NEWS RELEASE

For immediate release

California Resources Corporation Announces Third Quarter 2018 Results

LOS ANGELES, November 1, 2018 - California Resources Corporation (NYSE:CRC), an independent California-based oil and gas exploration and production company, today reported net income attributable to common stock (CRC net income) of $66 million, or $1.32 per diluted share, for the third quarter of 2018. Adjusted net income[1] for the third quarter of 2018 was $41 million, or $0.81 per diluted share.

Quarterly Highlights Include:

- Generated core adjusted EBITDAX[1] of $400 million, which excludes the impact of $79 million of cash settlement payments on commodity hedge contracts and $13 million of cash-settled stock-based compensation expense
- Reported adjusted EBITDAX[1] of $308 million, 26% higher than the prior quarter, and an adjusted EBITDAX margin[1] of 38%
- Produced 136,000 BOE per day, which reflects an increase of 6% over the prior year period and the midpoint of the previous guidance range
- Invested $196 million of total capital of which internally funded capital was $158 million
- Drilled 59 wells with internally funded capital and 36 wells with joint venture (JV) capital
- Realized $34 million of annualized synergies after the Elk Hills acquisition, exceeding the initial $20 million target well ahead of anticipated pace
- Increased 2018 capital budget to a range of $720 to $750 million, including approximately $100 million of JV funding, to sustain the increased level of activity through the fourth quarter
- Issued fourth quarter of 2018 production guidance of 136,000 to 139,000 BOE per day reflecting continued production growth

Todd A. Stevens, CRC's President and Chief Executive Officer, said, "CRC‘s value-driven strategy continued to deliver strong results for the third quarter of 2018, showcasing operational excellence, strong Brent-based realizations, effective capital deployment and portfolio de-risking with the execution of two joint ventures. This resulted in the highest level of quarterly adjusted EBITDAX since 2014 and demonstrated our ability to deliver positive free cash flow before working capital on a year-to-date basis. We remain dedicated to capturing the full value of our conventional resources and driving production growth from our diverse portfolio of assets, while strengthening our financial position and furthering debt reduction efforts. Looking ahead, we are focused on a strong finish to 2018 and carrying that momentum into 2019."

Third Quarter 2018 Results

For the third quarter of 2018, CRC net income was $66 million, or $1.32 per diluted share, while adjusted net income[1] was $41 million, or $0.81 per diluted share. Adjusted net income[1] excluded $28 million of non-cash derivative gains, a $3 million gain on asset divestitures, a net gain of $2 million on debt repurchases and a net $8 million charge related to other unusual and infrequent items. These results compared to a net loss of $133 million, or $3.11 per diluted share, and an adjusted net loss of $52 million, or $1.22 per diluted share, in the same prior year period. The 2018 results reflected higher production, significantly higher realized commodity prices and higher gas trading income, partially offset by higher production costs and general and administrative (G&A) expenses.

Total daily production volumes averaged 136,000 barrels of oil equivalent (BOE) per day for the third quarter of 2018, compared to 128,000 BOE per day for the same period in 2017, an increase of more than 6 percent over the prior year period, largely driven by the Elk Hills acquisition. This net increase included a 1,300 BOE per day negative effect on production volumes from production sharing contracts (PSC). For the third quarter of 2018 oil volumes averaged 84,000 barrels per day, NGL volumes averaged 17,000 barrels per day and gas volumes averaged 208,000 thousand cubic feet (MCF) per day.

Realized crude oil prices, including the effect of settled hedges, increased by $13.61 per barrel in the third quarter of 2018 to $63.63 per barrel from the comparable prior year period. Settled hedges decreased realized crude oil prices by $10.10 per barrel in the third quarter of 2018. Average realized NGL prices continued to be strong and registered $45.72 per barrel, reflecting a realized price that was 60 percent of Brent prices. Realized natural gas prices were $3.16 per MCF in the third quarter of 2018, $0.60 higher than in the same prior year period and $0.91 higher than in the second quarter of 2018. The increase in realized gas prices is largely due to higher price realizations resulting from limited third-party storage, pipeline constraints and seasonality trends.

Production costs for the third quarter of 2018 were $236 million compared to $222 million in the third quarter of 2017, an increase of $14 million primarily due to $12 million from the Elk Hills acquisition and increased equity compensation expense of $2 million primarily resulting from the Company's higher stock price. On a per unit basis, third quarter of 2018 production costs were $18.92 per BOE compared to $18.90 per BOE in the comparable prior year period. Third quarter of 2018 unit production costs were below the midpoint of previously disclosed guidance and would have been $18.68 per BOE excluding equity compensation expense of $0.24 per BOE. In line with industry practice for companies operating under PSCs, CRC reports gross field operating costs but only the Company's share of production volumes, which can result in higher production costs per barrel. Excluding this PSC effect, per unit production costs[1] for the third quarter of 2018 would have been $17.55 per BOE. General and administrative expenses of $81 million for the third quarter of 2018 were $20 million higher than the comparable prior year period primarily related to higher equity compensation expense of $9 million as a result of CRC's increased stock price and additional G&A of $3 million as a result of the Elk Hills acquisition. The remaining increase in G&A expenses was the result of a number of smaller increases in various cost categories.

CRC reported taxes other than on income of $45 million, $6 million higher than the same prior year period largely due to higher property taxes as a result of commodity price increases. Exploration expense was $4 million for the third quarter of 2018, $1 million lower than the comparable prior year period.

Capital investment in the third quarter of 2018 totaled $158 million, excluding JV capital. Approximately $136 million was directed to drilling and capital workovers.

Cash provided by operating activities was $159 million, which included interest payments of $69 million. CRC's free cash flow[1], excluding BSP funded capital of $19 million, was $1 million in the third quarter of 2018.

Nine-Month Results

For the first nine months of 2018, CRC net loss was $18 million, or $0.38 per diluted share, compared to net loss of $128 million, or $3.01 per diluted share, for the same period of 2017. The 2018 results reflected significantly higher realized oil and NGL prices, partially offset by higher production costs and higher G&A expense. Adjusted net income[1] for the first nine months of 2018 was $35 million, or $0.71 per diluted share, compared with an adjusted net loss of $173 million, or $4.07 per diluted share, for the same prior year period. The 2018 adjusted net income excluded $71 million of non-cash derivative losses, a net gain of $26 million on debt repurchases, a $4 million gain on asset divestitures and a net $12 million charge related to other unusual and infrequent items. The 2017 adjusted net loss excluded $38 million of non-cash derivative gains, $21 million of gains from asset divestitures, a $4 million net gain on debt repurchases and an $18 million charge from other unusual and infrequent items.

Total daily production volumes averaged 131,000 BOE per day in the first nine months of 2018 compared with 130,000 BOE per day for the same period of 2017. This increase included a negative effect on production volumes from PSCs of 1,800 BOE per day. Excluding production from the Elk Hills acquisition and the effect of PSCs, the decline from the first nine months of 2017 to the first nine months of 2018 was 4 percent. This low decline reflects the gradual ramp up in capital investment beginning in late 2017.

In the first nine months of 2018, realized crude oil prices, including the effect of settled hedges, increased $14.11 per barrel to $63.53 per barrel from $49.42 per barrel for the same prior year period. Settled hedges reduced 2018 realized crude oil prices by $8.00 per barrel compared with an increase of $0.66 per barrel for the same period of 2017. Realized NGL prices increased 32 percent to $43.71 from $33.00 per barrel in the first nine months of 2017. Realized natural gas prices increased 3 percent to $2.73 per MCF compared with $2.64 per MCF for the comparable prior year period.

Production costs for the first nine months of 2018 were $679 million, or $18.98 per BOE, compared to $649 million, or $18.31 per BOE, for the same period in 2017. The Elk Hills acquisition added $24 million to the first nine months' production costs and the increase in equity compensation expense added $8 million, or $0.23 per BOE. Excluding these items, production costs were slightly lower in the current year compared to the prior year due to ongoing efficiency efforts. Per unit production costs, excluding the effect of PSC contracts, were $17.48 and $17.21 per BOE for the first nine months of 2018 and 2017, respectively. G&A expenses were $234 million and $183 million for the first nine months of 2018 and 2017, respectively, with the difference primarily related to increased equity compensation expense resulting from the Company's higher stock price and additional G&A expense as a result of the Elk Hills acquisition.

Taxes other than on income of $120 million for the first nine months of 2018 were $17 million higher than the same period of 2017 primarily due to higher property taxes as a result of commodity price increases. Exploration expense of $18 million for the first nine months of 2018 was $1 million higher than the comparable year period of 2017.

Capital investment in the first nine months of 2018 totaled $467 million, excluding JV capital, of which $363 million was directed to drilling and capital workovers.

Cash provided by operating activities for the first nine months of 2018 was $393 million and free cash flow, excluding BSP funded capital of $37 million, was $(74) million. Excluding changes in working capital, which predominantly relate to greenhouse gas payments for prior years' activities, free cash flow would have been $17 million.

Operational Update

CRC operated an average of 10 drilling rigs during the third quarter of 2018 with two rigs focused on steamfloods, four on waterfloods, two on conventional primary production, one on unconventional production and one on exploration. CRC drilled 94 development wells and one exploration well with CRC and JV capital (43 steamflood, 25 waterflood, 18 primary and 9 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. In the San Joaquin basin, CRC operated seven rigs and produced approximately 99,000 BOE per day in the third quarter of 2018. The Los Angeles basin operated three rigs directed toward waterflood projects and contributed 26,000 BOE per day of production in the third quarter of 2018. The Ventura basin produced 6,000 BOE per day and the Sacramento basin produced 5,000 BOE per day. Neither the Ventura nor Sacramento basin had active drilling programs in the third quarter of 2018.

2018 Capital Budget

CRC increased its 2018 capital program to a range of $720 million to $750 million, which includes approximately $100 million of JV capital. This increase from the previously stated range of $650 million to $700 million is intended to build on the momentum created in the first nine months of 2018. The updated program reflects management's strategy to align the capital program with stronger expected cash flows from commodity price improvements and increased production from the Elk Hills acquisition. The additional capital will sustain current workover and facility activity through the fourth quarter of 2018.

Debt Reduction Update

CRC continues to deliver on its commitment to strengthen the balance sheet. In the third quarter of 2018, CRC repurchased a total of $32 million in aggregate principal amount of the Company's outstanding debt for $30 million in cash. Through the first nine months of 2018, CRC repurchased a total of $177 million in aggregate principal amount of the Company's outstanding debt for $149 million in cash. The majority of CRC's debt repurchases focused on the Company's Second Lien Notes.

Borrowing Base Redetermination

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

Mid-Year Reserves

CRC's mid-year proved reserves totaled 731 MMBOE, up from 618 MMBOE at year-end 2017. Excluding positive price revisions and additions related to the Elk Hills acquisition, the Company organically replaced 96% of proved reserves. This strong organic reserve replacement ratio (RRR) was achieved with well executed capital programs in Buena Vista, South Valley, Huntington Beach and Long Beach. Approximately 23 MMBOE of additions were related to transfers, revisions, extensions and discoveries and improved recovery. The Elk Hills acquisition added 63 MMBOE of proved reserves, in line with the estimate stated at the time of acquisition.

Hedging Update

CRC continues to opportunistically seek hedging transactions to protect its cash flow, operating margins and capital program while maintaining adequate liquidity. For the first and second quarters of 2019, CRC has protected the downside price risk of approximately 47,000 and 42,000 barrels per day at approximately $65.35 Brent and $68.91 Brent per barrel, respectively. In the third and fourth quarters of 2019, the Company protected the downside price risk of approximately 42,000 and 37,000 barrels per day at approximately $72.18 and $74.56 Brent per barrel, respectively. Except for a small portion primarily in the first quarter of 2019, the 2019 hedges do not contain caps, thereby providing upside to oil price movements. See Attachment 8 for more details.

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

Conference Call Details

To participate in today's conference call scheduled for 5:00 P.M. Eastern Daylight Time, either dial (877) 328-5505 (International calls please dial +1 (412) 317-5421) or access via webcast at www.crc.com, fifteen minutes prior to the scheduled start time to register. Participants may also pre-register for the conference call at http://dpregister.com/10124828. A digital replay of the conference call will be archived for approximately 30 days and supplemental slides for the conference call will be available online in the Investor Relations section of www.crc.com.

About California Resources Corporation

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

Forward-Looking Statements

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

- financial position, liquidity, cash flows and results of operations
- business prospects
- transactions and projects
- operating costs
- 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 we believe assumptions or bases underlying our expectations are reasonable and make them in good faith, they almost always vary from actual results, sometimes materially. We also believe third-party statements we cite are accurate but have not independently verified them and do not warrant their accuracy or completeness. Factors (but not necessarily all the factors) that could cause results to differ include:

- commodity price changes
- debt limitations on our financial flexibility

- insufficient cash flow to fund planned investments, debt repurchases or changes to our capital plan
- inability to enter 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 our products
- joint ventures and acquisitions and our 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 “Risk Factors” in our Annual Report on Form 10-K available on our website at crc.com.

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

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Attachment 1

SUMMARY OF RESULTS

($ and shares in millions, except per share amounts)	Third Quarter 2018	Third Quarter 2017	Nine Months 2018	Nine Months 2017
Statement of Operations Data:				
Revenues and Other				
Oil and gas sales [a]	**$ 700**	$ 461	**$ 1,932**	$ 1,387
Net derivative (loss) gain from commodity contracts	**(54)**	(65)	**(259)**	51
Other revenue [a]	**182**	49	**313**	113
Total revenues and other	**828**	445	**1,986**	1,551
Costs and Other				
Production costs	**236**	222	**679**	649
General and administrative expenses	**81**	61	**234**	183
Depreciation, depletion and amortization	**128**	134	**372**	412
Taxes other than on income	**45**	39	**120**	103
Exploration expense	**4**	5	**18**	17
Other expenses, net [a]	**149**	29	**259**	76
Total costs and other	**643**	490	**1,682**	1,440
Operating Income (Loss)	**185**	(45)	**304**	111
Non-Operating (Loss) Income				
Interest and debt expense, net	**(95)**	(85)	**(281)**	(252)
Net gain on early extinguishment of debt	**2**	—	**26**	4
Gain on asset divestitures	**3**	—	**4**	21
Other non-operating expenses	**(4)**	(2)	**(16)**	(11)
Income (Loss) Before Income Taxes	**91**	(132)	**37**	(127)
Income tax	**—**	—	**—**	—
Net Income (Loss)	**91**	(132)	**37**	(127)
Net income attributable to noncontrolling interests	**(25)**	(1)	**(55)**	(1)
Net Income (Loss) Attributable to Common Stock	**$ 66**	$ (133)	**$ (18)**	$ (128)
Net income (loss) attributable to common stock per share - basic	**$ 1.34**	$ (3.11)	**$ (0.38)**	$ (3.01)
Net income (loss) attributable to common stock per share - diluted	**$ 1.32**	$ (3.11)	**$ (0.38)**	$ (3.01)
Adjusted net income (loss)	**$ 41**	$ (52)	**$ 35**	$ (173)
Adjusted net income (loss) per share - basic	**$ 0.82**	$ (1.22)	**$ 0.72**	$ (4.07)
Adjusted net income (loss) per share - diluted	**$ 0.81**	$ (1.22)	**$ 0.71**	$ (4.07)
Weighted-average common shares outstanding - basic	**48.5**	42.7	**47.0**	42.5
Weighted-average common shares outstanding - diluted	**49.1**	42.7	**47.0** [b]	42.5
Adjusted EBITDAX	**$ 308**	$ 187	**$ 803**	$ 548
Effective tax rate	**0%**	0%	**0%**	0%

(a) We adopted the new revenue recognition standard on January 1, 2018 which required certain sales-related costs to be reported as expense as opposed to being netted against revenue. The adoption of this standard does not affect net income. Results for reporting periods beginning after January 1, 2018 are presented under the new accounting standard while prior periods are not adjusted and continue to be reported under accounting standards in effect for the prior periods. Under prior accounting standards, for the three and nine months ended September 30, 2018, oil and gas sales would have been $695 million and $1,915 million, respectively, other revenue would have been $177 million and $242 million, respectively, and other expenses, net would have been $139 million and $171 million, respectively.

(b) Weighted-average common shares outstanding for adjusted net income (loss) per share - diluted were 47.6 million.

($ and shares in millions)	Third Quarter 2018	2017	Nine Months 2018	2017
Cash Flow Data:				
Net cash provided by operating activities	**$ 159**	$ 105	**$ 393**	$ 225
Net cash used in investing activities	**$ (158)**	$ (100)	**$ (965)**	$ (174)
Net cash (used) provided by financing activities	**$ (12)**	$ 14	**$ 583**	$ (35)

Balance Sheet Data:	**September 30, 2018**	December 31, 2017
Total current assets	**$ 546**	$ 483
Total property, plant and equipment, net	**$ 6,386**	$ 5,696
Total current liabilities	**$ 871**	$ 732
Long-term debt	**$ 5,108**	$ 5,306
Mezzanine equity	**$ 745**	$ —
Equity	**$ (605)**	$ (720)
Outstanding shares as of	**48.6**	42.9

STOCK-BASED COMPENSATION

Our stock price increased $38.07 or over 364% from $10.46 as of September 30, 2017 to $48.53 as of September 30, 2018. Due to our stock price increase, we recognized a significant increase in stock-based compensation expense that is included in both general and administrative expenses and production costs as shown in the following table:

($ in millions, except per BOE amounts)	Third Quarter 2018	2017	Nine Months 2018	2017
General and administrative expenses				
Cash-settled awards	**$ 11**	$ 2	**$ 33**	$ 3
Equity-settled awards	**2**	3	**10**	10
Total stock-based compensation in G&A	**$ 13**	$ 5	**$ 43**	$ 13
Total stock-based compensation in G&A per Boe	**$ 1.04**	$ 0.43	**$ 1.20**	$ 0.37
Production costs				
Cash-settled awards	**$ 2**	$ —	**$ 8**	$ —
Equity-settled awards	**1**	1	**3**	3
Total stock-based compensation in production costs	**$ 3**	$ 1	**$ 11**	$ 3
Total stock-based compensation in production costs per Boe	**$ 0.24**	$ 0.09	**$ 0.31**	$ 0.08
Total company stock-based compensation	**$ 16**	$ 6	**$ 54**	$ 16
Total company stock-based compensation per Boe	**$ 1.28**	$ 0.52	**$ 1.51**	$ 0.45

PRODUCTION STATISTICS

Net Oil, NGLs and Natural Gas Production Per Day	Third Quarter		Nine Months	
	2018	2017	**2018**	2017
Oil (MBbl/d)				
San Joaquin Basin	**54**	51	**52**	52
Los Angeles Basin	**26**	27	**25**	27
Ventura Basin	**4**	4	**4**	5
Sacramento Basin	**—**	—	**—**	—
Total	**84**	82	**81**	84
NGLs (MBbl/d)				
San Joaquin Basin	**16**	15	**16**	15
Los Angeles Basin	**—**	—	**—**	—
Ventura Basin	**1**	1	**1**	1
Sacramento Basin	**—**	—	**—**	—
Total	**17**	16	**17**	16
Natural Gas (MMcf/d)				
San Joaquin Basin	**172**	139	**162**	140
Los Angeles Basin	**1**	2	**1**	1
Ventura Basin	**6**	8	**7**	8
Sacramento Basin	**29**	33	**30**	32
Total	**208**	182	**200**	181
Total Production (MBoe/d) [(a)]	**136**	128	**131**	130

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

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

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

We define Adjusted EBITDAX as earnings before interest expense; income taxes; depreciation, depletion and amortization; exploration expense; other unusual, out-of-period and infrequent items; and other non-cash items. Core Adjusted EBITDAX removes the transitory effects of settled hedges and cash-settled stock-based compensation expense. Discretionary Cash Flow excludes certain contractual commitments and the impact of changes in working capital from the calculation of cash flow from operations. We believe these measures provide useful information in assessing our financial condition, results of operations and cash flows and 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. 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

ADJUSTED NET INCOME (LOSS)

The following table presents a reconciliation of the GAAP financial measure of net income (loss) attributable to common stock to the non-GAAP financial measure of adjusted net income (loss) and presents the GAAP financial measure of net (loss) income attributable to common stock per diluted share and the non-GAAP financial measure of adjusted net income (loss) per diluted share:

	Third Quarter		Nine Months	
($ millions, except per share amounts)	**2018**	2017	**2018**	2017
Net income (loss)	**$ 91**	$ (132)	**$ 37**	$ (127)
Net income attributable to noncontrolling interests	**(25)**	(1)	**(55)**	(1)
Net income (loss) attributable to common stock	**66**	(133)	**(18)**	(128)
Unusual, infrequent and other items:				
Non-cash derivative (gain) loss, excluding noncontrolling interest	**(28)**	72	**71**	(38)
Early retirement and severance costs	**—**	1	**4**	4
Gain on asset divestitures	**(3)**	—	**(4)**	(21)
Net gain on early extinguishment of debt	**(2)**	—	**(26)**	(4)
Other, net	**8**	8	**8**	14
Total unusual, infrequent and other items	**(25)**	81	**53**	(45)
Adjusted net income (loss)	**$ 41**	$ (52)	**$ 35**	$ (173)
Net income (loss) attributable to common stock per share - diluted	**$ 1.32**	$ (3.11)	**$ (0.38)**	$ (3.01)
Adjusted net income (loss) per share - diluted	**$ 0.81**	$ (1.22)	**$ 0.71**	$ (4.07)

DERIVATIVE GAINS AND LOSSES

	Third Quarter		Nine Months	
($ millions)	**2018**	2017	**2018**	2017
Non-cash derivative gain (loss), excluding noncontrolling interest	**$ 28**	$ (72)	**$ (71)**	$ 38
Non-cash derivative loss included in noncontrolling interest	**(3)**	(1)	**(10)**	(2)
Net (payments) proceeds on settled commodity derivatives	**(79)**	8	**(178)**	15
Net derivative (loss) gain from commodity contracts	**$ (54)**	$ (65)	**$ (259)**	$ 51

FREE CASH FLOW

($ millions)	Third Quarter 2018	Third Quarter 2017	Nine Months 2018	Nine Months 2017
Net cash provided by operating activities	**$ 159**	$ 105	**$ 393**	$ 225
Capital investment	**(177)**	(100)	**(504)**	(232)
Free cash flow	**(18)**	5	**(111)**	(7)
BSP funded capital investment	**19**	30	**37**	82
Free cash flow excluding BSP funded capital	**$ 1**	$ 35	**$ (74)**	$ 75

DISCRETIONARY CASH FLOW

($ millions)	Third Quarter 2018	Third Quarter 2017	Nine Months 2018	Nine Months 2017
Adjusted EBITDAX	**$ 308**	$ 187	**$ 803**	$ 548
Cash Interest	**(69)**	(56)	**(284)**	(251)
Distributions to noncontrolling interest holders:				
BSP joint venture	**(18)**	(5)	**(35)**	(6)
Ares joint venture	**(21)**	—	**(45)**	—
Discretionary Cash Flow	**$ 200**	$ 126	**$ 439**	$ 291

ADJUSTED EBITDAX AND CORE ADJUSTED EBITDAX

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

($ millions)	Third Quarter 2018	Third Quarter 2017	Nine Months 2018	Nine Months 2017
Net income (loss)	**$ 91**	$ (132)	**$ 37**	$ (127)
Interest and debt expense, net	**95**	85	**281**	252
Interest income	**—**	—	**(1)**	—
Depreciation, depletion and amortization	**128**	134	**372**	412
Exploration expense	**4**	5	**18**	17
Unusual, infrequent and other items [(a)]	**(25)**	81	**53**	(45)
Other non-cash items	**15**	14	**43**	39
Adjusted EBITDAX (A)	**$ 308**	$ 187	**$ 803**	$ 548
Net payments (proceeds) on settled commodity derivatives	**79**	(8)	**178**	(15)
Cash-settled stock-based compensation	**13**	2	**41**	3
Core Adjusted EBITDAX	**$ 400**	$ 181	**$ 1,022**	$ 536
Net cash provided (used) by operating activities	**$ 159**	$ 105	**$ 393**	$ 225
Cash interest	**69**	56	**284**	251
Exploration expenditures	**4**	5	**14**	16
Changes in operating assets and liabilities	**76**	13	**113**	42
Other, net	**—**	8	**(1)**	14
Adjusted EBITDAX (A)	**$ 308**	$ 187	**$ 803**	$ 548
Net payments (proceeds) on settled commodity derivatives	**79**	(8)	**178**	(15)
Cash-settled stock-based compensation	**13**	2	**41**	3
Core Adjusted EBITDAX	**$ 400**	$ 181	**$ 1,022**	$ 536

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

ADJUSTED EBITDAX MARGIN

($ millions)	Third Quarter 2018	Third Quarter 2017	Nine Months 2018	Nine Months 2017
Total revenues and other	**$ 828**	$ 445	**$ 1,986**	$ 1,551
Non-cash derivative loss (gain)	**(25)**	73	**81**	(36)
Adjusted revenues (B)	**$ 803**	$ 518	**$ 2,067**	$ 1,515
Adjusted EBITDAX Margin (A)/(B)	**38%**	36%	**39%**	36%

PRODUCTION COSTS PER BOE

($ per Boe)	Third Quarter 2018	Third Quarter 2017	Nine Months 2018	Nine Months 2017
Production costs	**$ 18.92**	$ 18.90	**$ 18.98**	$ 18.31
Costs attributable to PSC-type contracts	**(1.37)**	(1.09)	**(1.50)**	(1.10)
Production costs, excluding effects of PSC-type contracts	**$ 17.55**	$ 17.81	**$ 17.48**	$ 17.21

ADJUSTED NET LOSS VARIANCE ANALYSIS
($ millions)

2017 3rd Quarter Adjusted Net Loss	**$**	**(52)**
Price - Oil		100 [a]
Price - NGLs		15
Price - Natural Gas		9
Volume		21
Production cost		(14)
Taxes other than on income		(6)
DD&A rate		13
Interest expense		(10)
Adjusted general & administrative expenses		(20)
Net income attributable to noncontrolling interests		(24)
All others		9
2018 3rd Quarter Adjusted Net Income	**$**	**41**

2017 Nine-Month Adjusted Net Loss	**$**	**(173)**
Price - Oil		325 [a]
Price - NGLs		46
Price - Natural Gas		5
Volume		(27)
Production cost		(30)
Taxes other than on income		(17)
DD&A rate		43
Interest expense		(29)
Adjusted general & administrative expenses		(46)
Net income attributable to noncontrolling interests		(54)
All others		(8)
2018 Nine-Month Adjusted Net Income	**$**	**35**

(a) Includes cash settlement payments on commodity derivatives.

CAPITAL INVESTMENTS

($ millions)	Third Quarter **2018**	Third Quarter 2017	Nine Months **2018**	Nine Months 2017
Internally Funded Capital	**$ 158**	$ 70	**$ 467**	$ 150
BSP Funded Capital	**19**	30	**37**	82
Consolidated Reported Capital Investments	**$ 177**	$ 100	**$ 504**	$ 232
MIRA Funded Capital	**19**	30	**46**	38
Total Capital Program	**$ 196**	$ 130	**$ 550**	$ 270

PRICE STATISTICS

	Third Quarter		Nine Months	
	2018	2017	**2018**	2017
Realized Prices				
Oil with hedge ($/Bbl)	**$ 63.63**	$ 50.02	**$ 63.53**	$ 49.42
Oil without hedge ($/Bbl)	**$ 73.73**	$ 48.90	**$ 71.53**	$ 48.76
NGLs ($/Bbl)	**$ 45.72**	$ 34.63	**$ 43.71**	$ 33.00
Natural gas ($/Mcf) [(a)]	**$ 3.16**	$ 2.56	**$ 2.73**	$ 2.64
Index Prices				
Brent oil ($/Bbl)	**$ 75.97**	$ 52.18	**$ 72.68**	$ 52.59
WTI oil ($/Bbl)	**$ 69.50**	$ 48.21	**$ 66.75**	$ 49.47
NYMEX gas ($/MMBtu)	**$ 2.88**	$ 2.95	**$ 2.83**	$ 3.12
Realized Prices as Percentage of Index Prices				
Oil with hedge as a percentage of Brent	**84%**	96%	**87%**	94%
Oil without hedge as a percentage of Brent	**97%**	94%	**98%**	93%
Oil with hedge as a percentage of WTI	**92%**	104%	**95%**	100%
Oil without hedge as a percentage of WTI	**106%**	101%	**107%**	99%
NGLs as a percentage of Brent	**60%**	66%	**60%**	63%
NGLs as a percentage of WTI	**66%**	72%	**65%**	67%
Natural gas as a percentage of NYMEX [(a)]	**110%**	87%	**96%**	85%

(a) See Note (a) on Attachment 1 related to our adoption of the new accounting standard regarding the reporting of certain sales related costs. For the three months and nine months ended September 30, 2018, the realized gas price would have been $2.98 per Mcf and $2.52 per Mcf, respectively, and the realized gas price as a percentage of NYMEX would have been 103% and 89%, respectively.

THIRD QUARTER DRILLING ACTIVITY

Wells Drilled (Gross)	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Development Wells					
Primary	17	—	—	—	17
Waterflood	9	16	—	—	25
Steamflood	43	—	—	—	43
Unconventional	9	—	—	—	9
Total	78	16	—	—	94
Exploration Wells					
Primary	1	—	—	—	1
Waterflood	—	—	—	—	—
Steamflood	—	—	—	—	—
Unconventional	—	—	—	—	—
Total	1	—	—	—	1
Total Wells [(a)]	79	16	—	—	95
CRC Wells Drilled	47	12	—	—	59
BSP Wells Drilled	3	4	—	—	7
MIRA Wells Drilled	29	—	—	—	29

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

HEDGES - CURRENT

	4Q 2018	1Q 2019	2Q 2019	3Q 2019	4Q 2019	Q1 2020
Crude Oil						
Sold Calls:						
Barrels per day	15,000	15,000	5,000	—	—	—
Weighted-average Brent price per barrel	$58.83	$66.15	$68.45	$—	$—	$—
Purchased Calls:						
Barrels per day	—	2,000	—	—	—	—
Weighted-average Brent price per barrel	$—	$71.00	$—	$—	$—	$—
Purchased Puts:						
Barrels per day	—	38,000	40,000	40,000	35,000	10,000
Weighted-average Brent price per barrel	$—	$65.66	$69.75	$73.13	$75.71	$75.00
Sold Puts:						
Barrels per day	19,000	40,000	35,000	40,000	35,000	10,000
Weighted-average Brent price per barrel	$45.00	$51.88	$55.71	$57.50	$60.00	$60.00
Swaps:						
Barrels per day	48,000	7,000 (1)	—	—	—	—
Weighted-average Brent price per barrel	$60.35	$67.71	$—	$—	$—	$—

(1) Certain of our counterparties have options to increase swap volumes by up to 5,000 barrels per day at a weighted-average Brent price of $70.00 for the first quarter of 2019.

The BSP JV entered into crude oil derivatives that are included in our consolidated results but not in the above table. The hedges entered into by the BSP JV could affect the timing of the redemption of the JV interest. The BSP JV sold calls for up to approximately 1,000 barrels per day at a weighted-average price per barrel of $60.00 per barrel for 2018 through 2020. The BSP JV purchased puts for up to approximately 2,000 barrels per day at a weighted-average price per barrel of approximately $50.00 for 2018 through 2021. The BSP JV also entered into natural gas swaps for insignificant volumes for periods through May 2021.

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 4, 2021.

2018 FOURTH QUARTER GUIDANCE

Anticipated Realizations Against the Prevailing Index Prices for Q4 2018 [(a)]

Oil	93% to 98% of Brent
NGLs	55% to 60% of Brent
Natural Gas	100% to 110% of NYMEX

2018 Fourth Quarter Production, Capital and Income Statement Guidance

Production [(b) & (c)]	136 to 139 MBOE per day
Capital	$170 million to $200 million
Production costs [(b) & (c)]	$17.75 to $19.25 per BOE
Adjusted general and administrative expenses [(b) & (d)]	$6.30 to $6.70 per BOE
Depreciation, depletion and amortization [(b)]	$10.10 to $10.40 per BOE
Taxes other than on income	$41 million to $45 million
Exploration expense	$10 million to $15 million
Interest expense [(e)]	$96 million to $100 million
Cash interest [(e)]	$150 million to $155 million
Income tax expense rate	0%
Cash tax rate	0%

Pre-tax 2018 Fourth Quarter Price Sensitivities [(f)]

$1 change in Brent index - Oil [(g)]	$1.2 million
$1 change in Brent index - NGLs	$1.0 million
$0.50 change in NYMEX - Gas	$4.9 million

(a) Realizations exclude hedge effects.

(b) Based on an average assumed Q4 2018 Brent price of $75 per barrel.

(c) Based on an average assumed Brent price of $70 per barrel, Q4 2018 production would be 137 to 140 MBOE per day and production costs would be $17.65 to $19.15 per BOE. Based on an average assumed Brent price of $80 per barrel, Q4 2018 production would be 135 to 138 MBOE per day and production costs would be $17.85 to $19.35 per BOE.

(d) Our long-term incentive compensation programs for non-executive employees are stock based but payable in cash. Accounting rules require that we adjust the cumulative liability for all vested but unpaid awards under these programs to the amount that would be paid using our stock price as of the end of each quarter. Therefore, in addition to the normal pro-rata vesting expense associated with these programs, our quarterly G&A expense could include this cumulative adjustment depending on movement in our stock price. Our stock price at September 30, 2018 was $48.53 per share, which was used for fourth quarter guidance. Only about 1/3 of such cumulative adjustment would result in a cash liability in the same year as the adjustment because of the pro-rata three-year vesting of our incentive compensation programs.

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