Annual Production Costs: $1.2BN to $750MM

**Other Highlights:**
- Culture: Silo / Separate to One CRC
- Regulatory Engagement: Reactive to Proactive
- Employee Engagement: Low to High
- Portfolio Management: High to Low
- Maintenance Capital and Product Focus: High to Low
- Actionable Inventory: Low to High
- Capital Flexibility: Preservation to Acceleration
- Production Growth Trajectory: Decline to Growth
- Price Outlook: Trough to Peak

**Key Financial Figures:**
- Debt: $7BN to $4BN
- Annual Production Costs: $1.2BN to $750MM
Life of Field Plans – Growing Inventory

- Comprehensive technical review of 40% of CRC’s fields
- Updated Geologic models, OOIP
- Teams shared analog experience across CRC
- Cataloged opportunities consistent with our proven reserves methodology
- Rolled into our portfolio ranking process

3P Resource Growth

<table>
<thead>
<tr>
<th>MMBoe</th>
<th>2016</th>
<th>Spin-off</th>
</tr>
</thead>
<tbody>
<tr>
<td>Produced</td>
<td>768</td>
<td>321</td>
</tr>
<tr>
<td>Proven</td>
<td>568</td>
<td>251</td>
</tr>
<tr>
<td>Price Affected Reserves</td>
<td>110</td>
<td>110</td>
</tr>
<tr>
<td>Unproven</td>
<td>826</td>
<td>826</td>
</tr>
</tbody>
</table>

>250% Growth
Deep Inventory of Actionable Projects at $55 Brent

**Portfolio Spectrum**

- Growth portfolio focus, **fully burdened**
- All projects meet VCI 1.3 threshold at $55 Brent and $3.50 NYMEX, and deliver robust cash flow
- Portfolio has large contributions from all recovery mechanisms and reserves types
- Many projects take advantage of existing infrastructure, while other new projects may require infrastructure investment in facilities and sales points

Full cycle costs = operating costs + development costs + facility costs + field-level G&A + taxes other than on income
* See www.crc.com, Investor Relations for details regarding net resources.
Resilient Resource Base

Note: Due to consolidated financials, capital and production for 2017 includes BSP’s investment.
Moving from Defense to Offense

- CRC 2017 capital plan will be directed to oil-weighted projects in our core fields: Elk Hills, Wilmington, Kern Front, Buena Vista, Mt. Poso, Pleito Ranch, Wheeler Ridge and the delineation of Kettleman North Dome
- JV capital is mainly focused in the San Joaquin Basin
- We have a dynamic plan which can be scaled up or down depending on the price environment to live within Cash Flow

2017E Total Capital Plan

Total: ~$400 million

Drilling $105 (26%)
Development Facilities $45 (11%)
Workover $60 (15%)
JV - Capital $160 (40%)
Other $20 (5%)
Exploration $10 (3%)

2017E Drilling Capital – By Drive

Total: Up to $265 million

Conventional: 42%
Waterfloods: 29%
Steamfloods: 17%
Unconventional: 7%
Exploration: 5%

2017E Drilling Capital – By Basin

Total: Up to $265 million

San Joaquin: 80%
Los Angeles: 9%
Ventura: 11%
Joint Ventures: A Force Multiplier

**$550 Million**
Total Potential JV Capital

**Portfolio Flexibility and Optionality**

**$120 Million**
$260 MM Committed

**Enables High Margin Production Growth**

**~3.5-4.0 MBoe/d**
Gross Peak Production per $100 MM of development capital

**Accelerate Value**

**>12 MMBoe**
Potential Targeted Reserves per $100 MM of development capital

**Derisk Inventory**

JVs are currently focused in the San Joaquin Basin

JVs add production, cashflow, and help de-risk inventory to increase CRC’s reserve base
San Joaquin Basin – An American Super Basin

Overview

- Oil and gas discovered in the late 1800s
- 70% of CRC production is from San Joaquin Basin
- Cretaceous to Pleistocene sedimentary section (>25,000 feet)
- Source rocks are organic rich shales from Moreno, Kreyenhagen, Tumey and Monterey Formations
- Thermal recovery applied since 1960s
- Currently running 7 drilling rigs

Key Assets

- 3Q 2017 average net production of 89 MBOE/d (74% liquids)
- Elk Hills is the flagship asset (~58% of 3Q 2017 CRC San Joaquin production)
- Two core steamfloods - Kern Front and Lost Hills
- Early stage waterfloods at Buena Vista and Mount Poso

25 billion OOIP (BOE) in CRC fields
Elk Hills Area – CRC’s Flagship Asset

Overview

- CRC’s flagship, a 100 year-old field with exploration opportunities
- Light oil from conventional and unconventional production
- Largest gas and NGL producing field in California, one of the largest fields in the continental U.S.\(^1\), >3,000 producing wells
- 11 billion OOIP (BOE) and cumulative production of over 2.7 billion BOE
- 3Q 2017 average net production of 52 MBOE/d (~40% of total CRC production)

Integrated Infrastructure

- 590 MMcf/d processing capacity through 4 gas plants
  - Including California’s largest
- 3 CO\(_2\) removal plants
- Over 4,500 miles of gathering lines
- 45 MW cogeneration plant
- 550 MW power plant

\(^1\) DOGGR data and U.S. Energy Information Administration.

Large fee property position with integrated infrastructure

Field Map

Production History

- Net MBOEPD
- Rig Count


Net MBOE/d

Rig Count

0 20 40 60 80 100 120
Buena Vista Nose – Conventional: Development of Exploration Success

Overview

• Discovery Date: 2012
• Formation: Stevens Sandstone, Turbidities/Deep Marine
• 10,000’ average True Vertical Depth
• 32 API, 600 GOR. Initial pressure 4,760 psi
• 2016 Gross Rates: 1 MBOE/d gross (92% Oil)
• 5 active producers
• Reduced capital costs with a new well design (two strings)
• Anticipate waterflood pilot early 2018 (15 MMBbl upside)
• Exploration prospects surround the field

Type Curve

GROSS BOE/d

<table>
<thead>
<tr>
<th>YEAR</th>
<th>0</th>
<th>150</th>
<th>300</th>
<th>450</th>
<th>600</th>
<th>750</th>
<th>900</th>
</tr>
</thead>
</table>

See endnotes for important information about our type curves.

BV Nose Primary Potential Development

Growth potential near existing infrastructure

<table>
<thead>
<tr>
<th>OOIP (MMBO)</th>
<th>CUM PROD (MMBO)</th>
<th>RF</th>
</tr>
</thead>
<tbody>
<tr>
<td>95</td>
<td>1.9</td>
<td>2%</td>
</tr>
</tbody>
</table>
Overview

- World-class hydrocarbon-rich sedimentary basin with large quantities of stacked pay
- ~10 billion barrels OOIP in CRC fields
- Kitchen is the entire basin, hydrocarbons did not migrate laterally; basin depth (>30,000 ft)
- Very few penetrations >10,000 ft, leaving deep horizons underexplored
- Focus on mature waterfloods with generally low technical risk and proven repeatable technology across huge OOIP fields
- 3Q 2017 average net production of 27 MBOE/d (99% liquids)
- Over 20,000 net mineral acres
- Major properties are premier coastal development assets of Wilmington and Huntington Beach

33% of 3Q 2017 CRC oil production is from the Los Angeles Basin
Ventura Basin – Birthplace of the California Oil Industry

Overview

- Prolific basin with a long history, including the first commercial oil well in California
- ~8 billion barrels OOIP in CRC fields
- Operate 26 fields (over half the fields in the basin)
- ~250,000 net mineral acres (75% undeveloped)
- 3Q 2017 average net production of 6 MBOE/d (83% liquids)
- Portfolio of drive mechanisms: Primary, New & Redevelopment Waterfloods and Steamfloods
- Building off exploration success: Targeting potential 1,000 BOE/d IP wells along Oak Ridge Fault
- Incorporating 10 square miles of 3D seismic into drillable locations
- Significant upside: movable oil, low recovery factor, controlling acreage position and existing infrastructure

<table>
<thead>
<tr>
<th>OOIP (MMBO)</th>
<th>CUM PROD (MMBO)</th>
<th>RF</th>
</tr>
</thead>
<tbody>
<tr>
<td>7,843</td>
<td>813</td>
<td>10%</td>
</tr>
</tbody>
</table>

High Growth Area: large OOIP, low recovery factor & potential for high-IP wells
Sacramento Basin – Significant Gas Optionality

Overview

- Exploration started in 1918 and focused on seeps and topographic highs. In the 1970s the use of multifold 2D seismic led to largest discoveries
- Cretaceous Starkey, Winters, Forbes, Kione, and the Eocene Domengine sands
- Most current production under 6,000 feet, deeper targets remain at less than 10,000 feet
- 3D seismic surveys in mid-1990s helped define trapping mechanisms and reservoir geometries
- 3Q 2017 average net production of 33 MMcf/d (100% dry gas)
- CRC produces 85% of basin gas with synergies from scale

California imports >90% of its natural gas requirements
Significant Debt Reduction from Post-Spin Peak

Chose options to maximize deleveraging and minimize recurring cost to the income statement on a per share basis. Continue to seek opportunistic transactions that reduce overall debt.

<table>
<thead>
<tr>
<th>2Q15</th>
<th>Debt Exchange for 2L</th>
<th>Open Market Repurchases</th>
<th>Equity for Debt Exchange</th>
<th>Cash Tender for Unsecureds</th>
<th>Cash Flow</th>
<th>3Q17</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7,000</td>
<td>6,765^1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>5,139</td>
</tr>
</tbody>
</table>

**Cumulative Debt Reduction**

<table>
<thead>
<tr>
<th>Total Net Principal Reduction</th>
<th>$535 million</th>
<th>$144 million</th>
<th>$102 million</th>
<th>$625 million</th>
<th>$220 Million</th>
<th>$1,626 million</th>
</tr>
</thead>
</table>

**Annual Income Statement Effect (Annualized Interest)**

<table>
<thead>
<tr>
<th></th>
<th>+$22 million</th>
<th>-$7 million</th>
<th>-$6 million</th>
<th>+$27 million</th>
<th>-$6 Million</th>
<th>$30 million</th>
</tr>
</thead>
</table>

1 Represents mid-second quarter 2015 peak debt.

2 Includes operating cash flow, as well as positive working capital and proceeds from asset sales in the first half of 2017.
### Pro Forma - Capitalization as of 9/30/17 ($MM)

<table>
<thead>
<tr>
<th>Category</th>
<th>Amount ($MM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1st Lien 2014 RCF</td>
<td>160</td>
</tr>
<tr>
<td>1st Lien 2017 Term Loan</td>
<td>1,300</td>
</tr>
<tr>
<td>1st Lien 2016 Term Loan</td>
<td>1,000</td>
</tr>
<tr>
<td>2nd Lien Notes</td>
<td>2,250</td>
</tr>
<tr>
<td>Senior Unsecured Notes</td>
<td>493</td>
</tr>
<tr>
<td><strong>Total Debt</strong></td>
<td>5,203</td>
</tr>
<tr>
<td>Less cash</td>
<td>(11)</td>
</tr>
<tr>
<td><strong>Total Net Debt</strong></td>
<td>5,192</td>
</tr>
<tr>
<td>Equity</td>
<td>(574)</td>
</tr>
<tr>
<td><strong>Total Net Capitalization</strong></td>
<td>4,618</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Ratio</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Net Debt / Total Capitalization</td>
<td>112%</td>
</tr>
<tr>
<td>Total Net Debt / LTM Adjusted EBITDAX</td>
<td>7.3x</td>
</tr>
<tr>
<td>LTM Adjusted EBITDAX / LTM Interest Expense</td>
<td>2.1x</td>
</tr>
<tr>
<td>PV-10 / Total Net Debt</td>
<td>1.0x</td>
</tr>
<tr>
<td>Total Net Debt / October 31, 2017 Proved Reserves ($/Boe)</td>
<td>$7.66</td>
</tr>
<tr>
<td>Total Net Debt / October 31, 2017 PD Reserves ($/Boe)</td>
<td>$11.46</td>
</tr>
<tr>
<td>Total Net Debt / Q3 2017 Production ($/Boepd)</td>
<td>$40,563</td>
</tr>
</tbody>
</table>

---

1. Pro forma capitalization table and debt maturities reflect completion of the amendment to the 2014 Credit Facilities and recent completion of the new 2017 Term Loan
2. Since 9/30/17 and subsequent to the amendment, the Company repurchased enough 2020 notes to eliminate the potential springing maturity trigger related to such notes
3. Excludes $17 million of restricted cash
4. See www.crc.com, Investor Relations for a reconciliation to the closest GAAP measure and other important information
5. PV-10 as of 10/31/17, see Attachment 2 of CRC’s Third Quarter Earnings Release from November 6, 2017 for details on this calculation

---

Pro Forma for the amendment to the 2014 Credit Facility and 2017 Term Loan which closed on November 17, 2017.

- The amendment extends the 2014 Revolver to June 2021 and relaxes financial covenants.
- On a pro forma basis, the Company has approximately $703 million of available borrowing capacity and $714 million of liquidity, not including $150 million minimum liquidity.
- Deleveraging remains a priority; ~$1.6 billion decrease to date from post-spin peak.
- ATM shelf facility provides CRC with additional flexibility, effectively another tool in our toolbox to enhance value and will be used judiciously.

---

**Pro-Forma Debt Maturities ($MM)**

<table>
<thead>
<tr>
<th>Debt Maturity</th>
<th>Amount ($MM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014 RCF</td>
<td>$1,300</td>
</tr>
<tr>
<td>2017 Term Loan</td>
<td>$2,250</td>
</tr>
<tr>
<td>2016 Term Loan</td>
<td>$1,000</td>
</tr>
<tr>
<td>2nd Lien Notes</td>
<td>$160</td>
</tr>
<tr>
<td>Senior Unsecured Notes</td>
<td>$165</td>
</tr>
</tbody>
</table>

*The 2014 Credit Facility, the 2017 Term Loan and the 2016 Term Loan have springing maturities related to the 2021 notes. The springing maturity trigger related to the 2020 notes has been eliminated through recent repurchases. The 2017 Term Loan also has a springing maturity related to the 2016 Term Loan.*
Updated Capital Structure – Improved Liquidity

**Debt Hierarchy**

- **2014 Revolving Credit Facility Capacity** - $1 billion
- **New**
  - 2017 Term Loan - $1.3 billion
  - 2016 Term Loan - $1 billion
  - 2015 Second Lien - $2.25 billion
  - Unsecured Notes - $0.493 billion

---

**Reduced Revolver Utilization**

- Drawn Revolver $837
- Drawn Revolver $160

**Increased Liquidity**

- Liquidity $442
- Liquidity $714

---

*Subject to minimum liquidity requirement under 2014 Revolving Credit Facility*
History of Proactive Strategic Decisions

Swift, decisive actions through the commodity downturn have positioned CRC for growth. Proactive discussions with lenders and solid asset base provide a path to recovery and an actionable inventory.

1. Cut rig count/began hedging
2. Cut 2015 Capital Budget
3. Bank Amendments
4. Deleveraging and/or Capital Market Transactions
5. Increasing activity, invest within Cash Flow
6. JV Transactions
Reserves Value in Excess of EV

- Proved Value
- PDP Value
- Unproved
- Surface & Minerals
- Infrastructure

($Billion)

- $0
- $4
- $8
- $12
- $16
- $20

- $50 Brent
- $55 Brent
- $60 Brent

Current EV of $5.6 Bn

See endnotes in the Appendix.
CRC – Price Realizations

**Oil Price Realization (with Hedges)**

- **WTI**
  - 2015: $49.80
  - 2016: $48.80
  - 1Q 2017: $51.91
  - 2Q 2017: $50.92
  - 3Q 2017: $52.18

- **Realizations**
  - 2015: $42.01
  - 2016: $45.04
  - 1Q 2017: $47.98
  - 2Q 2017: $48.29
  - 3Q 2017: $50.02

- **Brent**
  - 2015: $53.64
  - 2016: $54.66
  - 1Q 2017: $50.24
  - 2Q 2017: $50.92
  - 3Q 2017: $52.18

**Realization % of WTI**
- 2015: 101%
- 2016: 99%
- 1Q 2017: 97%
- 2Q 2017: 99%
- 3Q 2017: 104%

**Gas Price Realization**

- **NYMEX**
  - 2015: $2.75
  - 2016: $2.66
  - 1Q 2017: $2.42
  - 2Q 2017: $2.28
  - 3Q 2017: $2.28

- **Realizations**
  - 2015: $3.26
  - 2016: $3.14
  - 1Q 2017: $3.06
  - 2Q 2017: $2.56
  - 3Q 2017: $2.56

**Realization % of NYMEX**
- 2015: 97%
- 2016: 94%
- 1Q 2017: 89%
- 2Q 2017: 79%
- 3Q 2017: 87%

**NGL Price Realization - % of WTI**

- 2015: 40%
- 2016: 52%
- 1Q 2017: 66%
- 2Q 2017: 62%
- 3Q 2017: 72%

- California refinery demand for native crude continues to be strong and reduction in heavy waterborne crude has positively influenced differentials.
- NGL prices have been supported by lower inventories and export markets.

CRC believes near-term differentials will remain strong.
Opportunistically Built Oil Hedge Portfolio

**Strategy**
Protect cash flow for capital investments and covenant compliance

<table>
<thead>
<tr>
<th></th>
<th>4Q 2017</th>
<th>1Q 2018</th>
<th>2Q 2018</th>
<th>3Q 2018</th>
<th>4Q 2018</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Sold Calls</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Barrels per Day</td>
<td>6,300</td>
<td>10,400</td>
<td>10,400</td>
<td>16,100</td>
<td>16,100</td>
</tr>
<tr>
<td>Weighted Average Ceiling Price per Barrel</td>
<td>$57.80</td>
<td>$59.38</td>
<td>$59.37</td>
<td>$58.91</td>
<td>$58.91</td>
</tr>
<tr>
<td><strong>Purchased Puts</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Barrels per Day</td>
<td>11,300</td>
<td>1,200</td>
<td>1,200</td>
<td>1,100</td>
<td>1,100</td>
</tr>
<tr>
<td>Weighted Average Floor Price per Barrel</td>
<td>$47.75</td>
<td>$45.82</td>
<td>$45.83</td>
<td>$45.83</td>
<td>$45.85</td>
</tr>
<tr>
<td><strong>Sold Puts</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Barrels per Day</td>
<td>-</td>
<td>29,000</td>
<td>29,000</td>
<td>19,000</td>
<td>19,000</td>
</tr>
<tr>
<td>Weighted Average Floor Price per Barrel</td>
<td>$-</td>
<td>$45.00</td>
<td>$45.00</td>
<td>$45.00</td>
<td>$45.00</td>
</tr>
<tr>
<td><strong>Swaps</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Barrels per Day</td>
<td>30,000*</td>
<td>29,000*</td>
<td>29,000*</td>
<td>19,000*</td>
<td>19,000*</td>
</tr>
<tr>
<td>Weighted Average Price per Barrel</td>
<td>$55.00</td>
<td>$60.00</td>
<td>$60.00</td>
<td>$60.13</td>
<td>$60.13</td>
</tr>
<tr>
<td><strong>Percentage of 3Q 2017 Oil Production Hedged</strong></td>
<td>50%</td>
<td>37%</td>
<td>37%</td>
<td>24%</td>
<td>24%</td>
</tr>
</tbody>
</table>

*For details and potential volume changes please see Attachment 8 of our 3Q 2017 Earnings Release and in our 3Q 2017 10-Q.
Portfolio Flexibility Provides Range of Crude Oil Scenarios

Combined with improving and stabilizing commodity prices, we are positioned for growth in:

- Cash flow
- Production
- Reserves

on a debt-adjusted per share basis

Capital focused on oil projects that provide

Increasing Margins + Low Decline Rates = Compounding Cash Flow

Estimated Crude Oil Production Outcomes

- 5% Production CAGR

Estimated Range of EBITDAX Outcomes

- 10% EBITDAX CAGR

Estimated Capital Invested

Note: Scenario 1 assumes $55 Brent for remainder of 2017 and $60 Brent and $3.50 NYMEX gas price thereafter. Scenario 2 assumes $55 Brent and $3.50 NYMEX gas price for the remainder of 2017 and thereafter. Assumes lease operating costs are equal to 2016 levels for the mid-point of the range of planning scenario outcomes. Ranges of portfolio planning scenario outcomes assume development of a variety of combinations of steamflood, waterflood, conventional and unconventional projects in our inventory and reflect estimates of geologic, development and permitting risk. All discretionary cash flow reinvested in business for each scenario.
The Case for CRC: Investment Thesis Overview

Investment Case for CRC

World-class assets with significant inventory
Resilient model that preserves optionality and protects downside
Focused on value and poised for growth

Competitive Advantages

Operational flexibility
Grow within cash flow
Industry leading decline rate
Integrated and complementary infrastructure

Why Own CRC Now

Positioned to go from defense to offense

Maintain Production
Production and Cash Flow Growth
Production
Innovation
Deep Inventory

Disciplined portfolio management

Potential for EBITDAX growth

Higher Oil to Gas Price Ratio
Lower Oil to Gas Price Ratio

Gas
Unconventional
Primary
Waterflood
Shallowfield
Shale

$MM


10% EBITDAX CAGR
Appendix
### Summary of Amendment to the 2014 Credit Facility

<table>
<thead>
<tr>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Revolver Commitment</strong></td>
</tr>
<tr>
<td>• 2014 Credit Facility consisting of $1.0 billion 2014 Revolver</td>
</tr>
<tr>
<td><strong>2017 Term Loan Indebtedness</strong></td>
</tr>
<tr>
<td>• Permit a $1.3 billion first lien term loan (the “2017 Term Loan”)</td>
</tr>
<tr>
<td>• Proceeds from 2017 Term Loan, net of 2% original issue discount, fees and expenses, used to completely repay the 2014 Term Loan and pay down the 2014 Revolver</td>
</tr>
<tr>
<td><strong>Maturity Extension</strong></td>
</tr>
<tr>
<td>• June 30, 2021, subject to the following springing maturity</td>
</tr>
<tr>
<td>‒ 273 days prior to the 2020 notes if outstanding 2020 notes ≥ $100 million</td>
</tr>
<tr>
<td>‒ 273 days prior to the 2021 notes if outstanding 2021 notes ≥ $100 million</td>
</tr>
<tr>
<td><strong>Non-Borrowing Base Asset Sale Proceeds</strong></td>
</tr>
<tr>
<td>• Net Cash Proceeds may be used to prepay junior indebtedness so long as Liquidity &gt; $250 million, such prepayment occurs at least at a 20% discount to par and subject to the following:</td>
</tr>
<tr>
<td>‒ 25% of the proceeds up to $500 million (excluding the Elk Hills Power Plant) shall be applied to repay drawings under the 2014 Revolver</td>
</tr>
<tr>
<td>‒ 50% of the proceeds in excess of $500 million and less than $1 billion (excluding the Elk Hills Power Plant) shall be applied to repay drawings under the 2014 Revolver</td>
</tr>
<tr>
<td>‒ 75% of the proceeds in excess of $1 billion (excluding the Elk Hills Power Plant) shall be applied to repay the 2014 Revolver and reduce commitments by a corresponding amount</td>
</tr>
<tr>
<td>‒ 50% of the proceeds of the Elk Hills Power Plant shall be applied to repay drawings under the 2014 Revolver</td>
</tr>
<tr>
<td><strong>Financial Covenants</strong></td>
</tr>
<tr>
<td>• 2014 Credit Facility Leverage Ratio:</td>
</tr>
<tr>
<td>‒ 2017-2019: ≤ 1.90x</td>
</tr>
<tr>
<td>‒ 2020-2021: ≤ 1.50x</td>
</tr>
<tr>
<td>• Minimum Interest Coverage Ratio: ≥ 1.20x</td>
</tr>
<tr>
<td>• First Lien Asset Coverage Ratio: ≥ 1.20x</td>
</tr>
<tr>
<td>• Minimum Liquidity: $150 million, tested monthly</td>
</tr>
<tr>
<td><strong>Other Terms</strong></td>
</tr>
<tr>
<td>• Incremental commitment capacity limited to $50 million</td>
</tr>
</tbody>
</table>

1 Defined as indebtedness outstanding under 2014 Credit Facility to LTM Consolidated EBITDAX.

Note: The full amendment was filed with 8K on November 13, 2017.
Accelerating Production Decline in U.S. Onshore Lower 48 Development Wells

Recent wells in the onshore Lower 48 are showing steeper declines

Source: Data from Wood Mackenzie, CRC analysis
Peers included: CLR, COG, CPE, CXO, DNR, EGN, EOG, EPE, FANG, HK, LPI, MRO, MTDR, MUR, NFX, OAS, PDCE, PE, PXD, QEP, RRC, RSPP, SM, SN, WLL, WPX, and XEC.

Source: Wood Mackenzie - Operated Production Data through 2016, CRC analysis
Proven Capital Efficiency Improvements

**Long Term Learning**
- Casing String Eliminated, Wellbore Strengthening, Rig Scheduling Efficiency

**29% Cost/ft Reduction**
- 12% Deeper
- 20% Total Reduction in Well Costs

**29R Unconventional - Drilling Cost Trend**

**BV Hills Drilling Efficiencies**

Since the last drilling campaign:
- 31% Reduction in Drilling Time
- 54% Reduction in Cost
Core Principle of Living within Cash Flow

2016 Unlevered Free Cash Flow

Unlevered Free Cash Flow ($MM)

Average: $(293.5)MM

Peers included: APA, APC, AR, BBG, CHK, CLR, COG, CPE, CRK, CRZO, CXO, DNR, DVN, ECR, EGN, EOG, EPE, EQT, FANG, GPOR, GST, HK, JONE, LPI, MRO, MTDR, MUR, NBL, NFX, OAS, PDCE, PE, PXD, QEP, REI, RICE, RRC, RSPP, SD, SGY, SM, SN, SWN, UNT, UPL, VNR, WLL, WPX, and XEC.

Source: FactSet
Accelerating Value and Derisking Inventory through JVs

**Highlights:**

- Up to $300MM over ~2 years
  - Two tranches of $160MM
  - Initial commitment of $160MM
- DrillCo type structure where Investor funds 100% of project capital for 90% WI, with CRC carried on its 10% WI
  - CRC interest reverts to 75% after target IRR is achieved
  - CRC retains early termination options
- Focus on four fields within the San Joaquin Basin
  - Kern Front, Mt. Poso, Pleito Ranch, Wheeler Ridge
- CRC operates all wells

**Highlights:**

- Up to $250MM over ~2 years
  - Two tranches of $50MM
  - Total of $100MM funded
- Investor funds 100% of project capital in exchange for a net profits interest (NPI)
  - Investor NPI interest reverts to CRC after low teens target IRR
  - CRC retains early termination options
- Current focus is in the San Joaquin Basin
- CRC operates all wells
Typical Industry JV Structure

- Based on recent industry JV deals, a typical deal structure is
  - Partner pays 80-100% Capital
  - Receives 80-100% Working Interest
  - Typical hurdle rate:
    - 10% - 20% IRR
  - Partner’s working interest once hurdle rate is achieved:
    - 5% - 25%
Dynamic Portfolio Provides Flexibility

For illustration of portfolio optionality based on normalized results per $10MM of investment and not guidance. See endnote for details on type curves. Prices for recycle ratio are $65 Brent and $3.50 NYMEX.
All economics are pre-tax. VCI range by project is summarized from ‘Type Wells by Mechanism’ in subsequent slides. Low end of range assumes $55 Brent and high end assumes $75 Brent and $3.50 NYMEX.

1.3 VCI implies $1.30 of PV-10 for every $1 invested
Greenfield Steamflood Type Pattern

* Information is for a steamflood pattern assuming 3 producers per 1 injector and is fully burdened with new steam generator infrastructure costs of $900K per pattern. At low prices, new steam generation infrastructure is not added to the project. See endnotes for important information about our type curves.
Waterflood – New Pattern Composite Type Well

* Capital cost is fully burdened with facilities, injectors and tie-ins. Assumes 5-spot pattern with a 1:1 producer to injector ratio. See endnote for important information about our type curves.
Waterflood – Redevelopment Type Well

* Capital cost is fully burdened with facilities, injectors and tie-ins
** A majority of locations are subject to PSCs, which have a 49% NPI. For NPV calculation, this can be modeled as 49% WI/NRI. For Production Rate, Net/Gross ratio is typically 75% when including cost recovery barrels.

See endnote for important information about our type curves.

<table>
<thead>
<tr>
<th>PARAMETERS</th>
<th>Operating Expense</th>
<th>Capital Cost*</th>
<th>Total EUR (MBOE)</th>
<th>Peak Rate (BOEPD)</th>
<th>Drilling Time (days)</th>
<th>Royalty</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$19/BOE</td>
<td>$1.8MM</td>
<td>165</td>
<td>120</td>
<td>14</td>
<td>PSC**</td>
</tr>
</tbody>
</table>

350 Near Term Growth Plan Locations
Primary Type Well – Deeper Horizons

PARAMETERS

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Expense</td>
<td>$10/BOE</td>
</tr>
<tr>
<td>Capital Cost*</td>
<td>$5.0MM</td>
</tr>
<tr>
<td>Total EUR (MBOE)</td>
<td>430</td>
</tr>
<tr>
<td>Peak Rate (BOEPD)</td>
<td>360</td>
</tr>
<tr>
<td>Drilling Time (days)</td>
<td>30</td>
</tr>
<tr>
<td>Royalty</td>
<td>12%</td>
</tr>
</tbody>
</table>

* Capital cost includes drilling, completion, and tie-ins. Does not include 450 shallow (<5,000 ft) locations with costs under $1.5 MM/well and with similar economics. See endnote for important information about our type curves.

150 Near Term Growth Plan Locations
California Shale Type Well

**New Pool Type Curve**

- Gunslinger Actuals
- Rose/N. Shafter Actuals
- Elk Hills Actuals
- Infill Shale Curve

**Operating Expense**
- New Pool: $10/BOE
- Infill: $8/BOE

**Capital Cost**
- New Pool: $5.0MM
- Infill: $2.5MM

**Total EUR (MBOE)**
- New Pool: 765
- Infill: 220

**Peak Rate (BOEPD)**
- New Pool: 500
- Infill: 143

**Drilling Time (days)**
- New Pool: 30
- Infill: 20

**Average Royalty**
- New Pool: 13%
- Infill: 13%

---

**50 Near Term Growth Plan Locations (Split Evenly)**

<table>
<thead>
<tr>
<th>VCI</th>
<th>Infill</th>
<th>New Pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>$50</td>
<td>1.2</td>
<td>1.7</td>
</tr>
<tr>
<td>$55</td>
<td>1.3</td>
<td>1.9</td>
</tr>
<tr>
<td>$60</td>
<td>1.4</td>
<td>2.0</td>
</tr>
</tbody>
</table>

*Capital cost includes drilling, completion, and tie-ins. See endnote for important information about our type curves.
California Operator of Choice

- Proven coexistence with sensitive environmental receptors
- ~4 billion gallons of water supplied to agriculture in 2016
- Excellence in safety and mechanical integrity
- Recognized by national safety and environmental organizations

WATER MANAGED IN CRC’s OPERATIONS

- 94% Fresh Water
- 3% Non-Fresh Water
- 3% Produced Water
## 4Q17 Guidance

### Anticipated Realizations Against the Prevailing Index Prices for 4Q17

<table>
<thead>
<tr>
<th></th>
<th></th>
<th>to</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>90%</td>
<td>94% of Brent</td>
</tr>
<tr>
<td>NGLs</td>
<td>69%</td>
<td>73% of Brent</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>96%</td>
<td>100% of NYMEX</td>
</tr>
</tbody>
</table>

### Production, Capital and Income Statement Guidance

<table>
<thead>
<tr>
<th></th>
<th></th>
<th>to</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Production</strong></td>
<td>125</td>
<td>130 Mboe/d</td>
</tr>
<tr>
<td><strong>Capital</strong></td>
<td>$110</td>
<td>$130 million</td>
</tr>
<tr>
<td><strong>Production Costs</strong></td>
<td>$18.75</td>
<td>$19.75 per Boe</td>
</tr>
<tr>
<td><strong>G&amp;A</strong></td>
<td>$5.35</td>
<td>$5.65 per Boe</td>
</tr>
<tr>
<td><strong>DD&amp;A</strong></td>
<td>$11.60</td>
<td>$11.90 per Boe</td>
</tr>
<tr>
<td><strong>Taxes other than on income</strong></td>
<td>$33</td>
<td>$37 million</td>
</tr>
<tr>
<td><strong>Exploration expense</strong></td>
<td>$6</td>
<td>$10 million</td>
</tr>
<tr>
<td><strong>Interest expense</strong></td>
<td>$82</td>
<td>$86 million</td>
</tr>
<tr>
<td><strong>Cash Interest</strong></td>
<td>$141</td>
<td>$145 million</td>
</tr>
<tr>
<td><strong>Income tax expense rate</strong></td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td><strong>Cash tax rate</strong></td>
<td>0%</td>
<td></td>
</tr>
</tbody>
</table>
End Notes

1 Current CRC estimate of reserves value as of December 31, 2016. Includes field-level operating expenses and G&A. Assumes $3.30/Mcf NYMEX.

2 Surface & Minerals reflect the estimated value of undeveloped surface and fee interests.

3 Reflects the value of facilities and midstream assets at 50% of estimated replacement value. This discount is estimated to exceed the burden on reserves that would be incurred if assets were monetized.

4 Unproved inventory comprises risked probable and possible reserves and contingent and prospective resources. Contingent and prospective resources consist of volumes identified through life-of-field planning efforts to date.

5 Calculated using September 30, 2017 debt at par and market cap as of November 3, 2017.

Type Curve Note: Each field-specific type well curve represents an average of the historical results of multiple projects over the prior four-year time period. Drive mechanism type curves are the weighted average of the field-specific curves related to the projects chosen for our near-term growth plan. Type curves represent management’s estimates of future results and are subject to project selection and other variables. Our type well curves are prepared for purposes of modeling overall results of our near-term growth program and are not useful for purpose of benchmarking any individual well or pattern performance. Actual results are expected to vary depending on which projects are specifically developed.