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# NEWS RELEASE

## California Resources Corporation Announces Fourth Quarter 2019 and Full Year Results

LOS ANGELES, February 26, 2020 - 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 of $67 million, or $1.36 per diluted share, for the fourth quarter of 2019. Adjusted net income[1] for the fourth quarter of 2019 was $36 million, or $0.73 per diluted share. For the full year of 2019, CRC reported a net loss attributable to common stock of $28 million, or $0.57 per diluted share. Adjusted net income[1] for the full year of 2019 was $70 million, or $1.40 per diluted share. Operational and financial highlights for the fourth quarter and full year of 2019 were as follows:

**Quarterly Highlights**

- Reported adjusted EBITDAX[1] of $308 million; adjusted EBITDAX margin[1] of 45%; net cash provided by operating activities of $136 million; free cash flow[1] of $74 million after internally funded capital
- Implemented a more efficient organizational design, resulting in anticipated ongoing annual cost savings of approximately $50 million with slightly more than 50% in general and administrative (G&A) expenses and the remainder in production costs
- Delivered average net production of 123,000 barrels of oil equivalent (BOE) per day including 76,000 barrels per day of oil
- Gross-operated field production, which includes production attributable to our JV partners, was 141,000 BOE per day, of which 91,000 barrels per day was oil
- Invested $146 million of total capital, including $62 million of internally funded capital
- Drilled 104 wells in total, including 95 wells in the San Joaquin basin and 9 wells in the Los Angeles basin
- Repurchased $23 million face value of Second Lien Notes for $7 million

**Full Year Highlights**

- Reduced net debt to below $5.0 billion, with a net debt/adjusted EBITDAX[1] ratio of 4.3
- Reported adjusted EBITDAX[1] of $1,142 million and an adjusted EBITDAX margin[1] of 41%
- Delivered free cash flow after internally funded capital[1] of $269 million and net cash provided by operating activities of $676 million
- Produced an average of 128,000 BOE per day on a net basis including 80,000 barrels per day of oil
- Drilled 294 wells, including 126 wells with internally funded capital

- Invested $612 million of total capital, including internally funded capital of $407 million, of which $302 million was directed to drilling and workovers
- Entered into a development joint venture with Alpine Energy Capital, LLC ("Alpine") to develop CRC's flagship Elk Hills field
- Secured a credit agreement amendment to provide future flexibility in connection with potential royalty transactions

Todd A. Stevens, CRC's President and Chief Executive Officer, commented, “We are extremely proud that we reduced our outstanding net debt at year end below $5 billion. We believe our announced exchange transaction could reduce our debt by almost $1 billion and is one of several steps moving towards our target leverage ratio below 3x. In 2019, we received strong confirmation of our ESG and operational efforts, including earning a Leadership Level ranking of A- on our climate disclosure from CDP and achieving a noteworthy safety record of no recordable injuries among our employees during the year.”

Stevens continued, “Our VCI metric instills capital discipline and provides for consistent and effective capital allocation. In 2019, we advanced CRC’s capital investment plans by entering into our third major development joint venture, with Alpine Energy Capital committing up to $500 million of investments in our flagship Elk Hills field. We also increased our adjusted EBITDAX margins in 2019 for the third year in a row by optimizing our operations and consolidating our organization.”

“Further, our decision to utilize more JV capital in the fourth quarter instead of internally funded capital, plus impacts from power outages and fires, led CRC’s net production to the low end of our production guidance. We are entering 2020 with an internally funded capital program of $100 to $300 million, which we will adjust as warranted based on market conditions. We expect our JV capital program in Elk Hills will increase our total capital program by $160 to $200 million to support a total 2020 capital program of approximately $260 to $500 million.”

**<u>Fourth Quarter 2019 Results</u>**

For the fourth quarter of 2019, CRC reported a net loss attributable to common stock (CRC net loss) of $67 million, or $1.36 per diluted share, compared to net income attributable to common stock of $346 million, or $7.00 per diluted share, for the same period of 2018. Adjusted net income[1] for the fourth quarter of 2019 was $36 million, or $0.73 per diluted share, compared to $26 million, or $0.53 per diluted share, for the same period in 2018. Fourth quarter 2019 adjusted net income[1] excluded a net gain of $18 million on debt repurchases, non-cash losses on commodity derivatives of $67 million, $45 million for severance and termination benefits and other losses of $9 million, net, for other unusual and infrequent items. Fourth quarter 2018 adjusted net income[1] excluded $295 million of non-cash derivative gains on commodity contracts, a $6 million non-cash derivative loss from interest-rate contracts and a net gain of $31 million on debt repurchases.

Adjusted EBITDAX[1] for the fourth quarter of 2019 was $308 million and cash provided by operating activities was $136 million.

Total daily net production volumes decreased 10% year-over-year, from 136,000 BOE per day for the fourth quarter of 2018 to 123,000 BOE per day for the fourth quarter of 2019. The decrease over the same prior-year period was due to the Lost Hills divestiture, lower capital investment, power outages and other factors. The Lost Hills divestiture reduced our fourth quarter 2019 production by approximately 2,000 BOE per day compared to the same quarter of 2018. Oil volumes in the fourth quarter of 2019 averaged 76,000 barrels per day, NGL volumes averaged 15,000 barrels per day and natural gas volumes averaged 190 million cubic feet per day.

Despite lower Brent index prices, our realized crude oil prices, including the effect of settled hedges, increased by $10.24 per barrel from $59.97 in the fourth quarter of 2018 to $70.21 per barrel in the fourth quarter of 2019. In the fourth quarter of 2019, hedge settlements increased our realized crude oil prices by $5.99 per barrel compared to a reduction of $6.15 per barrel in the same prior-year period. Realized NGL prices were $33.81 per barrel, down $9.75 per barrel over the prior-year period as local and national markets continued to experience excess domestic supply coupled with weaker demand due to Los Angeles and Bay area refinery downtimes. Realized natural gas prices were $3.00 per thousand cubic feet (Mcf) for the fourth quarter of 2019, $0.77 per Mcf lower than the same prior-year period due to milder winter temperatures across the U.S. and fewer infrastructure constraints within local California markets in 2019 compared to 2018.

Production costs for the fourth quarter of 2019 were $211 million, compared to $233 million for the fourth quarter of 2018. The decrease was primarily due to cost savings from our workforce reduction, the Lost Hills divestiture and lower downhole maintenance activity, partially offset by higher energy prices. On a per barrel basis, for the same comparative periods, production costs were $18.67 and $18.61, respectively. Excluding the effect of PSC-type contracts, production costs on a per barrel basis[1] for 2019 and 2018 would have been $17.32 and $17.44, respectively.

G&A expenses were $62 million for the fourth quarter of 2019, compared to $65 million for the same prior-year period. The decrease was primarily attributable to the workforce reduction that was implemented in the fourth quarter of 2019 and consolidating our office space, partially offset by equity compensation expense resulting from movements in our stock price.

CRC reported taxes other than on income of $38 million for the fourth quarter of 2019, compared to $29 million for the same prior-year period. Exploration expense was $4 million for the fourth quarter of 2019, $12 million lower than the $16 million reported in same prior-year period due to lower activity.

Total capital invested during the fourth quarter of 2019 was $146 million, within our guidance. CRC internally funded $62 million, of which $45 million was directed to drilling and capital workovers. CRC's JV partners Macquarie Infrastructure and Real Assets Inc. (MIRA) and Alpine invested an additional $13 million and $71 million, respectively, which are excluded from CRC's consolidated results.

Cash provided by operating activities for the fourth quarter of 2019 was $136 million and free cash flow[1] was $74 million after taking into account CRC's internally funded capital.

**Full Year 2019 Results**

For the full year of 2019, CRC net loss was $28 million, or $0.57 per diluted share, compared to a net income attributable to common stock of $328 million, or $6.77 per diluted share, for 2018. Including hedge settlements, the 2019 results reflected higher year-over-year oil and natural gas sales despite a lower oil price environment. Adjusted net income[1] for 2019 was $70 million, or $1.40 per diluted share, compared with an adjusted net income[1] of $61 million, or $1.27 per diluted share, for 2018. The 2019 adjusted net income[1] excluded $166 million of non-cash derivative losses, a net gain of $126 million from debt repurchases, $47 million in severance and termination benefits and a net $11 million charge related to other unusual and infrequent items. Adjusted net income[1] for 2018 excluded $224 million on non-cash derivative gains, a net gain of $57 million from debt repurchases, $4 million in severance and termination benefits and a net $10 million charge related to other unusual and infrequent items.

Total daily net production volumes averaged 128,000 BOE per day for full year 2019, compared with 132,000 BOE per day for 2018, a decrease of 3 percent. The 2018 volumes reflect three quarters of production from the April 2018 Elk Hills acquisition. The 2019 volumes reflect the effect of the strategic Lost Hills divestiture that occurred in May 2019.

In 2019, realized crude oil prices, including the effect of settled hedges, increased $6.05 per barrel to $68.65 per barrel from $62.60 per barrel in 2018. Settled hedges increased 2019 realized crude oil prices by $3.82 per barrel, compared with a reduction of $7.51 per barrel for the same period in 2018. Realized NGL prices decreased 27 percent, or $11.96 per barrel to $31.71 per barrel in 2019 from $43.67 per barrel in 2018. Realized natural gas prices decreased $0.13 per Mcf to $2.87 per Mcf, compared with $3.00 per Mcf in 2018, largely due to increased national supply and milder weather in 2019.

Production costs for full year 2019 were $895 million, or $19.16 per BOE, compared to $912 million, or $18.88 per BOE, in 2018. The decrease in total production costs was primarily attributable to the Lost Hills divestiture along with the effect of the workforce reduction and lower downhole maintenance activity, while per unit costs increased with the decline in total production. Per unit production costs, excluding the effect of PSCs[1], were $17.70 and $17.47 per BOE for 2019 and 2018, respectively.

G&A expenses for the full year of 2019 were $290 million, compared to $299 million in the same prior-year period, with the decrease largely due to lower equity compensation expense in 2019 as a result of a lower stock price and a reduction in headcount in the fourth quarter of 2019.

Taxes other than on income were $157 million for 2019 compared to $149 million in 2018. Exploration expense of $29 million for 2019 was 15 percent lower than the $34 million in 2018.

CRC's internally funded capital investment in 2019 totaled $407 million, of which $302 million was directed to drilling and capital workovers. CRC's JV partners invested $205 million in 2019, all of which was directed to drilling. Of our JV partners' investment, BSP invested $48 million which is included in CRC's consolidated results.

Cash provided by operating activities for the full year of 2019 was $676 million and free cash flow[1] was $269 million after taking into account CRC's internally funded capital.

## Operational Update

In the fourth quarter of 2019, CRC operated an average of eight drilling rigs, with two on primary, one on waterfloods, one on steamfloods and four on unconventional production. With total invested capital, we drilled 104 development wells (41 primary, 14 waterflood, 32 steamflood, and 17 unconventional). 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 period that the well is drilled. The San Joaquin basin produced 91,000 net BOE per day and operated seven rigs. The Los Angeles basin contributed 23,000 net

BOE per day of production and operated one rig directed toward waterflood projects. The Ventura basin produced 4,000 net BOE per day and the Sacramento basin produced 5,000 net BOE per day, both with no active drilling program.

**2020 Capital Budget**

CRC expects its 2020 internally funded capital program will range from $100 million to $300 million. CRC anticipates JV investment of $160 to $200 million for 2020. CRC anticipates a total capital program of approximately $260 to $500 million for the year. At current prices, CRC's capital plan will target the lower end of the guidance range. CRC's 2020 capital is focused on oil and largely directed to short payout projects like capital workovers, especially in the first half of the year, as well as primary drilling of both vertical and lateral wells and low-risk projects including waterflood and steamflood investments that maintain base production.

**Repurchases and Balance Sheet Update**

During the fourth quarter of 2019, CRC repurchased $23 million in face value of Second Lien Notes for $7 million. The aggregate face value repurchased since the Second Liens were issued is $442 million to-date, including $183 million in 2018, $252 million in 2019 and $7 million in 2020. Net debt outstanding at the end of the fourth quarter was under $5.0 billion.

The borrowing base under the Company's 2014 Revolving Credit Facility was reconfirmed effective November 1, 2019 at $2.3 billion.

On February 20, 2020, CRC launched an offer to exchange a significant portion of its Second Lien Notes and senior notes into notes and equity interests in a new entity that holds a royalty interest in the Elk Hills unit, and a new first lien last out term loan and warrants convertible into CRC's common stock. The Elk Hills unit comprises approximately 98% by acreage and 98% by production of our Elk Hills field. If fully subscribed, the transaction would have the effect of reducing CRC's net debt by almost $1 billion. The transaction is expected to close March 20, 2020.

**Hedging Update**

CRC continues to execute an opportunistic hedging program to protect its cash flow, operating margins and capital program, while maintaining adequate liquidity. For the first and second quarters of 2020, CRC has protected the downside risk of 30,000 and 20,000 barrels of oil per day at approximately $71 Brent and $68 Brent, respectively. These put spreads provide downside price protection when Brent prices drop below $57 and $54 per barrel in the first and second quarters, respectively, at which point CRC receives Brent plus approximately $14 per barrel. CRC also entered into a swap for 5,000 barrels of oil per day in the second quarter of 2020 at approximately $70 Brent, which may be increased by another 5,000 barrels per day at the same price at the option of the counterparties. For the third and fourth quarters of 2020, CRC has protected the downside risk of 13,000 and 8,000 barrels of oil per day, respectively, at $65 per barrel. These put spreads provide downside protection when Brent prices drop below approximately $54 and $53 per barrel in the respective quarters, at which point CRC receives Brent plus approximately $11 and $12 per barrel in the respective quarters. CRC also entered into a swap at a price of $65 Brent and sold a put at a price of $55 per barrel on 5,000 barrels of oil per day for the third and fourth quarters of 2020. For these hedges, CRC will receive $65 per barrel at all prices except when Brent drops below $55 per barrel, where CRC will receive Brent plus $10 per barrel. These swaps may be increased by another 5,000 barrels per day at the same price at the option of the counterparty. See Attachment 9 for more details.

## Sustainability Performance

In 2019, CRC met or surpassed its health, safety and environmental metrics published in its 2019 Proxy. CRC's workforce achieved the best-ever injury and illness incidence rate in its operations in 2019 with zero employee recordable events and an overall rate including contractors of 0.34 recordable events per 200,000 hours worked, which is better than office-based occupations such as radio broadcasters, insurance agents and stockbrokers according to the most recent U.S. Bureau of Labor Statistics data. CRC also surpassed its environmental stewardship targets for spill prevention and water conservation, and delivered more than three gallons of reclaimed water to agriculture for every gallon of fresh water CRC purchased in 2019.

In addition to attaining CDP's Leadership Level for climate disclosure, CRC made continued progress in 2019 toward its quantitative 2030 Sustainability Goals for water recycling, renewables integration, methane emission reduction and carbon capture and sequestration that align directly with the State's long-term goals. For 2020, CRC has adopted additional annual sustainability metrics for incentive compensation that incorporate specific milestones for sustainability projects, workforce diversity and development, and community partnerships that will be summarized in CRC's 2020 Proxy.

[1] See Attachment 3 for non-GAAP financial measures of adjusted EBITDAX, adjusted EBITDAX margin, production costs (excluding effects of PSC-type contracts), adjusted net income (loss) and free cash flow after internally funded capital, including reconciliations to their most directly comparable GAAP measure, where applicable.

## Conference Call Details

To participate in the conference call scheduled for February 26th, 2020 at 5:00 P.M. Eastern Standard 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/10137361. 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. CRC 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 CRC's expectations as to its future:

- financial position, liquidity, cash flows and results of operations
- business prospects
- transactions and projects
- operating costs
- Value Creation Index (VCI) metrics, which are based on certain estimates including future production rates, costs and commodity prices
- operations and operational results including production, hedging and capital investment
- budgets and maintenance capital requirements
- reserves
- type curves
- expected synergies from acquisitions and joint ventures

Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. While CRC believes assumptions or bases underlying its expectations are reasonable and makes them in good faith, they almost always vary from actual results, sometimes materially. CRC also believes third-party statements it cites are accurate, but has not independently verified them and does 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 CRC's financial flexibility
- insufficient cash flow to fund planned investments, debt repurchases or changes to our capital plan
- inability to enter into desirable transactions, including acquisitions, asset sales and joint ventures
- legislative or regulatory changes, including those related to drilling, completion, well stimulation, operation, inspection, 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 CRC's products
- joint ventures and acquisitions and CRC's ability to achieve expected synergies
- the recoverability of resources and unexpected geologic conditions
- incorrect estimates of reserves and related future cash flows and the inability to replace reserves
- changes in business strategy
- PSC effects on production and unit production costs
- effect of stock price on costs associated with incentive compensation
- insufficient capital or liquidity, including as a result of lender restrictions, the unavailability of capital markets or inability to attract potential investors
- effects of hedging transactions
- 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, joint ventures or acquisitions, or higher-than-expected decline rates
- disruptions due to accidents, mechanical failures, power outages, transportation or storage constraints, natural disasters, pandemics, labor difficulties, cyber attacks or other catastrophic events
- factors discussed in “Item 1A - Risk Factors” in CRC's Annual Report on Form 10-K available on its 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 CRC 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:**


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**SUMMARY OF RESULTS**

| ($ and shares in millions, except per share amounts) | Fourth Quarter **2019** | Fourth Quarter 2018 | Twelve Months **2019** | Twelve Months 2018 |
|---|---|---|---|---|
| **Statements of Operations:** | | | | |
| **Revenues** | | | | |
| Oil and natural gas sales | **$ 550** | $ 658 | **$ 2,270** | $ 2,590 |
| Net derivative (loss) gain from commodity contracts | **(28)** | 260 | **(59)** | 1 |
| Other revenue | | | | |
| Trading | **56** | 125 | **286** | 330 |
| Electricity sales | **24** | 24 | **112** | 111 |
| Other | **8** | 11 | **25** | 32 |
| Total revenues | **610** | 1,078 | **2,634** | 3,064 |
| **Costs and Other** | | | | |
| Production costs | **211** | 233 | **895** | 912 |
| General and administrative expenses | **62** | 65 | **290** | 299 |
| Depreciation, depletion and amortization | **114** | 130 | **471** | 502 |
| Taxes other than on income | **38** | 29 | **157** | 149 |
| Exploration expense | **4** | 16 | **29** | 34 |
| Other expenses, net | | | | |
| Trading purchases | **31** | 94 | **201** | 250 |
| Elk Hills Power costs | **17** | 18 | **68** | 61 |
| Transportation costs | **10** | 11 | **40** | 36 |
| Other | **21** | 17 | **54** | 52 |
| Total costs and other | **508** | 613 | **2,205** | 2,295 |
| **Operating Income** | **102** | 465 | **429** | 769 |
| **Non-Operating (Loss) Income** | | | | |
| Interest and debt expense, net | **(90)** | (98) | **(383)** | (379) |
| Net gain on early extinguishment of debt | **18** | 31 | **126** | 57 |
| Gain on asset divestitures | **—** | 1 | **—** | 5 |
| Other non-operating expenses | **(54)** | (7) | **(72)** | (23) |
| **(Loss) Income Before Income Taxes** | **(24)** | 392 | **100** | 429 |
| Income tax provision | **(1)** | — | **(1)** | |
| **Net (Loss) Income** | **(25)** | 392 | **99** | 429 |
| Net income attributable to noncontrolling interests | **(42)** | (46) | **(127)** | (101) |
| **Net (Loss) Income Attributable to Common Stock** | **$ (67)** | $ 346 | **$ (28)** | $ 328 |
| Net (loss) income attributable to common stock per share - basic | **$ (1.36)** | $ 7.00 | **$ (0.57)** | $ 6.77 |
| Net (loss) income attributable to common stock per share - diluted | **$ (1.36)** | $ 7.00 | **$ (0.57)** | $ 6.77 |
| Adjusted net income | **$ 36** | $ 26 | **$ 70** | $ 61 |
| Adjusted net income per share - basic | **$ 0.73** | $ 0.53 | **$ 1.41** | $ 1.27 |
| Adjusted net income per share - diluted | **$ 0.73** | $ 0.53 | **$ 1.40** | $ 1.27 |
| Weighted-average common shares outstanding - basic | **49.1** | 48.6 | **49.0** | 47.4 |
| Weighted-average common shares outstanding - diluted | **49.2** | 49.1 | **49.2** | 47.4 |
| Adjusted EBITDAX | **$ 308** | $ 314 | **$ 1,142** | $ 1,117 |
| Effective tax rate | **4%** | 0% | **1%** | 0% |

| ($ in millions) | Fourth Quarter 2019 | Fourth Quarter 2018 | Twelve Months 2019 | Twelve Months 2018 |
|---|---|---|---|---|
| **Cash Flow Data:** | | | | |
| Net cash provided by operating activities | **$ 136** | $ 68 | **$ 676** | $ 461 |
| Net cash used in investing activities | **$ (103)** | $ (191) | **$ (394)** | $ (1,156) |
| Net cash (used) provided by financing activities | **$ (38)** | $ 109 | **$ (282)** | $ 692 |

| ($ and shares in millions) | **December 31, 2019** | December 31, 2018 |
|---|---|---|
| **Selected Balance Sheet Data:** | | |
| Total current assets | **$ 491** | $ 640 |
| Property, plant and equipment, net | **$ 6,352** | $ 6,455 |
| Total current liabilities | **$ 709** | $ 607 |
| Long-term debt | **$ 4,877** | $ 5,251 |
| Deferred gain and issuance costs, net | **$ 146** | $ 216 |
| Other long-term liabilities | **$ 720** | $ 575 |
| Mezzanine equity | **$ 802** | $ 756 |
| Equity | **$ (296)** | $ (247) |
| Outstanding shares | **49.2** | 48.7 |

## STOCK-BASED COMPENSATION

Our consolidated results of operations for the three months and year ended December 31, 2019 and 2018 include the effects of long-term stock-based compensation plans under which awards are granted annually to executives, non-executive employees and non-employee directors that are either settled with shares of our common stock or cash. Our equity-settled awards granted to executives include stock options, restricted stock units and performance stock units that either cliff vest at the end of a three-year period or vest ratably over a three year period, some of which are partially settled in cash. Our equity-settled awards granted to non-employee directors are restricted stock grants that either vest immediately or restricted stock units that cliff vest after one year. Our cash-settled awards granted to non-executive employees vest ratably over a three-year period.

Changes in our stock price introduce volatility in our results of operations because we pay cash-settled awards based on our stock price on the vesting date and accounting rules require that we adjust our obligation for unvested awards to the amount that would be paid using our stock price at the end of each reporting period. Cash-settled awards, including executive awards partially settled in cash, account for almost 70% of our total outstanding awards. Equity-settled awards are not similarly adjusted for changes in our stock price.

Stock-based compensation is included in both general and administrative expenses and production costs as shown in the table below:

| | Fourth Quarter | | Twelve Months | |
|---|---|---|---|---|
| ($ in millions, except per BOE amounts) | **2019** | 2018 | **2019** | 2018 |
| **General and administrative expenses (G&A)** | | | | |
| Cash-settled awards | **$ 3** | $ (10) | **$ 14** | $ 23 |
| Equity-settled awards | **1** | 2 | **11** | 13 |
| Total in G&A | **$ 4** | $ (8) | **$ 25** | $ 36 |
| Total in G&A per Boe | **$ 0.35** | $ (0.64) | **$ 0.54** | $ 0.75 |
| **Production costs** | | | | |
| Cash-settled awards | **$ —** | $ (2) | **$ 4** | $ 6 |
| Equity-settled awards | **—** | — | **3** | 3 |
| Total in production costs | **$ —** | $ (2) | **$ 7** | $ 9 |
| Total in production costs per Boe | **$ —** | $ (0.16) | **$ 0.15** | $ 0.19 |
| Total company | **$ 4** | $ (10) | **$ 32** | $ 45 |
| Total company per Boe | **$ 0.35** | $ (0.80) | **$ 0.69** | $ 0.94 |

## DERIVATIVE GAINS AND LOSSES

The following table presents the components of our net derivative losses and gains from commodity contracts and our non-cash derivative loss from interest-rate contracts. Our non-cash derivative loss from interest-rate contracts is reported in other non-operating expenses.

| | Fourth Quarter | | Twelve Months | |
|---|---|---|---|---|
| ($ millions) | **2019** | 2018 | **2019** | 2018 |
| **Commodity Contracts:** | | | | |
| Non-cash derivative (loss) gain excluding noncontrolling interest | **$ (67)** | $ 295 | **$ (166)** | $ 224 |
| Non-cash derivative (loss) gain - noncontrolling interest | **(4)** | 15 | **(4)** | 5 |
| Total non-cash changes | **(71)** | 310 | **(170)** | 229 |
| Net proceeds (payments) on settled commodity derivatives | **43** | (50) | **111** | (228) |
| Net derivative (loss) gain from commodity contracts | **$ (28)** | $ 260 | **$ (59)** | $ 1 |
| **Interest-Rate Contracts:** | | | | |
| Non-cash derivative loss | **$ —** | $ (6) | **$ (4)** | $ (6) |

**PRODUCTION STATISTICS**

| Net Oil, NGLs and Natural Gas Production Per Day | Fourth Quarter 2019 | Fourth Quarter 2018 | Twelve Months 2019 | Twelve Months 2018 |
|---|---|---|---|---|
| **Oil (MBbl/d)** | | | | |
| San Joaquin Basin | **50** | 56 | **52** | 53 |
| Los Angeles Basin | **23** | 26 | **24** | 25 |
| Ventura Basin | **3** | 4 | **4** | 4 |
| Total | **76** | 86 | **80** | 82 |
| **NGLs (MBbl/d)** | | | | |
| San Joaquin Basin | **15** | 15 | **15** | 15 |
| Ventura Basin | **—** | 1 | **—** | 1 |
| Total | **15** | 16 | **15** | 16 |
| **Natural Gas (MMcf/d)** | | | | |
| San Joaquin Basin | **157** | 168 | **162** | 165 |
| Los Angeles Basin | **2** | 2 | **2** | 1 |
| Ventura Basin | **5** | 7 | **5** | 7 |
| Sacramento Basin | **26** | 27 | **28** | 29 |
| Total | **190** | 204 | **197** | 202 |
| **Total Production (MBoe/d)** | **123** | 136 | **128** | 132 |

| Gross Oil, NGLs and Natural Gas Production Per Day | Fourth Quarter 2019 | Fourth Quarter 2018 | Twelve Months 2019 | Twelve Months 2018 |
|---|---|---|---|---|
| **Oil (MBbl/d)** | | | | |
| San Joaquin Basin | **54** | 59 | **56** | 59 |
| Los Angeles Basin | **31** | 34 | **32** | 34 |
| Ventura Basin | **4** | 5 | **5** | 5 |
| Total | **89** | 98 | **93** | 98 |
| **NGLs (MBbl/d)** | | | | |
| San Joaquin Basin | **15** | 16 | **15** | 16 |
| Ventura Basin | **—** | 1 | **—** | 1 |
| Total | **15** | 17 | **15** | 17 |
| **Natural Gas (MMcf/d)** | | | | |
| San Joaquin Basin | **161** | 168 | **164** | 170 |
| Los Angeles Basin | **10** | 9 | **9** | 8 |
| Ventura Basin | **5** | 7 | **5** | 7 |
| Sacramento Basin | **35** | 36 | **38** | 38 |
| Total | **211** | 220 | **216** | 223 |
| **Total Production (MBoe/d)** | **140** | 152 | **144** | 152 |

Note: MBbl/d refers to thousands of barrels per day; MMcf/d refers to millions of cubic feet per day; MBoe/d refers to thousands of barrels of oil equivalent (Boe) per day. Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of natural gas to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

**NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS**

Our results of operations, which are presented in accordance with U.S. generally accepted accounting principles (GAAP), 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 derivative gains and losses) in nature, timing, amount and frequency. Therefore, management uses certain non-GAAP measures to assess our financial condition, results of operations and cash flows. These measures are widely used by the industry, the investment community and our lenders. Although these are non-GAAP measures, the amounts included in the calculations were computed in accordance with GAAP. Certain items excluded from these non-GAAP measures 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. These measures should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP.

Below are additional disclosures regarding each of the non-GAAP measures reported in this press release, including reconciliations to their most directly comparable GAAP measure where applicable.

**ADJUSTED NET INCOME (LOSS)**

Management uses a measure called adjusted net income (loss) to provide useful information to investors interested in comparing our core operations between periods and our performance to our peers. This measure is not meant to disassociate the effects of unusual, out-of-period and infrequent items affecting earnings from management's performance but rather is meant to provide useful information to investors interested in comparing our financial 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 GAAP. 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 and presents the GAAP financial measure of net income (loss) attributable to common stock per diluted share and the non-GAAP financial measure of adjusted net income per diluted share.

| | Fourth Quarter | | Twelve Months | |
|---|---|---|---|---|
| ($ millions, except per share amounts) | **2019** | 2018 | **2019** | 2018 |
| Net (loss) income | **$ (25)** | $ 392 | **$ 99** | $ 429 |
| Net income attributable to noncontrolling interests | **(42)** | (46) | **(127)** | (101) |
| Net (loss) income attributable to common stock | **(67)** | 346 | **(28)** | 328 |
| Unusual, infrequent and other items: | | | | |
| Non-cash derivative (gain) loss from commodities, excluding noncontrolling interest | **67** | (295) | **166** | (224) |
| Non-cash derivative loss from interest-rate contracts | **—** | 6 | **4** | 6 |
| Severance and termination benefits | **45** | — | **47** | 4 |
| Gain on asset divestitures | **—** | (1) | **—** | (5) |
| Net gain on early extinguishment of debt | **(18)** | (31) | **(126)** | (57) |
| Other, net | **9** | 1 | **7** | 9 |
| Total unusual, infrequent and other items | **103** | (320) | **98** | (267) |
| Adjusted net income | **$ 36** | $ 26 | **$ 70** | $ 61 |
| Net (loss) income attributable to common stock per share - diluted | **$ (1.36)** | $ 7.00 | **$ (0.57)** | $ 6.77 |
| Adjusted net income per share - diluted | **$ 0.73** | $ 0.53 | **$ 1.40** | $ 1.27 |

**FREE CASH FLOW**

Management uses free cash flow, which is defined by us as net cash provided by operating activities less capital investments, as a measure of liquidity. The following table presents a reconciliation of our net cash provided by operating activities to free cash flow.

| | Fourth Quarter | | Twelve Months | |
|---|---|---|---|---|
| ($ millions) | **2019** | 2018 | **2019** | 2018 |
| Net cash provided by operating activities | **$ 136** | $ 68 | **$ 676** | $ 461 |
| Capital investments | **(62)** | (186) | **(455)** | (690) |
| Free cash flow | **74** | (118) | **221** | (229) |
| BSP funded capital | **—** | 12 | **48** | 49 |
| Free cash flow, after internally funded capital | **$ 74** | $ (106) | **$ 269** | $ (180) |

## ADJUSTED EBITDAX

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. Management uses adjusted EBITDAX as a measure of operating cash flow without working capital adjustments. A version of adjusted EBITDAX 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. The following table presents a reconciliation of the GAAP financial measures of net income (loss) and net cash provided by operating activities to the non-GAAP financial measure of adjusted EBITDAX.

| | Fourth Quarter | | Twelve Months | |
|---|---|---|---|---|
| ($ millions, except per BOE amounts) | **2019** | 2018 | **2019** | 2018 |
| Net (loss) income | **$ (25)** | $ 392 | **$ 99** | $ 429 |
| Interest and debt expense, net | **90** | 98 | **383** | 379 |
| Depreciation, depletion and amortization | **114** | 130 | **471** | 502 |
| Exploration expense | **4** | 16 | **29** | 34 |
| Unusual, infrequent and other items [(a)] | **103** | (320) | **98** | (267) |
| Other non-cash items | **22** | (2) | **62** | 40 |
| **Adjusted EBITDAX** | **$ 308** | $ 314 | **$ 1,142** | $ 1,117 |
| | | | | |
| Net cash provided by operating activities | **$ 136** | $ 68 | **$ 676** | $ 461 |
| Cash interest | **139** | 157 | **439** | 441 |
| Exploration expenditures | **3** | 3 | **18** | 17 |
| Working capital changes | **29** | 86 | **8** | 199 |
| Other, net | **1** | — | **1** | (1) |
| **Adjusted EBITDAX** | **$ 308** | $ 314 | **$ 1,142** | $ 1,117 |
| | | | | |
| **Adjusted EBITDAX per Boe** | **$ 27.25** | $ 25.08 | **$ 24.45** | $ 23.13 |

(a) See Adjusted Net Income reconciliation.

## DISCRETIONARY CASH FLOW

We define discretionary cash flow as the cash available after distributions to noncontrolling interest holders and cash interest, excluding the effect of working capital changes but before our internal capital investment. Management uses discretionary cash flow as a measure of the availability of cash to reduce debt or fund investments.

| | Fourth Quarter | | Twelve Months | |
|---|---|---|---|---|
| ($ millions) | **2019** | 2018 | **2019** | 2018 |
| Adjusted EBITDAX | **$ 308** | $ 314 | **$ 1,142** | $ 1,117 |
| Cash interest | **(139)** | (157) | **(439)** | (441) |
| Distributions paid to noncontrolling interest holders: | | | | |
| BSP | **(16)** | (21) | **(71)** | (56) |
| Ares | **(20)** | (20) | **(80)** | (65) |
| Discretionary cash flow | **$ 133** | $ 116 | **$ 552** | $ 555 |

## ADJUSTED EBITDAX MARGIN

Management uses adjusted EBITDAX margin as a measure of profitability between periods and this measure is generally used by analysts for comparative purposes within the industry.

| | Fourth Quarter | | Twelve Months | |
|---|---|---|---|---|
| ($ millions) | **2019** | 2018 | **2019** | 2018 |
| Total revenues | **$ 610** | $ 1,078 | **$ 2,634** | $ 3,064 |
| Non-cash derivative loss (gain) | **71** | (310) | **170** | (229) |
| Revenues, excluding non-cash derivative gains and losses | **$ 681** | $ 768 | **$ 2,804** | $ 2,835 |
| Adjusted EBITDAX margin | **45%** | 41% | **41%** | 39% |

## ADJUSTED GENERAL AND ADMINISTRATIVE EXPENSES

Management uses a measure called adjusted general and administrative expenses to provide useful information to investors interested in comparing our costs between periods and our performance to our peers. The following table presents a reconciliation of the GAAP financial measure of general and administrative expenses to the non-GAAP financial measure of adjusted general and administrative expenses.

| | Fourth Quarter | | Twelve Months | |
|---|---|---|---|---|
| | **2019** | 2018 | **2019** | 2018 |
| General and administrative expenses | **$ 62** | $ 65 | **$ 290** | $ 299 |
| Severance costs | **(1)** | — | **(3)** | (1) |
| Adjusted general and administrative expenses | **$ 61** | $ 65 | **$ 287** | $ 298 |

## PRODUCTION COSTS PER BOE

The reporting of our PSC-type contracts creates a difference between reported production costs, which are for the full field, and reported volumes, which are only our net share, inflating the per barrel production costs. The following table presents production costs after adjusting for the excess costs attributable to PSC-type contracts.

| | Fourth Quarter | | Twelve Months | |
|---|---|---|---|---|
| ($ per Boe) | **2019** | 2018 | **2019** | 2018 |
| Production costs | **$ 18.67** | $ 18.61 | **$ 19.16** | $ 18.88 |
| Excess costs attributable to PSC-type contracts | **(1.35)** | (1.17) | **(1.46)** | (1.41) |
| Production costs, excluding effects of PSC-type contracts | **$ 17.32** | $ 17.44 | **$ 17.70** | $ 17.47 |

## PV-10 AND STANDARDIZED MEASURE

The following table presents a reconciliation of the GAAP financial measure of Standardized Measure of discounted future net cash flows (Standardized Measure) to the non-GAAP financial measure of PV-10:

| **($ millions)** | **2019** |
|---|---|
| Standardized Measure of discounted future net cash flows | $ 5,231 |
| Present value of future income taxes discounted at 10% | 1,618 |
| PV-10 of proved reserves (1) | $ 6,849 |

(1) PV-10 is a non-GAAP financial measure and represents the year-end present value of estimated future cash inflows from proved oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows and using SEC prescribed pricing assumptions for the period. PV-10 differs from Standardized Measure because Standardized Measure includes the effects of future income taxes on future net cash flows. Neither PV-10 nor Standardized Measure should be construed as the fair value of our oil and natural gas reserves. Standardized Measure is prescribed by the SEC as an industry standard asset value measure to compare reserves with consistent pricing, costs and discount assumptions. PV-10 facilitates the comparisons to other companies as it is not dependent on the tax-paying status of the entity.

| **Reserve Replacement Ratio** [1] | | **2019** |
|---|---|---|
| Organic Reserve Replacement Ratio [2] | | |
| Extensions and discoveries | $ | 33 |
| Improved recovery | | 3 |
| Revisions related to performance | | 16 |
| Organic proved reserves added - MMBOE (A) | $ | 52 |
| | | |
| Production in 2019 - MMBOE (B) | | 47 |
| Organic reserve replacement ratio (A)/(B) | | 111 % |

(1) The reserve replacement ratio is a measurement that management uses to gauge the results of its capital program. There is no guarantee that historical sources of reserves additions will continue as many factors fully or partially outside management's control, including commodity prices, availability of capital and the underlying geology, affect reserves additions. Management uses this measure to gauge the results of its capital program. Other oil and gas producers may use different methods to calculate replacement ratios, which may affect comparability.

(2) The organic reserve replacement ratio is calculated for a specified period using the proved oil-equivalent additions from extensions and discoveries, improved recovery and net performance-related revisions divided by oil-equivalent production.

| **Finding and Development Costs** [3] | | **2019** |
|---|---|---|
| Organic costs incurred - in millions (A) | $ | 535 |
| Less: asset retirement costs due to idle well regulations - in millions | | (80) |
| Organic finding and development costs - in millions (B) [4] | $ | 455 |
| | | |
| Organic proved reserves added - MMBOE (C) | | 52 |
| Organic finding and development costs - $/BOE (A)/(C) [4] | $ | 8.75 |

(3) We believe that reporting our finding and development costs can aid investors in their evaluation of our ability to add proved reserves at a reasonable cost but is not a substitute for required GAAP disclosures. Various factors, primarily timing differences and effects of commodity price changes, can cause finding and development costs associated with a particular period's reserves additions to be imprecise. For example, we will need to make more investments in order to develop the proved undeveloped reserves added during the year and any future revisions may change the actual measure from that presented above. In addition, part of the 2019 costs were incurred to convert proved undeveloped reserves from prior years to proved developed reserves. In our calculations, we have not estimated future costs to develop proved undeveloped reserves added in 2019 or removed costs related to proved undeveloped reserves added in prior periods. Our calculations of finding and development costs may not be comparable to similar measures provided by other companies.

(4) We calculate organic finding and development costs by dividing the costs incurred for the year from the capital program, excluding the increase in asset retirement costs substantially due to new idle well regulations issued in the first quarter, by the amount of oil-equivalent proved reserves added in the same year from improved recovery, extensions and discoveries and net performance-related revisions.

**CAPITAL INVESTMENTS**

| ($ millions) | Fourth Quarter 2019 | Fourth Quarter 2018 | Twelve Months 2019 | Twelve Months 2018 |
|---|---|---|---|---|
| Internally funded capital | **$ 62** | $ 174 | **$ 407** | $ 641 |
| BSP funded capital | **—** | 12 | **48** | 49 |
| Capital investments - as reported | **$ 62** | $ 186 | **$ 455** | $ 690 |
| MIRA funded capital | **13** | 11 | **23** | 57 |
| Alpine funded capital | **71** | — | **134** | — |
| Total capital program | **$ 146** | $ 197 | **$ 612** | $ 747 |

**PRICE STATISTICS**

| | Fourth Quarter | | Twelve Months | |
|---|---|---|---|---|
| | **2019** | 2018 | **2019** | 2018 |
| **Realized Prices** | | | | |
| Oil with hedge ($/Bbl) | **$ 70.21** | $ 59.97 | **$ 68.65** | $ 62.60 |
| Oil without hedge ($/Bbl) | **$ 64.22** | $ 66.12 | **$ 64.83** | $ 70.11 |
| NGLs ($/Bbl) | **$ 33.81** | $ 43.56 | **$ 31.71** | $ 43.67 |
| Natural gas ($/Mcf) | **$ 3.00** | $ 3.77 | **$ 2.87** | $ 3.00 |
| **Index Prices** | | | | |
| Brent oil ($/Bbl) | **$ 62.50** | $ 68.08 | **$ 64.18** | $ 71.53 |
| WTI oil ($/Bbl) | **$ 56.96** | $ 58.81 | **$ 57.03** | $ 64.77 |
| NYMEX gas ($/MMBtu) | **$ 2.50** | $ 3.40 | **$ 2.67** | $ 2.97 |
| **Realized Prices as Percentage of Index Prices** | | | | |
| Oil with hedge as a percentage of Brent | **112%** | 88% | **107%** | 88% |
| Oil without hedge as a percentage of Brent | **103%** | 97% | **101%** | 98% |
| Oil with hedge as a percentage of WTI | **123%** | 102% | **120%** | 97% |
| Oil without hedge as a percentage of WTI | **113%** | 112% | **114%** | 108% |
| NGLs as a percentage of Brent | **54%** | 64% | **49%** | 61% |
| NGLs as a percentage of WTI | **59%** | 74% | **56%** | 67% |
| Natural gas as a percentage of NYMEX | **120%** | 111% | **107%** | 101% |

**FOURTH QUARTER DRILLING ACTIVITY**

| Wells Drilled | San Joaquin Basin | Los Angeles Basin | Ventura Basin | Sacramento Basin | Total |
|---|---|---|---|---|---|
| **Development Wells** | | | | | |
| Primary | 41 | — | — | — | 41 |
| Waterflood | 5 | 9 | — | — | 14 |
| Steamflood | 32 | — | — | — | 32 |
| Unconventional | 17 | — | — | — | 17 |
| Total | 95 | 9 | — | — | 104 |
| **Exploration Wells** | | | | | |
| Primary | — | — | — | — | — |
| Waterflood | — | — | — | — | — |
| Steamflood | — | — | — | — | — |
| Unconventional | — | — | — | — | — |
| Total | — | — | — | — | — |
| **Total [a]** | 95 | 9 | — | — | 104 |

| Wells Drilled | San Joaquin Basin | Los Angeles Basin | Ventura Basin | Sacramento Basin | Total |
|---|---|---|---|---|---|
| CRC | 7 | 8 | — | — | 15 |
| BSP | — | 1 | — | — | 1 |
| MIRA | 32 | — | — | — | 32 |
| Alpine | 56 | — | — | — | 56 |
| **Total [a]** | 95 | 9 | — | — | 104 |

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

FULL YEAR 2019 DRILLING ACTIVITY

| Wells Drilled | San Joaquin Basin | Los Angeles Basin | Ventura Basin | Sacramento Basin | Total |
|---|---|---|---|---|---|
| **Development Wells** | | | | | |
| Primary | 104 | — | — | — | 104 |
| Waterflood | 39 | 31 | — | — | 70 |
| Steamflood | 62 | — | — | — | 62 |
| Unconventional | 49 | — | — | — | 49 |
| Total | 254 | 31 | — | — | 285 |
| **Exploration Wells** | | | | | |
| Primary | 2 | — | 2 | — | 4 |
| Waterflood | — | — | — | — | — |
| Steamflood | 5 | — | — | — | 5 |
| Unconventional | — | — | — | — | — |
| Total | 7 | — | 2 | — | 9 |
| **Total** [(a)] | 261 | 31 | 2 | — | 294 |

| Wells Drilled | San Joaquin Basin | Los Angeles Basin | Ventura Basin | Sacramento Basin | Total |
|---|---|---|---|---|---|
| CRC | 105 | 19 | 2 | — | 126 |
| BSP | 15 | 12 | — | — | 27 |
| MIRA | 33 | — | — | — | 33 |
| Alpine | 108 | — | — | — | 108 |
| **Total** [(a)] | 261 | 31 | 2 | — | 294 |

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

**HEDGES - CURRENT**

| | Q1 2020 | Q2 2020 | Q3 2020 | Q4 2020 |
|---|---|---|---|---|
| **CRUDE OIL** | | | | |
| Purchased Puts: | | | | |
| Barrels per day | 30,000 | 20,000 | 13,000 | 8,000 |
| Weighted-average Brent price per barrel | $70.83 | $67.50 | $65.00 | $65.00 |
| Sold Puts: | | | | |
| Barrels per day | 30,000 | 20,000 | 18,000 | 13,000 |
| Weighted-average Brent price per barrel | $56.67 | $53.75 | $54.31 | $53.81 |
| Swaps: | | | | |
| Barrels per day | — | 5,000 [a] | 5,000 [a] | 5,000 [a] |
| Weighted-average Brent price per barrel | $— | $70.05 | $65.00 | $65.00 |

(a) Our counterparties have an option to increase volumes by up to 5,000 barrels per day for the second quarter of 2020 at a weighted-average Brent price of $70.05. A counterparty has an option to increase volumes by up to 5,000 barrels per day for the second half of 2020 at a weighted-average Brent price of $65.00.

The BSP JV entered into crude oil derivatives for insignificant volumes through 2021 that are included in our consolidated results but not in the above table. The BSP JV also entered into natural gas swaps for insignificant volumes for periods through May 2021. The hedges entered into by the BSP JV could affect the timing of the redemption of BSP's noncontrolling interest.

In May 2018 we entered into derivative contracts that limit our interest rate exposure with respect to $1.3 billion of our variable-rate indebtedness. The interest rate contracts reset monthly and require the counterparties to pay any excess interest owed on such amount in the event the one-month LIBOR exceeds 2.75% for any monthly period prior to May 2021.

**2020 FIRST QUARTER GUIDANCE**

| | |
|---|---|
| **Anticipated Realizations Against the Prevailing Index Prices for Q1 2020 [(a)]** | |
| Oil | 96% to 101% of Brent |
| NGLs | 48% to 53% of Brent |
| Natural Gas | 110% to 120% of NYMEX |
| | |
| **2020 First Quarter Net Production, Capital and Income Statement Guidance** | |
| Net production (assumed Q1 average Brent price of $60/Bbl) | 119 to 124 MBOE per day |
| Net production (assumed Q1 average Brent price of $65/Bbl) | 118 to 123 MBOE per day |
| Capital [(b)] | $100 million to $125 million |
| Production costs (assumed Q1 average Brent price of $60/Bbl) | $18.35 to $19.45 per BOE |
| Production costs (assumed Q1 average Brent price of $65/Bbl) | $18.45 to $19.55 per BOE |
| Adjusted general and administrative expenses [(c) & (d)] | $5.70 to $6.10 per BOE |
| Depreciation, depletion and amortization [(c)] | $10.05 to $10.35 per BOE |
| Taxes other than on income | $38 million to $42 million |
| Exploration expense | $3 million to $8 million |
| Interest expense [(e)] | $87 million to $92 million |
| Cash interest [(e)] | $64 million to $69 million |
| Effective tax rate | 0% |
| Cash tax rate | 0% |
| | |
| **Pre-tax 2020 First Quarter Price Sensitivities [(f)]** | |
| $1 change in Brent index - Oil [(g)] | $5.6 million |
| $1 change in Brent index - NGLs | $0.7 million |
| $0.50 change in NYMEX - Gas | $6.0 million |

(a) Realizations exclude hedge effects.

(b) Capital guidance includes CRC, MIRA and Alpine capital.

(c) Production based on assumed Q1 average Brent price of $60/Bbl.

(d) A portion of our long-term incentive compensation programs are stock based but payable in cash. Accounting rules require that we adjust our obligation for all vested but unpaid cash-settled awards under these programs to the amount that would be paid using our stock price as of the end of each reporting period. Therefore, in addition to the normal pro-rata vesting expense associated with these programs, our quarterly expense could include a cumulative adjustment depending on movement in our stock price. Our stock price used to set Q1 2020 guidance was $9.03 per share, in line with the price on December 31, 2019. As a result no cash-based equity compensation cumulative adjustment has been incorporated into our guidance.

(e) 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 lower than interest expense due to the timing of interest payments.

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

(g) Amount reflects the sensitivity assuming no hedged barrels. We have downside price protection on 40% of our Q1 2020 oil production, at a weighted-average Brent floor price of $71 per barrel until Brent falls below $57, when we receive Brent plus $14 per barrel.