NEWS RELEASE

For immediate release

California Resources Corporation Announces Fourth Quarter 2017 and Year End Results

LOS ANGELES, February 26, 2018 – California Resources Corporation (NYSE:CRC) (the Company), an independent California-based oil and gas exploration and production company, today reported a net loss attributable to common stock (CRC net loss) of $138 million, or $3.23 per diluted share, for the fourth quarter of 2017. The adjusted net loss[1] for the fourth quarter of 2017 was $14 million, or $0.33 per diluted share. For the full year of 2017, the CRC net loss was $266 million, or $6.26 per diluted share. The adjusted net loss[1] for the full year of 2017 was $187 million, or $4.40 per diluted share.

Adjusted EBITDAX[1] for the fourth quarter of 2017 was $222 million and $761 million for the full year of 2017. Cash provided by operating activities was $23 million for the fourth quarter of 2017 and $248 million for the full year of 2017. Capital investments for the fourth quarter of 2017 were $139 million and $371 million for the full year of 2017, of which $14 million was funded by CRC's joint venture (JV) partner Benefit Street Partners (BSP) in the fourth quarter and $96 million for the full year. For the full year of 2017, CRC was free cash flow[1] neutral after working capital and excluding capital that was funded by BSP.

Quarterly Highlights Include:

- Produced126,000 BOE per day
- Invested capital of $139 million, of which JV partner BSP funded $14 million
- Drilled 37 wells with internally funded capital and 44 wells with BSP and Macquarie Infrastructure and Real Assets (MIRA) capital
- Generated adjusted EBITDAX[1] of $222 million, reflecting an adjusted EBITDAX margin[1] of 39%

Full Year Highlights Include:

- Proved reserves of 618 MMBOE, organically replacing 119% of reserves from the capital program, excluding price revisions
- Organic F&D costs of $6.82 per BOE, excluding price revisions
- Invested capital of $371 million, of which JV partner BSP funded $96 million
- Drilled 110 wells with internally funded capital and 119 wells with BSP and MIRA funded capital
- Generated adjusted EBITDAX[1] of $761 million, reflecting an adjusted EBITDAX margin[1] of 36%

[1] See Attachment 2 for explanations of how CRC calculates and uses the non–GAAP measures of adjusted EBITDAX, adjusted EBITDAX margin, PV-10, adjusted general and administrative expenses, free cash flow, production costs (excluding the effects of production sharing-type contracts (PSC)) and adjusted net loss, and for reconciliations of the foregoing to their nearest GAAP measure as applicable. VCI is calculated by dividing the net present value of the project's expected pre-tax cash flow over its life by the net present value of the related investments, each using a 10 percent discount rate.

Todd Stevens, CRC's President and Chief Executive Officer, said, "In 2017, we followed a strategic plan to focus on projects that offered the best value creation, to live within cash flow and to emphasize disciplined growth, and I am pleased to report that we delivered on all fronts. We replaced 119% of our production, despite a limited capital program. We leveraged our portfolio flexibility through JV partnerships to accelerate and de-risk our actionable inventory. As we have done every year since our inception, we continued to live within our cash flow, investing approximately $240 million of CRC development capital in 2017 with a VCI[1] of 1.7 or fully-burdened returns of 30%. In addition, we took steps to meaningfully strengthen our financial position with a new credit amendment that provides a clear runway and a path to further de-lever. In 2018, we expect to build upon this solid momentum as we extend our track record of disciplined execution into a mid-cycle commodity environment and capture the significant upside that lies ahead. By remaining dedicated to our strategy centered on optimizing CRC's world-class resources, driving operational execution and strengthening our balance sheet, we expect to deliver meaningful value creation for our shareholders in 2018 and beyond."

Fourth Quarter 2017 Results

For the fourth quarter of 2017, the CRC net loss was $138 million, or $3.23 per diluted share, and the adjusted net loss[1] was $14 million or $0.33 per diluted share. The adjusted net loss[1] excluded $116 million of non-cash derivatives losses and a net $8 million charge for other unusual and infrequent items.

Total daily production volumes averaged 126,000 barrels of oil equivalent (BOE) per day for the fourth quarter of 2017. Oil volumes averaged 80,000 barrels per day, NGL volumes averaged 16,000 barrels per day and gas volumes averaged 179,000 thousand cubic feet (MCF) per day. These results reflect approximately 1,300 BOE per day of negative PSC effects due to higher realized prices in the fourth quarter compared to expected prices, as well as a 700 BOE per day quarterly impact due to the California wildfires that occurred in December 2017.

Realized crude oil prices, including the effect of settled hedges, increased by $11.44 per barrel to $56.92 per barrel from the prior year comparable period. Settled hedges decreased realized crude oil prices by $2.95 per barrel. Average realized NGL prices registered $44.03 per barrel and realized natural gas prices were $2.77 per MCF.

Production costs for the fourth quarter of 2017 were $227 million, or $19.64 per BOE, compared to $17.50 per BOE in the prior year comparable period. The industry practice for reporting PSCs can result in higher production costs per barrel as gross field operating costs are matched with net production. Excluding the PSC effects, per unit production costs[1] for the fourth quarter of 2017 would have been $18.31. The increase in unit based production costs was driven by an increase in energy costs, a ramp-up of downhole maintenance activity in line with stronger commodity prices and lower production volumes, but was partially offset by a more efficient use of energy. General and administrative (G&A) expenses were $68 million for the fourth quarter of 2017. Adjusted general and administrative expenses[1] for the fourth quarter of 2017 were $67 million compared to $61 million in the prior year comparable period. The increase in adjusted G&A expenses[1] was a result of the timing of grants coupled with the higher costs of performance-based bonus and incentive compensation plans due to better than expected results.

CRC reported taxes other than on income of $33 million and exploration expense of $5 million for the fourth quarter of 2017.

Capital investment in the fourth quarter of 2017 totaled $139 million, consisting of $125 million of internally funded capital and $14 million of BSP funded capital. Approximately $95 million was directed to drilling and capital workovers.

Cash provided by operating activities was $23 million.

<u>Full Year 2017 Results</u>

For the full year of 2017, the CRC net loss was $266 million, or $6.26 per diluted share. The adjusted net loss[1] was $187 million, or $4.40 per diluted share, which excluded $78 million of non-cash derivative losses, $21 million of gains from asset divestitures, $4 million of net gains on early retirement of debt and a $26 million net charge from other unusual and infrequent items.

Total daily production volumes averaged 129,000 BOE per day for the full year of 2017. Oil volumes averaged 83,000 barrels per day, NGL volumes averaged 16,000 barrels per day, and gas volumes averaged 182,000 MCF per day.

Realized crude oil prices, including the effect of settled hedges, increased $9.23 per barrel to $51.24 per barrel from $42.01 per barrel in 2016. Settled hedges decreased 2017 realized crude oil prices by $0.23 per barrel compared with a $2.29 per barrel increase in 2016. Realized NGL prices increased 60% to $35.76 from $22.39 per barrel in 2016. Realized natural gas prices increased 17% to $2.67 per MCF compared with $2.28 per MCF in 2016.

Production costs for the full year of 2017 were $876 million, or $18.64 per BOE. Per unit production costs, excluding the effect of PSCs[1], were $17.48 per BOE. The increase in production costs of $76 million from the prior year was driven by an increase in energy costs and a ramp-up of downhole and surface maintenance activity in line with stronger commodity prices, but were partially offset by a more efficient use of energy. While higher natural gas prices increase CRC's production costs for power and steam generation, they result in a net benefit due to higher revenue generated from natural gas sales. G&A expenses were $259 million for the full year of 2017. Adjusted G&A expenses[1] for the full year of 2017 were $254 million compared to $228 million in 2016. The increase in adjusted G&A expenses[1] was a result of the timing of grants coupled with the higher costs of performance-based bonus and incentive compensation plans due to better than expected results.

CRC reported taxes other than on income of $136 million and exploration expense of $22 million for the full year of 2017.

Capital investment in 2017 totaled $371 million, consisting of $275 million of CRC internally funded capital and $96 million of BSP funded capital. Approximately $266 million was directed to drilling and capital workovers. The Company's MIRA joint venture funded an additional $58 million of investment.

Cash provided by operating activities for the full year of 2017 was $248 million. The Company was free cash flow[1] neutral after working capital and excluding capital that was funded by BSP.

Operational Update

CRC operated an average of nine rigs during the fourth quarter of 2017 and drilled 81 wells, including those drilled with BSP and MIRA capital, which consisted of 75 development wells (36 steamflood, 25 waterflood, 13 primary and one unconventional) and six exploration wells (five steamflood and one primary). Most of the drilling activity was directed toward steamfloods and waterfloods, which have different production profiles and longer response times than typical conventional wells. As a result, the full production contribution is not typically experienced in the same year that the well is drilled. In the San Joaquin basin, CRC operated seven rigs and produced approximately 88 MBOE per day for the fourth quarter. The Los Angeles basin had one rig directed toward waterflood projects, and contributed 26 MBOE per day of production in the fourth quarter of 2017. The impact of the production sharing agreements in Long Beach decreased production by 1,300 BOE per day in the fourth quarter due to fewer cost-recovery barrels as a result of higher oil prices than initially expected. The Ventura basin activity included one rig focused on conventional projects and produced approximately 6,000 BOE per day for the fourth quarter. The California wildfires negatively impacted production by approximately 2,200 BOE per day in December 2017 and production remained affected by approximately 1,200 BOE per day in January 2018 due to third party power and access issues related to the fires and subsequent mudslides. First quarter of 2018 production guidance reflects a 400 BOE per day reduction primarily due to these issues, a 600 BOE per day impact for PSC effects, as well as other factors. CRC had no development drilling activity in the Sacramento basin and continues to focus on oil weighted projects.

Balance Sheet Strengthening Update

During February 2018, CRC entered into a midstream joint venture with an affiliate of Ares Management, L.P. For more details on the transaction, please see CRC's press release and Form 8-K dated February 7, 2018.

Year-End 2017 Reserves and PV-10 Value[1]

CRC's proved reserves totaled 618 MMBOE as of the end of 2017, up from 568 MMBOE at year-end 2016. Excluding positive price revisions, the Company organically replaced 119% of proved reserves. This strong reserve replacement ratio (RRR)** was achieved with a limited, well executed capital program for the year, in addition to positive performance revisions primarily in Huntington Beach and Buena Vista Area. A total of approximately 34 MMBOE of additions were related to extensions and discoveries in several CRC fields and another 22 MMBOE was added through positive performance revisions. All-in 2017 Finding and Development (F&D) costs were $3.94 per BOE in 2017, including price revisions. Organic F&D costs were $6.82 per BOE in 2017, which exclude price revisions.

Summary of Changes in Proved Reserves Based on the SEC Price Deck* (Million BOE)

Balance at December 31, 2016	568
Revisions Related to Performance	22
Extensions and Discoveries	34
Sales	(8)
Revisions Related to Price	49
Production	(47)
Balance at December 31, 2017	618

2017 Organic Finding and Development Cost**	$	6.82

*Calculated using the first-day-of-the-month twelve-month average Brent oil price of $54.42 per barrel and NYMEX natural gas price of $2.98 per Million British Thermal Units (MMBTU), before adjustments for gravity, quality and transportation costs, in accordance with Securities and Exchange Commission (SEC) rules and regulations.
** See calculation of RRR and F&D on Attachment 3.

The present value of CRC's proved reserves as of December 31, 2017 was approximately $4.5 billion on a pre-tax basis, discounted at 10% (PV-10[1]).

2018 Capital Budget

With stronger expected cash flows, CRC estimates its 2018 capital program will range from $425 million to $450 million, which includes approximately $100 to $150 million in JV capital. CRC's 2018 capital program may grow further through the use of cash on the balance sheet, additional tranches from existing JVs as well as potential new JVs. CRC’s direct investment level will be largely directed to waterflood and steamflood investments which will drive enhanced production into 2019.

Credit Facility Amendment

CRC entered into its seventh amendment of the 2014 Credit Facility in November 2017. This amendment received unanimous approval from all 29 lenders and financial institutions and became effective after the closing of a new $1.3 billion first lien secured term loan facility (“2017 Term Loan”). Net proceeds were used to pay the $559 million remaining balance of the 2014 Term Loan, reduce the balance of the 2014 Revolving Credit Facility and pay accrued interest. The amendment extended the maturity date of the 2014 Revolving Credit Facility to June 30, 2021 and modified some of its covenants. Subsequent to the amendment, CRC was able to eliminate the springing maturity features related to the 5% notes due January 15, 2020 and the 5 ½% notes due September 15, 2021 by buying back $65 million of principal of the 5% Notes and $35 million in principal of the 5 ½% Notes. For more details on the amendment, please see the Company's Form 8-K disclosure dated November 17, 2017.

Conference Call Details

To participate in today's conference call scheduled for 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/10115435. A digital replay of the conference call will be archived for approximately 30 days and supplemental slides for the conference call will be available online in the Investor Relations section of www.crc.com.

About California Resources Corporation

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

Forward-Looking Statements

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

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

Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. While CRC believes the assumptions or bases underlying our expectations are reasonable and make them in good faith, they almost always vary from actual results, sometimes materially. Factors (but not necessarily all the factors) that could cause results to differ include:

- commodity price changes
- debt limitations on its financial flexibility
- insufficient cash flow to fund planned investment
- inability to enter desirable transactions including asset sales and joint ventures
- legislative or regulatory changes, including those related to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy,

water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products
- unexpected geologic conditions
- changes in business strategy
- inability to replace reserves
- insufficient capital, including as a result of lender restrictions, unavailability of capital markets or inability to attract potential investors
- inability to enter efficient hedges
- equipment, service or labor price inflation or unavailability
- availability or timing of, or conditions imposed on, permits and approvals
- lower-than-expected production, reserves or resources from development projects or acquisitions or higher-than-expected decline rates
- disruptions due to accidents, mechanical failures, transportation or storage constraints, natural disasters, labor difficulties, cyber attacks or other catastrophic events
- factors discussed in "Risk Factors" in CRC's Annual Report on Form 10-K available on its website at www.crc.com.

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

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Attachment 1

SUMMARY OF RESULTS

($ and shares in millions, except per share amounts)	Fourth Quarter **2017**	Fourth Quarter 2016	Twelve Months **2017**	Twelve Months 2016
Statement of Operations Data:				
Revenues and Other				
Oil and gas net sales	**$ 549**	$ 464	**$ 1,936**	$ 1,621
Net derivative losses	**(141)**	(49)	**(90)**	(206)
Other revenue	**47**	37	**160**	132
Total revenues and other	**455**	452	**2,006**	1,547
Costs and Other				
Production costs	**227**	217	**876**	800
General and administrative expenses	**68**	62	**259**	248
Depreciation, depletion and amortization	**132**	137	**544**	559
Taxes other than on income	**33**	26	**136**	144
Exploration expense	**5**	10	**22**	23
Other expenses, net	**30**	3	**106**	79
Total costs and other	**495**	455	**1,943**	1,853
Operating (Loss) Income	**(40)**	(3)	**63**	(306)
Non-Operating (Loss) Income				
Interest and debt expense, net	**(91)**	(85)	**(343)**	(328)
Net gains on early extinguishment of debt	**—**	12	**4**	805
(Losses) gains on asset divestitures	**—**	(1)	**21**	30
Other non-operating expense	**(4)**	—	**(7)**	—
(Loss) Income Before Income Taxes	**(135)**	(77)	**(262)**	201
Income tax benefit	**—**	—	**—**	78
Net (Loss) Income	**(135)**	(77)	**(262)**	279
Net income attributable to noncontrolling interest	**(3)**	—	**(4)**	—
Net (Loss) Income Attributable to Common Stock	**$ (138)**	$ (77)	**$ (266)**	$ 279
Net (loss) income attributable to common stock per share - basic and diluted	**$ (3.23)**	$ (1.83)	**$ (6.26)**	$ 6.76
Adjusted net loss	**$ (14)**	$ (74)	**$ (187)**	$ (317)
Adjusted net loss per diluted share	**$ (0.33)**	$ (1.76)	**$ (4.40)**	$ (7.85)
Weighted-average common shares outstanding - diluted	**42.7**	42.1	**42.5**	40.4
Adjusted EBITDAX	**$ 222**	$ 168	**$ 761**	$ 616
Effective tax rate	**0%**	0%	**0%**	(39)%
Cash Flow Data:				
Net cash provided (used) by operating activities	**$ 23**	$ (15)	**$ 248**	$ 130
Net cash used in investing activities	**$ (139)**	$ (30)	**$ (313)**	$ (61)
Net cash provided (used) by financing activities	**$ 108**	$ 47	**$ 73**	$ (69)

Balance Sheet Data:	**December 31, 2017**	December 31, 2016
Total current assets	**$ 483**	$ 425
Total property, plant and equipment, net	**$ 5,696**	$ 5,885
Current maturities of long-term debt	**$ —**	$ 100
Other current liabilities	**$ 732**	$ 626
Long-term debt, principal amount	**$ 5,306**	$ 5,168
Total equity	**$ (720)**	$ (557)
Outstanding shares as of	**42.9**	42.5

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 nature, timing, amount and frequency. Therefore, management uses measures called adjusted net income (loss) and adjusted general and administrative expenses, both which exclude those items. These measures are not meant to disassociate items from management's performance, but rather are 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) and adjusted general and administrative expenses are not considered to be alternatives to net income (loss) or general and administrative expenses, respectively, reported in accordance with U.S. generally accepted accounting principles (GAAP).

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

ADJUSTED NET 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 loss:

	Fourth Quarter		Twelve Months	
($ millions, except per share amounts)	**2017**	2016	**2017**	2016
Net (loss) income attributable to common stock	**$ (138)**	$ (77)	**$ (266)**	$ 279
Unusual and infrequent items:				
Non-cash derivative losses (gains), excluding noncontrolling interest	**116**	40	**78**	283
Early retirement, severance and other costs	**1**	1	**5**	20
Losses (gains) on asset divestitures	**—**	1	**(21)**	(30)
Net gains on early extinguishment of debt	**—**	(12)	**(4)**	(805)
Other	**7**	(27)	**21**	(13)
Total unusual and infrequent items	**124**	3	**79**	(545)
Deferred debt issuance costs write-off	**—**	—	**—**	12
Reversal of valuation allowance for deferred tax assets [a]	**—**	—	**—**	(63)
Adjusted net loss	**$ (14)**	$ (74)	**$ (187)**	$ (317)
Net (loss) income attributable to common stock per diluted share	**$ (3.23)**	$ (1.83)	**$ (6.26)**	$ 6.76
Adjusted net loss per diluted share	**$ (0.33)**	$ (1.76)	**$ (4.40)**	$ (7.85)

(a) Amount represents the out-of-period portion of the valuation allowance reversal.

DERIVATIVES GAINS AND LOSSES

	Fourth Quarter		Twelve Months	
($ millions)	**2017**	2016	**2017**	2016
Non-cash derivative losses, excluding noncontrolling interest	**$ (116)**	$ (40)	**$ (78)**	$ (283)
Non-cash derivative losses for noncontrolling interest	**(3)**	—	**(5)**	—
Cash (payments) proceeds from settled derivatives	**(22)**	(9)	**(7)**	77
Net derivative losses	**$ (141)**	$ (49)	**$ (90)**	$ (206)

FREE CASH FLOW

($ millions)	Fourth Quarter 2017	Fourth Quarter 2016	Twelve Months 2017	Twelve Months 2016
Net cash provided (used) by operating activities	**$ 23**	$ (15)	**$ 248**	$ 130
Capital investment	**(139)**	(31)	**(371)**	(75)
Changes in capital accruals	**1**	(1)	**27**	(6)
Free cash flow, after working capital	**(115)**	(47)	**(96)**	49
BSP funded capital investment	**14**	—	**96**	—
Free cash flow, excluding BSP funded capital	**$ (101)**	$ (47)	**$ —**	$ 49

ADJUSTED GENERAL AND ADMINISTRATIVE EXPENSES

($ millions)	Fourth Quarter 2017	Fourth Quarter 2016	Twelve Months 2017	Twelve Months 2016
General and administrative expenses	**$ 68**	$ 62	**$ 259**	$ 248
Early retirement and severance costs	**(1)**	(1)	**(5)**	(20)
Adjusted general and administrative expenses	**$ 67**	$ 61	**$ 254**	$ 228

ADJUSTED EBITDAX

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

($ millions)	Fourth Quarter 2017	Fourth Quarter 2016	Twelve Months 2017	Twelve Months 2016
Net (loss) income attributable to common stock	**$ (138)**	$ (77)	**$ (266)**	$ 279
Interest and debt expense, net	**91**	85	**343**	328
Income tax benefit	**—**	—	**—**	(78)
Depreciation, depletion and amortization, excluding noncontrolling interest	**129**	137	**535**	559
Exploration expense	**5**	10	**22**	23
Unusual and infrequent items [c]	**124**	3	**79**	(545)
Other non-cash items	**11**	10	**48**	50
Adjusted EBITDAX (A)	**$ 222**	$ 168	**$ 761**	$ 616
Net cash provided (used) by operating activities	**$ 23**	$ (15)	**$ 248**	$ 130
Cash interest	**145**	140	**396**	384
Exploration expenditures	**4**	7	**20**	20
Changes in operating assets and liabilities	**43**	63	**76**	95
Other, net	**7**	(27)	**21**	(13)
Adjusted EBITDAX (A)	**$ 222**	$ 168	**$ 761**	$ 616

(c) See Adjusted Net Loss reconciliation.

ADJUSTED EBITDAX MARGIN

($ millions)	Fourth Quarter 2017	Fourth Quarter 2016	Twelve Months 2017	Twelve Months 2016
Total Revenues	**$ 455**	$ 452	**$ 2,006**	$ 1,547
Non-cash derivative losses	**119**	40	**83**	283
Adjusted revenues (B)	**$ 574**	**$ 492**	**$ 2,089**	**$ 1,830**
Adjusted EBITDAX Margin (A)/(B)	**39%**	**34%**	**36%**	**34%**

PRODUCTION COSTS PER BOE

($ per Boe)	Fourth Quarter 2017	Fourth Quarter 2016	Twelve Months 2017	Twelve Months 2016
Production Costs	**$ 19.64**	$ 17.50	**$ 18.64**	$ 15.61
Costs attributable to PSC type contracts	**(1.33)**	(1.21)	**(1.16)**	(0.92)
Production Costs, excluding the effects of PSC type contracts	**$ 18.31**	$ 16.29	**$ 17.48**	$ 14.69

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 to the non-GAAP financial measure of PV-10:

($ millions)	**2017**
Standardized measure of discounted future net cash flows	**$ 3,765**
Present value of future income taxes discounted at 10%	**780**
PV-10 of proved reserves (1)	**$ 4,545**

(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. Standard 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.

Organic Reserve Replacement Ratio [1]	**2017**
Organic proved reserves added - MMBOE	
Extensions and discoveries	**34**
Revisions related to performance	**22**
Total (A)	**56**
Production in 2017 - MMBOE (B)	**47**
Organic reserve replacement ratio (A)/(B)	**119%**

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

Finding and Development Costs[2]		**2017**	
Costs incurred - in millions (A)	**$**	**382**	
Organic proved reserves added - MMBOE (B)		**56**	
Organic finding and development costs - $/BOE (A)/(B)	**$**	**6.82**	(3)
Proved reserves added including price related revisions, net - MMBOE (C)		**97**	
All in finding and development costs - $/BOE (A)/(C)	**$**	**3.94**	(4)

(2) 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 2017 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 2017 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.

(3) We calculate organic finding and development costs by dividing the costs incurred for the year from the capital program (including development, exploration costs and asset retirement obligations) by the amount of oil-equivalent proved reserves added in the same year from extensions and discoveries and performance-related revisions.

(4) We calculate all-in finding and development costs by dividing the costs incurred for the year from the capital program (including development, exploration costs and asset retirement obligations) by the amount of oil-equivalent proved reserves added in the same year from extensions and discoveries, performance-related revisions and price-related revisions less the amount of oil-equivalent proved reserves sold in the same year.

ADJUSTED NET INCOME / (LOSS) VARIANCE ANALYSIS

($ millions)

2016 4th Quarter Adjusted Net Loss	**$**	**(74)**
Price - Oil		93
Price - NGLs		21
Price - Natural Gas		—
Volume		(31)
Production cost		(10)
DD&A		(3)
Exploration expense		5
Interest expense		(6)
Adjusted general & administrative expenses		(6)
All others		(3)
2017 4th Quarter Adjusted Net Loss	**$**	**(14)**

2016 Twelve-Month Adjusted Net Loss	**$**	**(317)**
Price - Oil		308
Price - NGLs		78
Price - Natural Gas		29
Volume		(136)
Production cost		(76)
DD&A		(30)
Exploration expense		1
Interest expense		(27)
Adjusted general & administrative expenses		(26)
Income tax		(15)
All others		24
2017 Twelve-Month Adjusted Net Loss	**$**	**(187)**

CAPITAL INVESTMENTS

($ millions)	Fourth Quarter **2017**	Fourth Quarter 2016	Twelve Months **2017**	Twelve Months 2016
Internally Funded Capital Investments	**$ 125**	$ 31	**$ 275**	$ 75
BSP Funded Capital	**14**	—	**96**	—
Consolidated Reported Capital	**$ 139**	$ 31	**$ 371**	$ 75
MIRA Funded Capital	**20**	—	**58**	—
Total Capital Program	**$ 159**	$ 31	**$ 429**	$ 75

PRODUCTION STATISTICS

Net Oil, NGLs and Natural Gas Production Per Day	Fourth Quarter 2017	Fourth Quarter 2016	Twelve Months 2017	Twelve Months 2016
Oil (MBbl/d)				
San Joaquin Basin	**50**	55	**52**	57
Los Angeles Basin	**26**	27	**27**	29
Ventura Basin	**4**	5	**4**	5
Sacramento Basin	**—**	—	**—**	—
Total	**80**	87	**83**	91
NGLs (MBbl/d)				
San Joaquin Basin	**15**	14	**15**	15
Los Angeles Basin	**—**	—	**—**	—
Ventura Basin	**1**	1	**1**	1
Sacramento Basin	**—**	—	**—**	—
Total	**16**	15	**16**	16
Natural Gas (MMcf/d)				
San Joaquin Basin	**138**	152	**140**	150
Los Angeles Basin	**1**	1	**1**	3
Ventura Basin	**7**	8	**8**	8
Sacramento Basin	**33**	34	**33**	36
Total	**179**	195	**182**	197
Total Production (MBoe/d) [(a)]	**126**	135	**129**	140

(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.

PRICE STATISTICS

	Fourth Quarter		Twelve Months	
	2017	2016	**2017**	2016
Realized Prices				
Oil with hedge ($/Bbl)	**$ 56.92**	$ 45.48	**$ 51.24**	$ 42.01
Oil without hedge ($/Bbl)	**$ 59.87**	$ 46.60	**$ 51.47**	$ 39.72
NGLs ($/Bbl)	**$ 44.03**	$ 28.99	**$ 35.76**	$ 22.39
Natural gas ($/Mcf)	**$ 2.77**	$ 2.79	**$ 2.67**	$ 2.28
Index Prices				
Brent oil ($/Bbl)	**$ 61.54**	$ 51.13	**$ 54.82**	$ 45.04
WTI oil ($/Bbl)	**$ 55.40**	$ 49.29	**$ 50.95**	$ 43.32
NYMEX gas ($/MMBtu)	**$ 3.00**	$ 2.95	**$ 3.09**	$ 2.42
Realized Prices as Percentage of Index Prices				
Oil with hedge as a percentage of Brent	**92%**	89%	**93%**	93%
Oil without hedge as a percentage of Brent	**97%**	91%	**94%**	88%
Oil with hedge as a percentage of WTI	**103%**	92%	**101%**	97%
Oil without hedge as a percentage of WTI	**108%**	95%	**101%**	92%
NGLs as a percentage of Brent	**72%**	57%	**65%**	50%
NGLs as a percentage of WTI	**79%**	59%	**70%**	52%
Natural gas as a percentage of NYMEX	**92%**	95%	**86%**	94%

FOURTH QUARTER DRILLING ACTIVITY

Wells Drilled (Gross)	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Development Wells					
Primary	11	—	2	—	13
Waterflood	20	5	—	—	25
Steamflood	36	—	—	—	36
Unconventional	1	—	—	—	1
Total	68	5	2	—	75
Exploration Wells					
Primary	—	—	—	1	1
Waterflood	—	—	—	—	—
Steamflood	5	—	—	—	5
Unconventional	—	—	—	—	—
Total	5	—	—	1	6
Total Wells	73	5	2	1	81
CRC Wells Drilled [a]	29	5	2	1	37
BSP Wells Drilled [a]	20	—	—	—	20
MIRA Wells Drilled	24	—	—	—	24

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

FULL YEAR DRILLING ACTIVITY

Wells Drilled (Gross)	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Development Wells					
Primary	28	—	2	—	30
Waterflood	50	16	—	—	66
Steamflood	115	—	—	—	115
Unconventional	12	—	—	—	12
Total	205	16	2	—	223
Exploration Wells					
Primary	—	—	—	1	1
Waterflood	—	—	—	—	—
Steamflood	5	—	—	—	5
Unconventional	—	—	—	—	—
Total	5	—	—	1	6
Total Wells	210	16	2	1	229
CRC Wells Drilled [(a)]	91	16	2	1	110
BSP Wells Drilled [(a)]	45	—	—	—	45
MIRA Wells Drilled	74	—	—	—	74

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

HEDGES - CURRENT

	1Q 2018	2Q 2018	3Q 2018	4Q 2018	1Q 2019	2Q - 4Q 2019	FY 2020
Crude Oil							
Sold Calls:							
Barrels per day	9,000	6,200	16,100	16,100	1,100	1,000	500
Weighted-average Brent price per barrel	$59.58	$60.24	$58.91	$58.91	$60.00	$60.00	$60.00
Purchased Calls:							
Barrels per day	—	—	—	—	2,000	—	—
Weighted-average Brent price per barrel	$—	$—	$—	$—	$71.00	$—	$—
Purchased Puts:							
Barrels per day	1,200	1,200	6,100	1,100	14,100	1,000	500
Weighted-average Brent price per barrel	$45.82	$45.83	$61.48	$45.85	$58.93	$45.85	$43.91
Sold Puts:							
Barrels per day	29,000	29,000	24,000	19,000	10,000	—	—
Weighted-average Brent price per barrel	$45.00	$45.00	$46.04	$45.00	$47.50	$—	$—
Swaps:							
Barrels per day	38,300	34,000	19,000	19,000	7,000	—	—
Weighted-average Brent price per barrel	$60.03	$60.00	$60.13	$60.13	$67.71	$—	$—

A small portion of the derivatives in the table above were entered into by the BSP JV, including some of the 2019 and all of the 2020 positions. The BSP JV also entered into natural gas swaps for insignificant volumes for the period of February 2018 to July 2020.

Certain of our counterparties have options to increase swap volumes by up to:

- 19,000 barrels per day at a weighted-average Brent price of $60.00 for the second quarter of 2018;
- 29,000 barrels per day at a weighted-average Brent price of $60.50 for the second half of 2018 and
- 5,000 barrels per day at a weighted-average Brent price of $70.00 for the first quarter of 2019.

RESERVES

As of December 31, 2017	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Oil Reserves (in millions of barrels)					
Proved Developed Reserves	176	104	24	—	304
Proved Undeveloped Reserves	89	39	10	—	138
Total	265	143	34	—	442
NGLs Reserves (in millions of barrels)					
Proved Developed Reserves	43	—	2	—	45
Proved Undeveloped Reserves	13	—	—	—	13
Total	56	—	2	—	58
Natural Gas Reserves (in billions of cubic feet)					
Proved Developed Reserves	447	6	20	70	543
Proved Undeveloped Reserves	138	4	6	15	163
Total	585	10	26	85	706
Total Reserves (in millions of barrels of oil equivalent)*					
Proved Developed Reserves	294	105	29	12	440
Proved Undeveloped Reserves	125	40	11	2	178
Total	419	145	40	14	618

*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.

2018 FIRST QUARTER GUIDANCE

Anticipated Realizations Against the Prevailing Index Prices for Q1 2018 [(a)]

Oil	92% to 96% of Brent
NGLs	62% to 66% of Brent
Natural Gas	88% to 92% of NYMEX

2018 First Quarter Production, Capital and Income Statement Guidance

Production	120 to 125 MBOE per day
Capital	$115 million to $135 million
Production costs	$19.25 to $20.75 per BOE
Adjusted general and administrative expenses	$6.05 to $6.35 per BOE
Depreciation, depletion and amortization	$10.50 to $10.80 per BOE
Taxes other than on income	$36 million to $40 million
Exploration expense	$6 million to $10 million
Interest expense [(b)]	$89 million to $93 million
Cash Interest [(b)]	$58 million to $62 million
Income tax expense rate	0%
Cash tax rate	0%

Pre-tax 2018 First Quarter Price Sensitivities [(c)]

$1 change in Brent index - Oil [(d)]	$1.7 million
$1 change in Brent index - NGLs	$0.8 million
$0.50 change in NYMEX - Gas	$3.5 million

2018 First Quarter Production Sensitivities [(e)]

	Production	Production Costs
Brent at $75.00	119 to 124 MBOE per day	$19.50 to $21.00 per BOE
Brent at $65.00	120 to 125 MBOE per day	$19.25 to $20.75 per BOE
Brent at $55.00	123 to 128 MBOE per day	$19.00 to $20.50 per BOE

(a) Realizations exclude hedge effects.

(b) Interest expense includes the amortization of deferred financing costs and 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.

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

(d) 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.

(e) Reflects the effect of price changes on our share of production for the production sharing type contracts at our Wilmington field operations in Long Beach.