## NEWS RELEASE

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# California Resources Corporation Announces First Quarter 2018 Results

LOS ANGELES, May 3, 2018 - California Resources Corporation (NYSE:CRC), an independent California-based oil and gas exploration and production company, today reported a net loss attributable to common stock (CRC net loss) of $2 million, or $0.05 per diluted share, for the first quarter of 2018. Adjusted net income[1] for the first quarter of 2018 was $8 million, or $0.18 per diluted share.

Adjusted EBITDAX[1] for the first quarter of 2018 was $250 million and cash provided by operating activities was $200 million. Capital investments were $139 million.

**Quarterly Highlights Include:**

- Produced 123,000 BOE per day, above the midpoint of the guidance range
- Invested capital of $139 million
- Drilled 44 wells with internally funded capital and 30 wells with joint venture (JV) capital
- Generated adjusted EBITDAX[1] of $250 million, reflecting an adjusted EBITDAX margin[1] of 41%

**2018 Outlook:**

- Increased 2018 capital budget to a range of $550 million to $600 million, with approximately $100 to $150 million funded by JV partners BSP and Macquarie
- Incremental capital directed to drilling, workover and facilities projects in the San Joaquin, Los Angeles and Ventura basins
- Second quarter of 2018 production guidance of 131,000 to 136,000 BOE per day, reflecting a 2,000 BOE per day negative impact due to production sharing contracts (PSC) effects utilizing first quarter of 2018 price levels
- Second quarter of 2018 production forecast is flat with first quarter of 2018 production levels, adjusted for the PSC effect and excluding the Elk Hills acquisition production
- Production from Elk Hills acquired interests for second quarter of 2018 projected at approximately 11,600 BOE per day, reflecting transition mechanics.
- In the third quarter of 2018, the Company expects approximately 12,000 BOE per day contribution from acquired Elk Hills interests

Todd A. Stevens, CRC's President and Chief Executive Officer, said, "With our midstream joint venture and recent transaction to consolidate our interest in our flagship Elk Hills field, CRC is off to a strong start in 2018. Supported by increasing cash flow and a clear runway to execute, we are well-positioned for a mid-cycle commodity price environment. As our first quarter results and second quarter guidance show, we have confidence that we have arrested the decline in our production, excluding PSC impacts. We increased our capital program to target the next phase of development and further delineate growth areas. We will see associated production growth later this year and into 2019. Our top priorities remain centered on value-oriented growth and cash margin expansion, as we allocate capital to capture the full potential of our assets and deliver lasting value for our shareholders."

**First Quarter 2018 Results**

For the first quarter of 2018, the CRC net loss was $2 million, or $0.05 per diluted share, and adjusted net income[1] was $8 million, or $0.18 per diluted share. Adjusted net income[1] excluded $7 million of non-cash derivatives losses and a $2 million charge for severance costs.

Total daily production volumes averaged 123,000 barrels of oil equivalent (BOE) per day for the first quarter of 2018. Compared to the fourth quarter of 2017, first quarter production was reduced by 2,400 BOE per day due to PSC effects from higher prices. Excluding PSC effects, sequential production was essentially flat. For the first quarter of 2018, oil volumes averaged 77,000 barrels per day, NGL volumes averaged 16,000 barrels per day and gas volumes averaged 182,000 thousand cubic feet (MCF) per day. First quarter results reflect a residual 400 BOE per day negative impact due to the 2017 California wildfires and subsequent mudslides. The impact of PSC effect relative to guidance was a small negative amount.

Realized crude oil prices, including the effect of settled hedges, increased by $12.53 per barrel in the first quarter of 2018 to $62.77 per barrel from the prior year comparable period. Settled hedges decreased realized crude oil prices by $4.49 per barrel. Average realized NGL prices continued to be strong and registered $43.13 per barrel, reflecting a realized price that was 64% of Brent prices. Realized natural gas prices were $2.81 per MCF.

Production costs for the first quarter of 2018 were $212 million, essentially flat with the $211 million in the first quarter of 2017. On a per unit basis, first quarter production costs of $19.08 per BOE were higher than the comparable prior year period of $17.70 per BOE, due to lower production. First quarter unit production costs were lower than previously disclosed guidance levels, reflecting continued cost reductions and efficiency, as well as timing of activities, across most cost categories. The industry practice for reporting PSCs can result in higher production costs per barrel as gross field operating costs are matched with net production. Excluding the PSC effects, per unit production costs[1] for the first quarter of 2018 would have been $17.47. General and administrative (G&A) expenses were $63 million for the first quarter of 2018, compared to $66 million in the fourth quarter of 2017 and consistent with the prior year comparable period. These costs were also lower than the guidance range for the period due to the timing of certain corporate expenses.

CRC reported taxes other than on income of $38 million, $5 million higher than the prior year period primarily due to the increase in market prices for greenhouse gas allowances, among other factors. Exploration expense of $8 million for the first quarter of 2018 increased $2 million from the prior year comparable period, demonstrating the Company's commitment to the exploration opportunities within its large asset portfolio.

Capital investment in the first quarter of 2018 totaled $139 million, excluding JV capital. Approximately $94 million was directed to drilling and capital workovers.

Cash provided by operating activities was $200 million. CRC generated free cash flow[1] of $61 million in the first quarter of 2018.

**Operational Update**

CRC operated an average of nine rigs during the first quarter of 2018 and drilled 74 wells with CRC and JV capital, consisting of 72 development wells (55 steamflood, 10 waterflood, one primary and six unconventional) and two exploration wells. Steamfloods and waterfloods have different production profiles and longer response times than typical conventional wells and, as a result, the full production contribution may not be experienced in the same year that the well is drilled. In the San Joaquin basin, CRC operated seven rigs and produced approximately 87,000 BOE per day for the first quarter. The Los Angeles basin had one rig directed toward waterflood projects, and contributed 24,000 BOE per day of production in the first quarter of 2018. Ventura basin activity included one rig focused on conventional projects and produced approximately 6,000 BOE per day for the first quarter of 2018. The California wildfires in December 2017 and subsequent mudslides negatively impacted Ventura basin production by approximately 400 BOE per day in the first quarter of 2018, in line with expectations incorporated into the Company's previous guidance. The related production effects have been resolved and should not affect second quarter production. CRC continues to focus on oil weighted projects, with no development drilling activity in the Sacramento basin at this time.

**Elk Hills Transaction**

As previously announced, on April 9, 2018 CRC consolidated its interest in the 47,000-acre Elk Hills field by acquiring the remaining working, surface and mineral interests from its long-time partner Chevron. CRC paid cash consideration of $460 million and issued 2.85 million of common shares for the assets. The effective date of the transaction was April 1, 2018. The acquisition includes Chevron's non-operated working interests ranging between 20% and 22% in different producing horizons. In the fourth quarter of 2017, the acquired interests produced an average of 12,700 BOE per day with 46% oil and 9% natural gas liquids. CRC expects to realize the full incremental production in the third quarter of 2018 after the effect of the initial transitional mechanics abate. The Company estimates these additional interests would have added approximately 64 million BOE of proved reserves at year-end 2017 of which approximately 75% are considered proved developed. Over the next two years, CRC estimates up to $20 million of annualized savings as it streamlines production facilities, operations and processes, and leverages Elk Hills' substantial infrastructure.

## 2018 Capital Budget

In conjunction with improved commodity prices and additional cash flow expected from the acquisition of the Elk Hills interests and synergies, CRC increased its 2018 capital program to a range from $550 million to $600 million, which includes approximately $100 to $150 million in JV capital. This is an increase from its previously stated budget range of $500 million to $550 million. The incremental investment should increase second half 2018 production over first half 2018 levels with a more meaningful effect in 2019. The additional capital will primarily be deployed to drilling, workover and facilities in the San Joaquin, Los Angeles and Ventura basins. Further, CRC expects funding of a third tranche of the BSP capital in the second quarter of 2018.

## Debt Reduction Update

CRC continues to show its commitment to strengthening the balance sheet. In April, CRC repurchased a total of $95 million in aggregate principal amount of the Company's second lien notes for $79 million in cash.

## Borrowing Base Redetermination

Effective May 1, 2018, CRC's borrowing base under its 2014 Credit Agreement was reaffirmed at $2.3 billion.

## Hedging Update

CRC continues to opportunistically seek hedging transactions to protect its cash flow, operating margins and capital program while maintaining adequate liquidity. In the first and second quarters of 2019, CRC hedged approximately 35,000 and 20,000 barrels per day, respectively. The hedges generally form an effective floor at around $63 Brent with a portion of the hedge volumes continuing to provide CRC upside at prices above $67. For the third quarter of 2019, the Company has hedged 10,000 barrels per day providing an effective floor at $65 Brent or Brent plus $15 at prices below $50 Brent. At prices above $65 Brent, CRC continues to receive Brent pricing. See Attachment 8 for more details.

[1] See Attachment 3 for explanations of how CRC calculates and uses the non-GAAP measures of adjusted EBITDAX, adjusted EBITDAX margin, PV-10, free cash flow, production costs (excluding the effects of production sharing-type contracts (PSC)) and adjusted net income (loss), and for reconciliations of the foregoing to their nearest GAAP measure as applicable.

## Conference Call Details

To participate in today's conference call scheduled for 5:00 P.M. Eastern Daylight Time, either dial (877) 328-5505 (International calls please dial +1 (412) 317-5421) or access via webcast at www.crc.com, fifteen minutes prior to the scheduled start time to register. Participants may also pre-register for the conference call at http://dpregister.com/10118433. A digital replay of the conference call will be archived for approximately 30 days and supplemental slides for the conference call will be available online in the Investor Relations section of www.crc.com.

**About California Resources Corporation**

California Resources Corporation is the largest oil and natural gas exploration and production company in California on a gross-operated basis. The Company operates its world-class resource base exclusively within the State of California, applying complementary and integrated infrastructure to gather, process and market its production. Using advanced technology, California Resources Corporation focuses on safely and responsibly supplying affordable energy for California by Californians.

**Forward-Looking Statements**

This presentation contains forward-looking statements that involve risks and uncertainties that could materially affect CRC's expected results of operations, liquidity, cash flows and business prospects. Such statements include those regarding the Company's expectations as to 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 value creation index (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 CRC believes the assumptions or bases underlying its expectations are reasonable and makes them in good faith, they almost always vary from actual results, sometimes materially. Factors (but not necessarily all the factors) that could cause results to differ include:

- commodity price changes
- debt limitations on its 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 its 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 CRC's Annual Report on Form 10-K available on its website at www.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 the Company undertakes 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.

**Contacts:**

Scott Espenshade (Investor Relations)
818-661-6010
Scott.Espenshade@crc.com

Margita Thompson (Media)
818-661-6005
Margita.Thompson@crc.com

**SUMMARY OF RESULTS**

| ($ and shares in millions, except per share amounts) | First Quarter 2018 | First Quarter 2017 |
|---|---|---|
| **Statement of Operations Data:** | | |
| **Revenues and Other** | | |
| Oil and gas sales | **$ 575** | $ 487 |
| Net derivative (losses) gains | **(38)** | 73 |
| Other revenue | **72** | 30 |
| Total revenues and other [(a)] | **609** | 590 |
| **Costs and Other** | | |
| Production costs | **212** | 211 |
| General and administrative expenses | **63** | 63 |
| Depreciation, depletion and amortization | **119** | 140 |
| Taxes other than on income | **38** | 33 |
| Exploration expense | **8** | 6 |
| Other expenses, net [(a)] | **61** | 22 |
| Total costs and other | **501** | 475 |
| **Operating Income** | **108** | 115 |
| **Non-Operating (Loss) Income** | | |
| Interest and debt expense, net | **(92)** | (84) |
| Net gains on early extinguishment of debt | **—** | 4 |
| Gains on asset divestitures | **—** | 21 |
| Other non-operating expenses | **(7)** | (4) |
| **Income Before Income Taxes** | **9** | 52 |
| Income tax benefit | **—** | — |
| **Net Income** | **9** | 52 |
| Net (income) loss attributable to noncontrolling interest | **(11)** | 1 |
| **Net (Loss) Income Attributable to Common Stock** | **$ (2)** | $ 53 |
| Net (loss) income attributable to common stock per share - basic | **$ (0.05)** | $ 1.23 |
| Net (loss) income attributable to common stock per share - diluted | **$ (0.05)** | $ 1.22 |
| Adjusted net income (loss) | **$ 8** | $ (43) |
| Adjusted net income (loss) per diluted share | **$ 0.18** | $ (1.02) |
| Weighted-average common shares outstanding - basic | **44.2** | 42.3 |
| Weighted-average common shares outstanding - diluted | **44.2** | 42.6 |
| Adjusted EBITDAX | **$ 250** | $ 200 |
| Effective tax rate | **0%** | 0% |

(a) We adopted the new revenue recognition standard on January 1, 2018 which required certain sales related costs to be reported as expense as opposed to being netted against revenue. The adoption of this standard does not affect net income. Results for reporting periods beginning after January 1, 2018 are presented under the new accounting standard while prior periods are not adjusted and continue to be reported under accounting standards in effect for the prior period. The increase in total revenues and other for the three months ended March 31, 2018 was $42 million. Under prior accounting standards total revenues and other would have been $567 million and other expenses, net would have been $19 million.

| **Cash Flow Data:** | First Quarter 2018 | First Quarter 2017 |
|---|---|---|
| Net cash provided by operating activities | **$ 200** | $ 133 |
| Net cash used in investing activities | **$ (138)** | $ — |
| Net cash provided (used) by financing activities | **$ 412** | $ (95) |

**Balance Sheet Data:**

| | **March 31, 2018** | December 31, 2017 |
|---|---|---|
| Cash and cash equivalents | **$ 494** | $ 20 |
| Total current assets | **$ 949** | $ 483 |
| Total property, plant and equipment, net | **$ 5,714** | $ 5,696 |
| Current maturities of long-term debt | **$ —** | $ — |
| Total current liabilities | **$ 806** | $ 732 |
| Long-term debt, principal amount | **$ 4,941** | $ 5,306 |
| Mezzanine equity | **$ 724** | $ — |
| Total equity | **$ (654)** | $ (720) |
| | | |
| Outstanding shares as of | **45.3** | 42.9 |

**PRODUCTION STATISTICS**

| **Net Oil, NGLs and Natural Gas Production Per Day** | First Quarter **2018** | First Quarter 2017 |
|---|---|---|
| **Oil (MBbl/d)** | | |
| San Joaquin Basin | **49** | 54 |
| Los Angeles Basin | **24** | 27 |
| Ventura Basin | **4** | 5 |
| Sacramento Basin | **—** | — |
| Total | **77** | 86 |
| **NGLs (MBbl/d)** | | |
| San Joaquin Basin | **15** | 15 |
| Los Angeles Basin | **—** | — |
| Ventura Basin | **1** | 1 |
| Sacramento Basin | **—** | — |
| Total | **16** | 16 |
| **Natural Gas (MMcf/d)** | | |
| San Joaquin Basin | **143** | 141 |
| Los Angeles Basin | **1** | 1 |
| Ventura Basin | **7** | 8 |
| Sacramento Basin | **31** | 31 |
| Total | **182** | 181 |
| **Total Production (MBoe/d)** [(a)] | **123** | 132 |

(a) Natural gas volumes have been converted to BOE based on the equivalence of energy content between six Mcf of natural gas and one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

**NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS**

Our results of operations can include the effects of unusual, out-of-period and infrequent transactions and events affecting earnings that vary widely and unpredictably (in particular certain non-cash items such as derivatives gains and losses) in nature, timing, amount and frequency. Therefore, management uses a measure called adjusted net income (loss) which excludes those items. This measure is not meant to disassociate items from management's performance, but rather is meant to provide useful information to investors interested in comparing our performance between periods. Reported earnings are considered representative of management's performance over the long term. Adjusted net income (loss) is not considered to be an alternative to net income (loss) reported in accordance with U.S. generally accepted accounting principles (GAAP).

We define adjusted EBITDAX as earnings before interest expense; income taxes; depreciation, depletion and amortization; exploration expense; other unusual, out-of-period and infrequent items and other non-cash items. We believe adjusted EBITDAX 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. While adjusted EBITDAX is a non-GAAP measure, the amounts included in the calculation of adjusted EBITDAX were computed in accordance with GAAP. A version of this measure is a material component of certain of our financial covenants under our 2014 revolving credit facility and is provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP. Certain items excluded from adjusted EBITDAX are significant components in understanding and assessing our financial performance, such as our cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. Adjusted EBITDAX should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP.

**ADJUSTED NET INCOME (LOSS)**

The following table presents a reconciliation of the GAAP financial measure of net income (loss) attributable to common stock to the non-GAAP financial measure of Adjusted net income (loss):

| | First Quarter | |
|---|---|---|
| ($ millions, except per share amounts) | **2018** | 2017 |
| Net (loss) income attributable to common stock | **$ (2)** | $ 53 |
| Unusual, infrequent and other items: | | |
| Non-cash derivative losses (gains), excluding noncontrolling interest | **7** | (75) |
| Early retirement and severance costs | **2** | 3 |
| Gains on asset divestitures | **—** | (21) |
| Net gains on early extinguishment of debt | **—** | (4) |
| Other, net | **1** | 1 |
| Total unusual and infrequent items | **10** | (96) |
| Adjusted net income (loss) | **$ 8** | $ (43) |
| Net (loss) income attributable to common stock per share - basic | **$ (0.05)** | $ 1.23 |
| Net (loss) income attributable to common stock per share - diluted | **$ (0.05)** | $ 1.22 |
| Adjusted net income (loss) per diluted share | **$ 0.18** | $ (1.02) |

**DERIVATIVES GAINS AND LOSSES**

| | First Quarter | |
|---|---|---|
| ($ millions) | **2018** | 2017 |
| Non-cash derivative (losses) gains, excluding noncontrolling interest | **$ (7)** | $ 75 |
| Non-cash derivative losses for noncontrolling interest | **—** | (1) |
| Net payments on settled derivatives | **(31)** | (1) |
| Net derivative (losses) gains | **$ (38)** | $ 73 |

**FREE CASH FLOW**

| ($ millions) | First Quarter 2018 | 2017 |
|---|---|---|
| Net cash provided by operating activities | **$ 200** | $ 133 |
| Capital investment | **(139)** | (50) |
| Free cash flow | **61** | 83 |
| Changes in capital accruals | **5** | 17 |
| Capitalized interest | **(1)** | — |
| Free cash flow, after working capital | **65** | 100 |
| BSP funded capital investment | **—** | 15 |
| Free cash flow, after working capital excluding BSP funded capital | **$ 65** | $ 115 |

**ADJUSTED EBITDAX**

The following tables present a reconciliation of the GAAP financial measures of net income (loss) attributable to common stock and net cash provided (used) by operating activities to the non-GAAP financial measure of adjusted EBITDAX.

| ($ millions) | First Quarter 2018 | 2017 |
|---|---|---|
| Net income | **$ 9** | $ 52 |
| Interest and debt expense, net | **92** | 84 |
| Depreciation, depletion and amortization | **119** | 140 |
| Exploration expense | **8** | 6 |
| Unusual, infrequent and other items (b) | **10** | (96) |
| Other non-cash items | **12** | 14 |
| Adjusted EBITDAX (A) | **$ 250** | $ 200 |
| | | |
| Net cash provided by operating activities | **$ 200** | $ 133 |
| Cash interest | **61** | 44 |
| Exploration expenditures | **6** | 5 |
| Changes in operating assets and liabilities | **(18)** | 17 |
| Other, net | **1** | 1 |
| Adjusted EBITDAX (A) | **$ 250** | $ 200 |

(b) See Adjusted Net Income (Loss) reconciliation.

**ADJUSTED EBITDAX MARGIN**

| ($ millions) | First Quarter 2018 | 2017 |
|---|---|---|
| Total Revenues | **$ 609** | $ 590 |
| Non-cash derivative losses (gains) | **7** | (74) |
| Adjusted revenues (B) | **$ 616** | $ 516 |
| Adjusted EBITDAX Margin (A)/(B) (c) | **41%** | 39% |

(c) See Note (a) on Attachment 1 related to our adoption of the new accounting standard related to the reporting of certain sales related costs. Under prior accounting standards our adjusted EBITDAX margin would have been 44% in the first quarter of 2018.

**PRODUCTION COSTS PER BOE**

| ($ per Boe) | First Quarter | |
|---|---|---|
| | **2018** | 2017 |
| Production Costs | **$ 19.08** | $ 17.70 |
| Costs attributable to PSC type contracts | **(1.61)** | (1.04) |
| Production Costs, excluding the effects of PSC type contracts | **$ 17.47** | $ 16.66 |

**ADJUSTED NET INCOME / (LOSS) VARIANCE ANALYSIS**

($ millions)

| | | |
|---|---|---|
| **2017 1st Quarter Adjusted Net Loss** | **$** | **(43)** |
| Price - Oil | | 100 |
| Price - NGLs | | 13 |
| Price - Natural Gas | | (1) |
| Volume | | (45) |
| Production cost | | (1) |
| DD&A rate | | 14 |
| Exploration expense | | (2) |
| Interest expense | | (8) |
| All others | | (19) |
| **2018 1st Quarter Adjusted Net Income** | **$** | **8** |

**CAPITAL INVESTMENTS**

| ($ millions) | First Quarter 2018 | 2017 |
|---|---|---|
| Internally Funded Capital Investments | **$ 139** | $ 35 |
| BSP Funded Capital | **—** | 15 |
| Consolidated Reported Capital | **$ 139** | $ 50 |
| MIRA Funded Capital | **22** | — |
| Total Capital Program | **$ 161** | $ 50 |

**NONCONTROLLING INTEREST DETAIL**

| ($ millions) | First Quarter 2018 | 2017 |
|---|---|---|
| **Distributions to noncontrolling interest** | | |
| BSP Joint Venture | **$ 13** | $ — |
| Ares Joint Venture | **5** | — |
| Total | **$ 18** | $ — |

**PRICE STATISTICS**

| | First Quarter | |
|---|---|---|
| | **2018** | 2017 |
| **Realized Prices** | | |
| Oil with hedge ($/Bbl) | **$ 62.77** | $ 50.24 |
| Oil without hedge ($/Bbl) | **$ 67.26** | $ 50.40 |
| NGLs ($/Bbl) | **$ 43.13** | $ 34.33 |
| Natural gas ($/Mcf) [(a)] | **$ 2.81** | $ 2.90 |
| **Index Prices** | | |
| Brent oil ($/Bbl) | **$ 67.18** | $ 54.66 |
| WTI oil ($/Bbl) | **$ 62.87** | $ 51.91 |
| NYMEX gas ($/MMBtu) | **$ 2.87** | $ 3.26 |
| **Realized Prices as Percentage of Index Prices** | | |
| Oil with hedge as a percentage of Brent | **93%** | 92% |
| Oil without hedge as a percentage of Brent | **100%** | 92% |
| Oil with hedge as a percentage of WTI | **100%** | 97% |
| Oil without hedge as a percentage of WTI | **107%** | 97% |
| NGLs as a percentage of Brent | **64%** | 63% |
| NGLs as a percentage of WTI | **69%** | 66% |
| Natural gas as a percentage of NYMEX [(a)] | **98%** | 89% |

(a) See Note (a) on Attachment 1 related to our adoption of the new accounting standard related to the reporting of certain sales related costs. Under prior accounting standards our natural gas realized price would have been $2.53 per Mcf and our realized price as a percentage of NYMEX would have been 88% in the first quarter of 2018.

**FIRST QUARTER DRILLING ACTIVITY**

| Wells Drilled (Gross) | San Joaquin Basin | Los Angeles Basin | Ventura Basin | Sacramento Basin | Total |
|---|---|---|---|---|---|
| **Development Wells** | | | | | |
| Primary | 1 | — | — | — | 1 |
| Waterflood | 5 | 5 | — | — | 10 |
| Steamflood | 55 | — | — | — | 55 |
| Unconventional | 6 | — | — | — | 6 |
| Total | 67 | 5 | — | — | 72 |
| **Exploration Wells** | | | | | |
| Primary | 1 | — | 1 | — | 2 |
| Waterflood | — | — | — | — | — |
| Steamflood | — | — | — | — | — |
| Unconventional | — | — | — | — | — |
| Total | 1 | — | 1 | — | 2 |
| **Total Wells** [(a)] | 68 | 5 | 1 | — | 74 |
| CRC Wells Drilled | 38 | 5 | 1 | — | 44 |
| MIRA Wells Drilled | 30 | — | — | — | 30 |

[(a)] Includes steam injectors and drilled but uncompleted wells, which would not be included in the SEC definition of wells drilled.

**HEDGES - CURRENT**

| | 2Q 2018 | 3Q 2018 | 4Q 2018 | 1Q 2019 | 2Q 2019 | 3Q 2019 | 4Q 2019 | FY 2020 |
|---|---|---|---|---|---|---|---|---|
| **Crude Oil** | | | | | | | | |
| Sold Calls: | | | | | | | | |
| Barrels per day | 6,168 | 6,127 | 16,086 | 16,057 | 6,023 | 991 | 961 | 503 |
| Weighted-average Brent price per barrel | $60.24 | $60.24 | $58.91 | $65.75 | $67.01 | $60.00 | $60.00 | $60.00 |
| Purchased Calls: | | | | | | | | |
| Barrels per day | — | — | — | 2,000 | — | — | — | — |
| Weighted-average Brent price per barrel | $— | $— | $— | $71.00 | $— | $— | $— | $— |
| Purchased Puts: | | | | | | | | |
| Barrels per day | 1,168 | 6,127 | 1,086 | 29,057 | 21,023 | 10,991 | 961 | 503 |
| Weighted-average Brent price per barrel | $45.83 | $61.47 | $45.85 | $60.86 | $62.40 | $63.27 | $45.85 | $43.91 |
| Sold Puts: | | | | | | | | |
| Barrels per day | 29,000 | 24,000 | 19,000 | 30,000 | 15,000 | 10,000 | — | — |
| Weighted-average Brent price per barrel | $45.00 | $46.04 | $45.00 | $49.17 | $50.00 | $50.00 | $— | $— |
| Swaps: | | | | | | | | |
| Barrels per day | 44,350 | 19,000 | 19,000 | 7,000 | — | — | — | — |
| Weighted-average Brent price per barrel | $60.00 | $60.13 | $60.13 | $67.71 | $— | $— | $— | $— |

A small portion of the derivatives in the table above were entered into by the BSP JV, including all of the 2020 positions. The BSP JV also entered into natural gas swaps for insignificant volumes for periods through July 2020.

Certain of our counterparties have options to increase swap volumes by up to:
- 29,000 barrels per day at a weighted-average Brent price of $60.50 for the second half of 2018 and
- 5,000 barrels per day at a weighted-average Brent price of $70.00 for the first quarter of 2019.

**2018 SECOND QUARTER GUIDANCE**

| **Anticipated Realizations Against the Prevailing Index Prices for Q2 2018** [a] | |
|---|---|
| Oil | 94% to 98% of Brent |
| NGLs | 52% to 56% of Brent |
| Natural Gas | 81% to 85% of NYMEX |

| **2018 Second Quarter Production, Capital and Income Statement Guidance** | |
|---|---|
| Production at current prices [b] | 131 to 136 MBOE per day |
| Production at average Q1 2018 Brent of $67 | 133 to 138 MBOE per day |
| Capital | $165 million to $185 million |
| Production costs at current prices [b] | $18.10 to $19.60 per BOE |
| Production costs at average Q1 2018 Brent of $67 | $17.90 to $19.40 per BOE |
| Adjusted general and administrative expenses [b] & [c] | $6.45 to $6.75 per BOE |
| Depreciation, depletion and amortization [b] | $10.30 to $10.60 per BOE |
| Taxes other than on income | $34 million to $38 million |
| Exploration expense | $7 million to $11 million |
| Interest expense [d] | $91 million to $95 million |
| Cash Interest [d] | $150 million to $154 million |
| Income tax expense rate | 0% |
| Cash tax rate | 0% |

| **Pre-tax 2018 Second Quarter Price Sensitivities** [e] | |
|---|---|
| $1 change in Brent index - Oil [f] | $2.2 million |
| $1 change in Brent index - NGLs | $0.8 million |
| $0.50 change in NYMEX - Gas | $4.3 million |

(a) Realizations exclude hedge effects.

(b) Based on assumed average Q2 2018 Brent price of $74.

(c) Our long-term incentive compensation program for non-executive employees are stock based but payable in cash. Accounting rules require that we adjust the cumulative liability for all vested but yet unpaid awards under these programs to the amount that would be paid using our stock price as of the end of each quarter. Therefore, in addition to the normal pro-rata vesting expense associated with these programs, our quarterly G&A expense includes this cumulative adjustment. Our stock price at March 31, 2018 was $17.15 per share. Our guidance reflects what the effect of such cumulative adjustment will be assuming that our current stock price of approximately $25 per share will prevail at the end of the second quarter. Only about 1/3 of such cumulative adjustment would result in a cash liability in the same year as the adjustment because of the pro-rata three year vesting of our incentive compensation programs.

(d) Interest expense includes cash interest, original issue discount and amortization of deferred financing costs as well as the deferred gain that resulted from the December 2015 debt exchange. Cash interest for the quarter is higher than interest expense due to the timing of interest payments.

(e) Due to our tax position there is no difference between the impact on our income and cash flows.

(f) Amount reflects the sensitivity with respect to unhedged barrels at a Brent index price exceeding $60.00 per barrel and includes the effect of production sharing type contracts at our Wilmington field operations in Long Beach.