California Resources Corporation Announces Third Quarter 2019 Results

October 31, 2019

LOS ANGELES--(BUSINESS WIRE)-- California Resources Corporation (NYSE: CRC), an independent California-based oil and gas exploration and production company, today reported net income attributable to common stock of $94 million, or $1.89 per diluted share, for the third quarter of 2019. Adjusted net income[1] was $17 million, or $0.35 per diluted share. Operational and financial highlights for the third quarter of 2019 were as follows:

Third Quarter Highlights

- Reported adjusted EBITDAX[1] of $278 million; adjusted EBITDAX margin[1] of 41%; net cash provided by operating activities of $268 million; free cash flow[1] of $151 million after taking into account CRC's internally funded capital.
- Implemented a more efficient organizational design, resulting in anticipated ongoing annual cost savings of approximately $50 million starting in the fourth quarter of 2019
- Delivered average production of 128,000 barrels of oil equivalent (BOE) per day including 79,000 barrels per day of oil
- Invested $188 million of total capital, including $117 million of internally funded capital
- Drilled 82 wells in the San Joaquin basin, 8 wells in the Los Angeles basin and 1 exploratory well in the Ventura basin, including JV wells
- Repurchased $153 million face value of Second Lien Notes for $90 million
- Secured a credit agreement amendment to provide future flexibility in connection with potential royalty transactions

Todd Stevens, CRC's President and Chief Executive Officer, said, "CRC's start to the second half of the year highlights our continued focus on controlling what we can control by maintaining capital discipline, opportunistically repurchasing debt to strengthen our balance sheet, improving our credit position, reducing costs and enhancing margins. Our previously announced JV partnership with Alpine ramped up quickly, having drilled 52 wells through the end of the third quarter, with the majority of the wells being accretive to production beginning in the fourth quarter. We were also excited to receive a grant from the Department of Energy for a FEED study to advance CO_2 capture and sequestration at Elk Hills, which could potentially add well over 150 MMBOE of EOR reserves, reduce our greenhouse gas emissions and in turn lower costs."

Mr. Stevens continued, "Additionally, we are pleased we were able to repurchase over $150 million face value of our Second Lien Notes at a significant discount as well as secure our ninth credit amendment during the quarter. We remain committed to pursuing additional transactions to progress towards our balance sheet goals while driving value through a balanced approach of debt repurchases with investments in our large project inventory."

Third Quarter 2019 Results

For the third quarter of 2019, CRC reported net income attributable to common stock (CRC net income) of $94 million, or $1.89 per diluted share, compared to $66 million, or $1.32 per diluted share, for the same period of 2018. Adjusted net income[1] for the third quarter of 2019 was $17 million, or $0.35 per diluted share, compared to $41 million, or $0.81 per diluted share, for the same period in 2018. Adjusted net income[1] excluded a net gain of $82 million on debt repurchases, non-cash losses on commodity derivatives of $6 million and income of $1 million, net, for other unusual and infrequent items.

Adjusted EBITDAX[1] for the third quarter of 2019 was $278 million and cash provided by operating activities was $268 million.

Total daily production volumes decreased 6% year-over-year, from 136,000 BOE per day for the third quarter of 2018 to 128,000 BOE per day for the third quarter of 2019. Oil volumes in the third quarter of 2019 averaged 79,000 barrels per day, NGL volumes averaged 16,000 barrels per day and gas volumes averaged 196,000 thousand cubic feet (Mcf) per day. The decrease was due to the Lost Hills divestiture, lower capital investment including fewer workovers, power outages and other factors. The divestiture reduced our third quarter 2019 production by over 2,000 BOE per day compared to the same quarter of 2018.

Despite lower Brent index prices, our realized crude oil prices, including the effect of settled hedges, increased by $4.78 per barrel from $63.63 in the third quarter of 2018 to $68.41 per barrel in the third quarter of 2019. In the third quarter of 2019, hedge settlements increased our realized crude oil prices by $5.56 per barrel compared to a reduction of $10.10 per barrel in the same prior-year period. Realized NGL prices were $23.55 per barrel, down $22.17 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 $2.73 per Mcf for the third quarter of 2019, $0.43 per Mcf lower than the same prior-year period due to milder temperatures and more pipeline availability within local California markets in 2019 compared to 2018.

Production costs for the third quarter of 2019 were $221 million, compared to $236 million for the third quarter of 2018. On a per barrel basis, for the same comparative periods, production costs were $18.82 and $18.92, respectively. The decrease is primarily due to cost savings from the Lost Hills divestiture, lower surface operations costs, lower field employee-related costs and lower downhole maintenance spending, partially offset by higher energy prices. Excluding the effect of PSC-type contracts, production costs on a per barrel basis for the same comparative periods would have been $17.44 and $17.55, respectively.

General and administrative (G&A) expenses were $66 million for the third quarter of 2019, compared to $81 million for the same prior-year period. The decrease was primarily attributable to a lower stock price resulting in a $13 million decrease in cash-settled stock-based compensation expense.

CRC reported taxes other than on income of $42 million for the third quarter of 2019, compared to $45 million for the same prior-year period. Exploration expense was $5 million for the third quarter of 2019, $1 million higher than the same prior-year period.

Total capital invested during the quarter of 2019 was $188 million, within our guidance. CRC internally funded $117 million, of which $101 million was directed to drilling and capital workovers. CRC's JV partner Benefit Street Partners (BSP) also invested $5 million, which is included in CRC's consolidated results. CRC's JV partners Macquarie Infrastructure and Real Assets Inc. (MIRA) and Alpine Energy Capital, LLC (Alpine) invested an additional $3 million and $63 million, respectively, which are excluded from CRC's consolidated results.

Cash provided by operating activities for the third quarter of 2019 was $268 million and free cash flow[1] was $151 million after taking into account CRC's internally funded capital.

Nine-Month Results

For the first nine months of 2019, CRC net income was $39 million, or $0.77 per diluted share, compared to a net loss attributable to common stock of $18 million, or $0.38 per diluted share, for the same period of 2018. Including hedge settlements, the 2019 results reflected higher year-over-year revenue despite a lower oil price environment. Adjusted net income[1] for the first nine months of 2019 was $34 million, or $0.69 per diluted share, compared with an adjusted net income[1] of $35 million, or $0.71 per diluted share, for the same period of 2018. The 2019 adjusted net income[1] excluded $99 million of non-cash derivative losses, a net gain of $108 million from debt repurchases and a net $4 million charge related to other unusual and infrequent items.

Total daily production volumes averaged 130,000 BOE per day for the first nine months of 2019, compared with 131,000 BOE per day for the same period in 2018, a decrease of 1 percent. The 2018 volumes reflect two quarters of production from the Elk Hills acquisition. The 2019 volumes reflect the effect of the strategic Lost Hills divestiture that occurred in the second quarter of 2019.

In the first nine months of 2019, realized crude oil prices, including the effect of settled hedges, increased $4.63 per barrel to $68.16 per barrel from $63.53 per barrel for the same period in 2018. Settled hedges increased 2019 realized crude oil prices by $3.13 per barrel, compared with a reduction of $8.00 per barrel for the same period in 2018. Realized NGL prices decreased 29 percent, or $12.67 per barrel to $31.04 per barrel in the first nine months of 2019 from $43.71 per barrel for the same period of 2018. Realized natural gas prices increased $0.09 per Mcf to $2.82 per Mcf, compared with $2.73 per Mcf for the same period in 2018, largely due to stronger California demand.

Production costs for the first nine months of 2019 were $684 million, or $19.32 per BOE, compared to $679 million, or $18.98 per BOE, for the same period in 2018. The increase in production costs was primarily attributable to the Elk Hills transaction, higher surface operations and maintenance costs, energy costs and other items, partially offset by lower downhole maintenance activity and lower costs resulting from the Lost Hills divestiture. Per unit production costs, excluding the effect of PSCs[1], were $17.82 and $17.48 per BOE for the first nine months of 2019 and 2018, respectively.

G&A expenses for the first nine months of 2019 were $228 million, compared to $234 million in the prior-year period, with the decrease largely due to lower equity compensation expense in the first nine months of 2019. This decrease was partially offset by higher expenses across a number of functions.

Taxes other than on income of $119 million for the first nine months of 2019 were comparable to the same period of 2018, when taxes were $120 million. Exploration expense of $25 million for the first nine months of 2019 was $7 million higher than the same period of 2018.

CRC's internally funded capital investment in the first nine months of 2019 totaled $345 million, of which $259 million was directed to drilling and capital workovers. CRC's JV partners invested $121 million in the first nine months of 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 first nine months of 2019 was $540 million and free cash flow[1] was $195 million after taking into account CRC's internally funded capital.

Operational Update

In the third quarter of 2019, CRC operated an average of ten drilling rigs, with 3 on primary, 3 on waterfloods and 4 on unconventional production. With total invested capital, we drilled 90 development wells (47 primary, 27 waterflood, and 16 unconventional) and one exploration well. 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 94,000 BOE per day and operated seven rigs. The Los Angeles basin contributed 24,000 BOE per day of production and operated two rigs directed toward waterflood projects. The Ventura basin produced 5,000 BOE per day and operated one rig focused on exploration and the Sacramento basin, where we had no active CRC drilling program, produced 5,000 BOE per day.

2019 Capital Budget

CRC expects its 2019 internally funded capital program will range from $385 million to $400 million, of which $345 million has been invested through the third quarter of 2019. We have front loaded our internally funded capital investments for 2019. With additional investment from new and existing JV partners, CRC anticipates JV investment of $200 to $225 million for 2019, of which $121 million has been invested through the third quarter of 2019. CRC anticipates a total capital program of approximately $585 to $625 million for the year. Our 2019 capital is focused on oil and largely directed to short payout projects, such as primary drilling of both vertical and lateral wells, capital workovers and low-risk projects including waterflood and steamflood investments that maintain base production.

Recent Joint Venture

In July 2019, we entered into a development agreement with Alpine to develop portions of CRC's Elk Hills field. Alpine is a joint venture between subsidiaries of Colony Capital, Inc. (Colony) and Equity Group Investments. Alpine committed to invest $320 million, which may be increased to a total investment of $500 million, subject to the mutual agreement of the parties. The initial commitment will cover multiple development opportunities and is intended to be invested over approximately three years in accordance with a 275-well development plan. Alpine will fund 100% of the development wells and will earn a 90% working interest in those wells. If Alpine receives an agreed upon return, CRC's working interest in those wells will increase from 10% to 82.5%.

In connection with this joint venture, Colony received a warrant to purchase up to 1.25 million shares of CRC's common stock, at an exercise price of $40 per share.

Repurchases and Balance Sheet Update

During the third quarter of 2019, CRC repurchased $153 million in face value of Second Lien Notes for $90 million, bringing the aggregate face value repurchased since issuance to $412 million, including $229 million during the first nine months of 2019. Net debt outstanding at the end of the third quarter was under $5.0 billion. CRC also secured a ninth amendment to our credit agreement which provides future flexibility in connection with potential royalty transactions.

The semi-annual borrowing base review under the Company's 2014 Revolving Credit Facility is finalized in early May and early November of each year. The process is currently underway and is well advanced.

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 fourth quarter of 2019, CRC has protected the downside price risk on 35,000 barrels per day at approximately $76 Brent with put spreads. These put spreads provide full upside to oil price movements and downside protection when Brent drops below $60 per barrel, at which point we receive Brent plus approximately $16 per barrel. For the first and second quarters of 2020, CRC has protected the downside risk of 30,000 and 15,000 barrels per day at approximately $71 Brent and $68 Brent, respectively. These put spreads provide downside price protection when Brent prices drop below $57 and $55 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 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 10,000 and 5,000 barrels per day, respectively, at $65 per barrel. These put spreads provide downside protection when Brent prices drop below $55, at which point CRC receives Brent plus approximately $10 per barrel. See Attachment 8 for more details.

[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, including reconciliations to their most directly comparable GAAP measure, where applicable.

Conference Call Details

To participate in Monday's conference call scheduled for November 4th, 2019 at 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/10134619. 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 CRC's capital plan, planned investments, debt repurchases and distributions to JV partners
- 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, 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, including as a result of lender restrictions, 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, transportation or storage constraints, natural disasters, 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.

Attachment 1
SUMMARY OF RESULTS

($ and shares in millions, except per share amounts)	Third Quarter **2019**	Third Quarter 2018	Nine Months **2019**	Nine Months 2018
Statements of Operations:				
Revenues and Other				
Oil and gas sales	**$ 541**	$ 700	**$1,720**	$1,932
Net derivative gain (loss) from commodity contracts	**37**	(54)	**(31)**	(259)

Other revenue	**103**	182	**335**	313
Total revenues and other	**681**	828	**2,024**	1,986
Costs and Other				
Production costs	**221**	236	**684**	679
General and administrative expenses	**66**	81	**228**	234
Depreciation, depletion and amortization	**118**	128	**357**	372
Taxes other than on income	**42**	45	**119**	120
Exploration expense	**5**	4	**25**	18
Other expenses, net	**81**	149	**284**	259
Total costs and other	**533**	643	**1,697**	1,682
Operating Income	**148**	185	**327**	304
Non-Operating (Loss) Income				
Interest and debt expense, net	**(95)**	(95)	**(293)**	(281)
Net gain on early extinguishment of debt	**82**	2	**108**	26
Gain on asset divestitures	**—**	3	**—**	4
Other non-operating expenses	**(8)**	(4)	**(18)**	(16)
Income Before Income Taxes	**127**	91	**124**	37
Income tax	**—**	—	**—**	—
Net Income	**127**	91	**124**	37
Net income attributable to noncontrolling interests	**(33)**	(25)	**(85)**	(55)
Net Income (Loss) Attributable to Common Stock	**$ 94**	$ 66	**$ 39**	$ (18)
Net income (loss) attributable to common stock per share - basic	**$1.89**	$1.34	**$ 0.78**	$ (0.38)
Net income (loss) attributable to common stock per share - diluted	**$1.89**	$1.32	**$ 0.77**	$ (0.38)
Adjusted net income	**$ 17**	$ 41	**$ 34**	$ 35
Adjusted net income per share - basic	**$0.35**	$0.82	**$ 0.70**	$ 0.72
Adjusted net income per share - diluted	**$0.35**	$0.81	**$ 0.69**	$ 0.71
Weighted-average common shares outstanding - basic	**49.1**	48.5	**48.9**	47.0
Weighted-average common shares outstanding - diluted	**49.2**	49.1	**49.2**	47.0
Adjusted EBITDAX	**$ 278**	$ 308	**$ 834**	$ 803
Effective tax rate	**0%**	0%	**0%**	0%
Cash Flow Data:				
Net cash provided by operating activities	**$ 268**	$ 159	**$ 540**	$ 393
Net cash used in investing activities	**$(121)**	$(158)	**$ (291)**	$ (965)
Net cash (used) provided by financing activities	**$(152)**	$ (12)	**$ (244)**	$ 583

($ and shares in millions)	**September 30, 2019**	December 31, 2018
Selected Balance Sheet Data:		
Total current assets	**$ 510**	$ 640
Total property, plant and equipment, net	**$ 6,403**	$ 6,455
Total current liabilities	**$ 721**	$ 607
Long-term debt	**$ 4,896**	$ 5,251
Other long-term liabilities	**$ 679**	$ 575
Mezzanine equity	**$ 789**	$ 756
Equity	**$ (208)**	$ (247)
Outstanding shares	**49.1**	48.7

STOCK-BASED COMPENSATION

Our consolidated results of operations for the three months and nine months ended September 30, 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 over 50% 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:

	Third Quarter		Nine Months	
($ in millions, except per BOE amounts)	**2019**	2018	**2019**	2018
General and administrative expenses				
Cash-settled awards	**$ (2)**	$ 11	**$ 11**	$ 33
Equity-settled awards	**3**	2	**10**	10
Total in G&A	**$ 1**	$ 13	**$ 21**	$ 43
Total in G&A per Boe	**$ 0.09**	$ 1.04	**$ 0.59**	$ 1.20
Production costs				
Cash-settled awards	**$ —**	$ 2	**$ 4**	$ 8
Equity-settled awards	**1**	1	**3**	3
Total in production costs	**$ 1**	$ 3	**$ 7**	$ 11
Total in production costs per Boe	**$ 0.09**	$ 0.24	**$ 0.20**	$ 0.31
Total company	**$ 2**	$ 16	**$ 28**	$ 54
Total company per Boe	**$ 0.18**	$ 1.28	**$ 0.79**	$ 1.51

DERIVATIVE GAINS AND LOSSES

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

	Third Quarter		Nine Months	
($ millions)	**2019**	2018	**2019**	2018
Commodity Contracts:				
Non-cash derivative (loss) gain excluding noncontrolling interest	**$ (6)**	$ 28	**$ (99)**	$ (71)
Non-cash derivative gain (loss) - noncontrolling interest	**3**	(3)	**—**	(10)
Total non-cash changes	**(3)**	25	**(99)**	(81)
Net proceeds (payments) on settled commodity derivatives	**40**	(79)	**68**	(178)
Net derivative gain (loss) from commodity contracts	**$ 37**	$ (54)	**$ (31)**	$ (259)
Interest-Rate Contracts:				
Non-cash derivative gain (loss)	**$ —**	$ 1	**$ (4)**	$ —

Attachment 2

PRODUCTION STATISTICS

	Third Quarter		Nine Months	
Net Oil, NGLs and Natural Gas Production Per Day	**2019**	2018	**2019**	2018

Oil (MBbl/d)				
San Joaquin Basin	**51**	54	**53**	52
Los Angeles Basin	**24**	26	**24**	25
Ventura Basin	**4**	4	**4**	4
Total	**79**	84	**81**	81
NGLs (MBbl/d)				
San Joaquin Basin	**16**	16	**15**	16
Ventura Basin	**—**	1	**1**	1
Total	**16**	17	**16**	17
Natural Gas (MMcf/d)				
San Joaquin Basin	**162**	172	**163**	162
Los Angeles Basin	**2**	1	**2**	1
Ventura Basin	**4**	6	**6**	7
Sacramento Basin	**28**	29	**29**	30
Total	**196**	208	**200**	200
Total Production (MBoe/d)	**128**	136	**130**	131

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.

Attachment 3

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.

	Third Quarter		Nine Months	
($ millions, except per share amounts)	**2019**	2018	**2019**	2018
Net income	**$ 127**	$ 91	**$ 124**	$ 37
Net income attributable to noncontrolling interests	**(33)**	(25)	**(85)**	(55)
Net income (loss) attributable to common stock	**94**	66	**39**	(18)
Unusual, infrequent and other items:				
Non-cash derivative (gain) loss from commodities, excluding noncontrolling interest	**6**	(28)	**99**	71

Severance costs	**—**	—	**2**	4
Gain on asset divestitures	**—**	(3)	**—**	(4)
Net gain on early extinguishment of debt	**(82)**	(2)	**(108)**	(26)
Other, net	**(1)**	8	**2**	8
Total unusual, infrequent and other items	**(77)**	(25)	**(5)**	53
Adjusted net income	**$ 17**	$ 41	**$ 34**	$ 35
Net income (loss) attributable to common stock per share - diluted	**$ 1.89**	$ 1.32	**$ 0.77**	$ (0.38)
Adjusted net income per share - diluted	**$ 0.35**	$ 0.81	**$ 0.69**	$ 0.71

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.

	Third Quarter		Nine Months	
($ millions)	**2019**	2018	**2019**	2018
Net cash provided by operating activities	**$ 268**	$ 159	**$ 540**	$ 393
Capital investments	**(122)**	(177)	**(393)**	(504)
Free cash flow	**146**	(18)	**147**	(111)
BSP funded capital	**5**	19	**48**	37
Free cash flow, after internally funded capital	**$ 151**	$ 1	**$ 195**	$ (74)

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.

	Third Quarter		Nine Months	
($ millions, except per BOE amounts)	**2019**	2018	**2019**	2018
Net income	**$ 127**	$ 91	**$ 124**	$ 37
Interest and debt expense, net	**95**	95	**293**	281
Depreciation, depletion and amortization	**118**	128	**357**	372
Exploration expense	**5**	4	**25**	18
Unusual, infrequent and other items [(a)]	**(77)**	(25)	**(5)**	53
Other non-cash items	**10**	15	**40**	42
Adjusted EBITDAX	**$ 278**	$ 308	**$ 834**	$ 803
Net cash provided by operating activities	**$ 268**	$ 159	**$ 540**	$ 393
Cash interest	**75**	69	**300**	284
Exploration expenditures	**5**	4	**15**	14
Working capital changes	**(70)**	76	**(21)**	113
Other, net	**—**	—	**—**	(1)
Adjusted EBITDAX	**$ 278**	$ 308	**$ 834**	$ 803
Adjusted EBITDAX per Boe	**$ 23.68**	$ 24.70	**$ 23.55**	$ 22.44

(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.

	Third Quarter		Nine Months	
($ millions)	**2019**	2018	**2019**	2018
Adjusted EBITDAX	**$ 278**	$ 308	**$ 834**	$ 803
Cash interest	**(75)**	(69)	**(300)**	(284)
Distributions paid to noncontrolling interest holders:				
BSP JV	**(30)**	(18)	**(55)**	(35)
Ares JV	**(20)**	(21)	**(60)**	(45)
Discretionary cash flow	**$ 153**	$ 200	**$ 419**	$ 439

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.

	Third Quarter		Nine Months	
($ millions)	**2019**	2018	**2019**	2018
Total revenues and other	**$ 681**	$ 828	**$ 2,024**	$ 1,986
Non-cash derivative gain (loss)	**3**	(25)	**99**	81
Revenues, excluding non-cash derivative gains and losses	**$ 684**	$ 803	**$ 2,123**	$ 2,067
Adjusted EBITDAX Margin	**41%**	38%	**39%**	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.

	Third Quarter		Nine Months	
	2019	2018	**2019**	2018
General and administrative expenses	**$ 66**	$ 81	**$ 228**	$ 234
Severance costs and other	**(1)**	—	**(2)**	(1)
Adjusted general and administrative expenses	**$ 65**	$ 81	**$ 226**	$ 233

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.

	Third Quarter		Nine Months	
($ per Boe)	**2019**	2018	**2019**	2018
Production costs	**$ 18.82**	$ 18.92	**$ 19.32**	$ 18.98
Excess costs attributable to PSC-type contracts	**(1.38)**	(1.37)	**(1.50)**	(1.50)
Production costs, excluding effects of PSC-type contracts	**$ 17.44**	$ 17.55	**$ 17.82**	$ 17.48

Attachment 4

CAPITAL INVESTMENTS

($ millions)	Third Quarter **2019**	Third Quarter 2018	Nine Months **2019**	Nine Months 2018
Internally funded capital	**$ 117**	$ 158	**$345**	$467
BSP funded capital	**5**	19	**48**	37
Capital investments - as reported	**$ 122**	$ 177	**$393**	$504
MIRA funded capital	**3**	19	**10**	46
Alpine funded capital	**63**	—	**63**	—
Total capital program	**$ 188**	$ 196	**$466**	$550

Attachment 5

PRICE STATISTICS

	Third Quarter **2019**	Third Quarter 2018	Nine Months **2019**	Nine Months 2018
Realized Prices				
Oil with hedge ($/Bbl)	**$68.41**	$63.63	**$68.16**	$63.53
Oil without hedge ($/Bbl)	**$62.85**	$73.73	**$65.03**	$71.53
NGLs ($/Bbl)	**$23.55**	$45.72	**$31.04**	$43.71
Natural gas ($/Mcf)	**$ 2.73**	$ 3.16	**$ 2.82**	$ 2.73
Index Prices				
Brent oil ($/Bbl)	**$62.00**	$75.97	**$64.74**	$72.68
WTI oil ($/Bbl)	**$56.45**	$69.50	**$57.06**	$66.75
NYMEX gas ($/MMBtu)	**$ 2.27**	$ 2.88	**$ 2.72**	$ 2.83
Realized Prices as Percentage of Index Prices				
Oil with hedge as a percentage of Brent	**110%**	84%	**105%**	87%
Oil without hedge as a percentage of Brent	**101%**	97%	**100%**	98%
Oil with hedge as a percentage of WTI	**121%**	92%	**119%**	95%
Oil without hedge as a percentage of WTI	**111%**	106%	**114%**	107%
NGLs as a percentage of Brent	**38%**	60%	**48%**	60%
NGLs as a percentage of WTI	**42%**	66%	**54%**	65%
Natural gas as a percentage of NYMEX	**120%**	110%	**104%**	96%

Attachment 6

THIRD QUARTER DRILLING ACTIVITY

Wells Drilled	**San Joaquin Basin**	**Los Angeles Basin**	**Ventura Basin**	**Sacramento Basin**	**Total**
Development Wells					
Primary	47	—	—	—	47
Waterflood	19	8	—	—	27
Steamflood	—	—	—	—	—
Unconventional	16	—	—	—	16
Total	82	8	—	—	90

Exploration Wells					
Primary	—	—	1	—	1
Waterflood	—	—	—	—	—
Steamflood	—	—	—	—	—
Unconventional	—	—	—	—	—
Total	—	—	1	—	1
Total Wells [(a)]	82	8	1	—	91
CRC wells drilled	29	5	1	—	35
BSP wells drilled	1	3	—	—	4
MIRA wells drilled	—	—	—	—	—
Alpine wells drilled	52	—	—	—	52

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

Attachment 7

NINE MONTHS 2019 DRILLING ACTIVITY

Wells Drilled	**San Joaquin Basin**	**Los Angeles Basin**	**Ventura Basin**	**Sacramento Basin**	**Total**
Development Wells					
Primary	53	—	—	—	53
Waterflood	34	22	—	—	56
Steamflood	40	—	—	—	40
Unconventional	32	—	—	—	32
Total	159	22	—	—	181
Exploration Wells					
Primary	2	—	2	—	4
Waterflood	—	—	—	—	—
Steamflood	5	—	—	—	5
Unconventional	—	—	—	—	—
Total	7	—	2	—	9
Total Wells [(a)]	166	22	2	—	190
CRC wells drilled	98	14	2	—	114
BSP wells drilled	15	8	—	—	23
MIRA wells drilled	1	—	—	—	1
Alpine wells drilled	52	—	—	—	52

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

Attachment 8

HEDGES - CURRENT

	Q4 2019	**Q1 2020**	**Q2 2020**	**Q3 2020**	**Q4 2020**
CRUDE OIL					
Purchased Puts:					

Barrels per day	35,000	30,000	15,000	10,000	5,000
Weighted-average Brent price per barrel	$75.71	$70.83	$68.33	$65.00	$65.00
Sold Puts:					
Barrels per day	35,000	30,000	150,000	10,000	5,000
Weighted-average Brent price per barrel	$60.00	$56.67	$55.00	$55.00	$55.00
Swaps:					
Barrels per day	—	—	5,000[(a)]	—	—
Weighted-average Brent price per barrel	$ —	$ —	$70.05	$ —	$ —

(a) Counterparties have the option to increase swap volumes by up to 5,000 barrels per day at a weighted-average Brent price of $70.05 for the second quarter of 2020.

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.

Attachment 9

2019 FOURTH QUARTER GUIDANCE

Anticipated Realizations Against the Prevailing Index Prices for Q4 2019 [(a)]	
Oil	96% to 101% of Brent
NGLs	40% to 45% of Brent
Natural Gas	110% to 120% of NYMEX
2019 Fourth Quarter Production, Capital and Income Statement Guidance	
Production (assumed Q4 average Brent price of $60/Bbl)	124 to 129 MBOE per day
Production (assumed Q4 average Brent price of $65/Bbl)	123 to 128 MBOE per day
Capital [(b)]	$135 million to $165 million
Production costs (assumed Q4 average Brent price of $60/Bbl)	$17.70 to $18.80 per BOE
Production costs (assumed Q4 average Brent price of $65/Bbl)	$17.80 to $18.90 per BOE
Adjusted general and administrative expenses [(c) & (d)]	$5.70 to $6.10 per BOE
Depreciation, depletion and amortization [(c)]	$10.15 to $10.45 per BOE
Taxes other than on income	$38 million to $42 million
Exploration expense	$4 million to $9 million
Interest expense [(e)]	$88 million to $93 million
Cash interest [(e)]	$139 million to $144 million
Effective tax rate	0%
Cash tax rate	0%
Pre-tax 2019 Fourth Quarter Price Sensitivities [(f)]	
$1 change in Brent index - Oil [(g)]	$6.5 million
$1 change in Brent index - NGLs	$0.7 million
$0.50 change in NYMEX - Gas	$7.0 million

(a) Realizations exclude hedge effects.
(b) Capital guidance includes CRC, MIRA and Alpine capital.
(c) Production based on assumed Q4 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. For example, the third quarter of 2019 reflected an $8 million reduction of our G&A costs as a result of lower stock price from the second quarter. Our stock price used to set Q4 2019 guidance was $10.20 per share, in line with the price on September 30, 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 higher 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 44% of our Q4 2019 oil production, at a weighted-average Brent floor price of $76 per barrel until Brent falls below $60, when we receive Brent plus $16 per barrel.

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