NEWS RELEASE

For immediate release

California Resources Corporation Announces Second Quarter 2017 Results

LOS ANGELES, August 3, 2017 – California Resources Corporation (NYSE:CRC), an independent California-based oil and gas exploration and production company, today reported a net loss attributable to common stock (CRC net loss) of $48 million or $1.13 per diluted share for the second quarter of 2017, compared with a net loss of $140 million or $3.51 per diluted share for the second quarter of 2016. For the first six months of 2017, CRC reported net income attributable to common stock (CRC net income) of $5 million or $0.12 per diluted share compared with a net loss of $190 million or $4.85 per diluted share for the same period in 2016.

Adjusted EBITDAX[1] for the second quarter of 2017 was $158 million, compared with $160 million for the second quarter of 2016. Adjusted EBITDAX[1] for the first six months of 2017 was $358 million, compared with $284 million for the same period in 2016. Cash provided by operating activities was $120 million for the first six months of 2017. CRC capital investments for the second quarter of 2017 were $82 million and $132 million for the first six months of 2017, of which $28 million was funded by CRC's joint venture (JV) partner Benefit Street Partners (BSP) in the second quarter and $43 million in the first six months. After taking into account the capital that was funded by BSP for the first six months of 2017, CRC generated free cash flow[1] of $57 million.

Quarterly Highlights Include:

- Produced approximately 129,000 BOE per day
- Invested capital of $82 million, of which JV partner BSP funded $28 million
- Generated adjusted EBITDAX[1] of $158 million, reflecting an adjusted EBITDAX margin[1] of 33%
- Drilled and completed 24 wells with internally funded capital, drilled 8 wells with BSP JV capital and 11 wells with MIRA JV capital

Todd Stevens, President and Chief Executive Officer, said, "During the second quarter of 2017, we expanded our capital activity utilizing joint venture capital. Our team safely ramped up activity to 7 rigs and continued to identify efficiencies and cost savings. In fact, recent wells delivered stronger-than-expected performance at lower-than-expected costs. We expect to build on this success in the third quarter and remain on track to grow production in the second half of the year."

[1] For explanations of how we calculate and use Adjusted EBITDAX (non-GAAP) and Adjusted EBITDAX margin (non-GAAP) and reconciliations of net income / (loss) (GAAP) and net cash (used) provided by operating activities (GAAP) to Adjusted EBITDAX and free cash flow after working capital (non-GAAP), please see Attachment 2.

Second Quarter Results

For the second quarter of 2017, CRC net loss was $48 million or $1.13 per diluted share, compared with a net loss of $140 million or $3.51 per diluted share for the same period of 2016. The 2017 quarterly results reflected higher realized oil, NGL and natural gas prices and improved hedge results, partially offset by lower production volumes, higher production costs resulting from higher natural gas and power prices and higher levels of activity, as well as lower non-operating income from gains on asset divestitures and debt extinguishment. The second quarter 2017 adjusted net loss[2] was $78 million or $1.83 per diluted share, compared with an adjusted net loss of $72 million or $1.80 per diluted share for the same period of 2016. The second quarter 2017 adjusted net loss excluded $35 million of non-cash derivatives gains and a net $5 million charge from other unusual and infrequent items. The second quarter 2016 adjusted net loss excluded $137 million of non-cash derivatives losses, $44 million of gains related to retirements of the Company's notes, a $31 million gain from asset divestitures and a net $6 million charge from other unusual and infrequent items.

Total daily production volumes averaged 129,000 barrels of oil equivalent (BOE) per day for the second quarter of 2017, compared with 140,000 BOE per day for the second quarter of 2016, a decrease of under 8 percent, which is below CRC's estimated base production decline range of 10 to 15 percent. Total daily production decreased 3,000 BOE per day or 2 percent from the first quarter of 2017.

In the second quarter of 2017, realized crude oil prices, including the effect of settled hedges, increased $4.28 per barrel to $47.98 per barrel from $43.70 per barrel in the prior year comparable quarter. Settled hedges increased realized crude oil prices by $1.03 per barrel in the second quarter of 2017 compared with $2.29 per barrel in the prior year comparable quarter. Realized NGL prices increased 33 percent to $30.08 per barrel from $22.54 per barrel in the second quarter of 2016. Realized natural gas prices increased 49 percent to $2.47 per thousand cubic feet (Mcf), compared with $1.66 per Mcf in the same period of 2016.

Production costs for the second quarter of 2017 were $216 million or $18.34 per BOE, compared with $188 million or $14.76 per BOE for the second quarter of 2016. The industry practice for reporting PSC-type contracts can result in higher production costs per barrel as full field operating costs are matched with net production. Excluding the effects of PSC-type contracts, per unit production costs would have been $17.18 and $13.88 for the second quarter of 2017 and 2016, respectively. The increase in production costs was driven by higher natural gas and power prices and the ramp-up of downhole and surface maintenance activity in line with stronger commodity prices. While higher gas prices increase CRC's production costs for power and steam generation, they result in a net benefit to CRC due to higher revenue generated from natural gas sales. General and administrative expenses for the second quarter of 2017 and for the second quarter of 2016 were $61 million.

Taxes other than on income of $31 million for the second quarter of 2017 were $11 million lower than the same period of 2016. Exploration expense of $6 million for the second quarter of 2017 was $1 million higher than the same period of 2016.

Capital investment in the second quarter of 2017 totaled $82 million, of which $55 million was directed to drilling and capital workovers.

Second quarter 2017 cash used by operating activities of $13 million included interest payments of $151 million and property tax payments of $37 million.

[2] For explanations of how we calculate and use Adjusted Net Loss (non-GAAP) and reconciliations to Net Income / (Loss) (GAAP), please see Attachment 2.

Six-Month Results

For the first six months of 2017, CRC net income was $5 million or $0.12 per diluted share, compared with a net loss of $190 million or $4.85 per diluted share for the same period of 2016. The 2017 results reflected higher realized oil, NGL and natural gas prices and improved hedge results, partially offset by lower production volumes, higher production costs resulting from higher natural gas and power prices and higher levels of activity and lower gains on asset divestitures and debt extinguishment. The adjusted net loss[2] for the first six months of 2017 was $121 million or $2.85 per diluted share, compared with an adjusted net loss of $172 million or $4.39 per diluted share for the same period of 2016. The 2017 adjusted net loss excluded $110 million of non-cash derivative gains, $21 million of gains from asset divestitures, $4 million of gains related to retirements of the Company's notes and a net $9 million charge from other unusual and infrequent items. The 2016 adjusted net loss excluded $133 million of gains related to retirements of the Company's notes, $218 million of non-cash derivatives losses, a $31 million gain from asset divestitures, a $63 million tax benefit from a partial reversal of valuation allowances against CRC's deferred tax assets and a net $27 million charge from other unusual and infrequent items.

Total daily production volumes averaged 131,000 BOE per day in the first six months of 2017, compared with 144,000 BOE per day for the same period in 2016, a decrease of 9 percent, which is below CRC's estimated base production decline range. This decrease included a negative effect on production volumes from our production sharing contracts of 1,000 BOE per day.

In the first six months of 2017, realized crude oil prices, including the effect of settled hedges, increased $9.22 per barrel to $49.12 per barrel from $39.90 per barrel for the same period in 2016. Settled hedges increased 2017 realized crude oil prices by $0.42 per barrel, compared with $4.38 per barrel for the same period in 2016. Realized NGL prices increased 66 percent to $32.20 from $19.35 per barrel in the first six months of 2016. Realized natural gas prices increased 45 percent to $2.68 per thousand cubic feet (Mcf), compared with $1.85 per Mcf for the same period in 2016.

Production costs for the first six months of 2017 were $427 million or $18.02 per BOE, compared with $372 million or $14.21 per BOE for the same period in 2016. Per unit production costs, excluding the effect of PSC contracts, were $16.92 and $13.48 per BOE for the first six months of 2017 and 2016, respectively. The increase in production costs was driven by higher natural gas and power prices and the ramp-up of downhole and surface maintenance activity in line with stronger commodity prices. While higher natural gas prices increase CRC's production costs for power and steam generation, they result in a net benefit to the Company due to higher revenue generated from natural gas sales. General and administrative expenses for the first six months of 2017 and the first six months of 2016 were $128 million.

Taxes other than on income of $64 million for the first six months of 2017 were $17 million lower than the same period of 2016. Exploration expense of $12 million for the first six months of 2017 was $2 million higher than the same period of 2016.

Capital investment in the first six months of 2017 totaled $132 million, of which $88 million was directed to drilling and capital workovers.

Cash provided by operating activities for the first six months of 2017 was $120 million and free cash flow after working capital[3] was $57 million after taking into account capital that was funded by BSP.

[3] For explanations of how we calculate and use adjusted Net Loss (non-GAAP) and reconciliation to Net Income/(Loss) (GAAP) and free cash flow after working capital (non-GAAP), please see Attachment 2.

Hedging Update

CRC continues to opportunistically seek hedging transactions to protect its cash flow, operating margins and capital program and to maintain liquidity. Recently, CRC extended its crude oil hedges with swaps for 29,000 barrels per day for the first half of 2018 at an average strike price of $60 Brent, locking in a spread of $15 per barrel above prevailing Brent index if Brent falls below $45. For the second half of 2018, CRC entered into swaps for 4,000 barrel per day at an average strike price of $60 Brent, in addition to locking in a spread of $15 per barrel if Brent falls below $45. See attachment 8 for more details.

Operational Update and 2017 Capital Investment Plan

CRC continued to increase its rig count in the second quarter of 2017 and ended the quarter operating seven rigs. One rig was focused on steamfloods, two rigs on shales, one rig on waterfloods and three rigs on conventional reservoirs. CRC expects one of these rigs will be used for exploration in the second half of the year. An additional rig is anticipated to start up in the third quarter to work on steamfloods for the rest of the year.

With capital from two joint ventures, CRC expects a total 2017 capital program of approximately $400 million. CRC's capital program reflects approximately $17 million in efficiencies and cost savings identified year to date. CRC's 2017 capital program will focus on core fields - Elk Hills, Wilmington, Kern Front, Buena Vista, Mt. Poso, Pleito Ranch, Wheeler Ridge and the delineation of Kettleman North Dome.

CRC has recently closed the second round of funding with BSP and expects the joint ventures to allow CRC to maintain at least a six-rig program for the balance of the year.

Conference Call Details

To participate in today's conference call, 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/10107833. 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 Investor Relations at 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
- operations and operational results including production, hedging, capital investment and expected value creation index (VCI)
- budgets and maintenance capital requirements
- reserves

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. 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 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 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 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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SUMMARY OF RESULTS

($ and shares in millions, except per share amounts)	Second Quarter 2017	Second Quarter 2016	Six Months 2017	Six Months 2016
Statement of Operations Data:				
Revenues and Other				
Oil and gas net sales	**$ 439**	$ 404	**$ 926**	$ 733
Net derivative gains (losses)	**43**	(118)	**116**	(143)
Other revenue	**34**	31	**64**	49
Total revenues and other	**516**	317	**1,106**	639
Costs and Other				
Production costs	**216**	188	**427**	372
General and administrative expenses	**61**	61	**128**	128
Depreciation, depletion and amortization	**138**	138	**278**	285
Taxes other than on income	**31**	42	**64**	81
Exploration expense	**6**	5	**12**	10
Other expenses, net	**25**	24	**47**	47
Total costs and other	**477**	458	**956**	923
Operating Income (Loss)	**39**	(141)	**150**	(284)
Non-Operating Income (Loss)				
Interest and debt expense, net	**(83)**	(74)	**(167)**	(148)
Net gains on early extinguishment of debt	**—**	44	**4**	133
Gains on asset divestitures	**—**	31	**21**	31
Other non-operating expense	**(3)**	—	**(3)**	—
(Loss) Income Before Income Taxes	**(47)**	(140)	**5**	(268)
Income tax benefit	**—**	—	**—**	78
Net (Loss) Income	**(47)**	(140)	**5**	(190)
Net income attributable to noncontrolling interest	**(1)**	—	**—**	—
Net (Loss) Income Attributable to Common Stock	**$ (48)**	$ (140)	**$ 5**	$ (190)
(Loss) Earnings per share (EPS) of common stock - diluted	**$ (1.13)**	$ (3.51)	**$ 0.12**	$ (4.85)
Adjusted Net Loss	**$ (78)**	$ (72)	**$ (121)**	$ (172)
Adjusted EPS - diluted	**$ (1.83)**	$ (1.80)	**$ (2.85)**	$ (4.39)
Weighted-average common shares outstanding - diluted	**42.4**	39.9	**42.7**	39.2
Adjusted EBITDAX	**$ 158**	$ 160	**$ 358**	$ 284
Effective tax rate	**0%**	0%	**0%**	29%
Cash Flow Data:				
Net cash (used) provided by operating activities	**$ (13)**	$ (71)	**$ 120**	$ 44
Net cash (used) provided by investing activities	**$ (74)**	$ 11	**$ (74)**	$ (18)
Net cash provided (used) by financing activities	**$ 46**	$ 52	**$ (49)**	$ (36)

Balance Sheet Data:	**June 30, 2017**	December 31, 2016
Total current assets	**$ 387**	$ 425
Property, plant and equipment, net	**$ 5,738**	$ 5,885
Current maturities of long-term debt	**$ 100**	$ 100
Other current liabilities	**$ 507**	$ 626
Long-term debt, principal amount	**$ 5,069**	$ 5,168
Total equity	**$ (491)**	$ (557)
Outstanding shares as of	**42.8**	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 a measure called "adjusted net income / (loss)" and a measure it calls "adjusted general and administrative expenses" which exclude those items. These non-GAAP 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) and general and administrative expenses 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; and other unusual, out of period and infrequent items. Our management believes 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 first-lien, first-out credit facilities 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.

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) income:

	Second Quarter		Six Months	
($ millions, except per share amounts)	**2017**	2016	**2017**	2016
Net (loss) income attributable to common stock	**$ (48)**	$ (140)	**$ 5**	$ (190)
Unusual and infrequent items:				
Non-cash derivative (gains) losses	**(35)**	137	**(110)**	218
Early retirement, severance and other costs	**—**	4	**3**	18
Gains on asset divestitures	**—**	(31)	**(21)**	(31)
Net gains on early extinguishment of debt	**—**	(44)	**(4)**	(133)
Other	**5**	2	**6**	9
Adjusted income items before taxes	**(30)**	68	**(126)**	81
Reversal of valuation allowance for deferred tax assets [(a)]	**—**	—	**—**	(63)
Total	**$ (30)**	$ 68	**$ (126)**	$ 18
Adjusted net loss	**$ (78)**	$ (72)	**$ (121)**	$ (172)
Net (loss) income attributable to common stock per diluted share	**$ (1.13)**	$ (3.51)	**$ 0.12**	$ (4.85)
Adjusted net loss attributable to common stock per diluted share	**$ (1.83)**	$ (1.80)	**$ (2.85)**	$ (4.39)

(a) Amount represents the out-of-period portion of the 2016 valuation allowance reversal.

DERIVATIVES GAINS AND LOSSES

	Second Quarter		Six Months	
($ millions)	**2017**	2016	**2017**	2016
Non-cash derivative (gains) losses, excluding noncontrolling interest	**$ (35)**	$ 137	**$ (110)**	$ 218
Non-cash derivative losses for noncontrolling interest	**—**	—	**1**	—
Cash proceeds from settled derivatives	**(8)**	(19)	**(7)**	(75)
Net derivative (gains) losses	**$ (43)**	$ 118	**$ (116)**	$ 143

FREE CASH FLOW

($ millions)	Second Quarter 2017	Second Quarter 2016	Six Months 2017	Six Months 2016
Net cash (used) provided by operating activities	**$ (13)**	$ (71)	**$ 120**	$ 44
Capital investment [b]	**(82)**	(5)	**(132)**	(26)
Changes in capital accruals	**9**	(4)	**26**	(11)
Free cash flow (after working capital) [b]	**$ (86)**	$ (80)	**$ 14**	$ 7

(b) Capital investment funded by BSP was $28 million for the second quarter of 2017 and $43 million for the six months ended June 30, 2017. After taking into account the portion of capital funded by BSP, free cash flow for the second quarter was $(58) million and $57 million for the six months ended June 30, 2017.

ADJUSTED GENERAL AND ADMINISTRATIVE EXPENSES

($ millions)	Second Quarter 2017	Second Quarter 2016	Six Months 2017	Six Months 2016
General and administrative expenses	**$ 61**	$ 61	**$ 128**	$ 128
Early retirement and severance costs	**—**	(4)	**(3)**	(18)
Adjusted general and administrative expenses	**$ 61**	$ 57	**$ 125**	$ 110

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)	Second Quarter 2017	Second Quarter 2016	Six Months 2017	Six Months 2016
Net (loss) income attributable to common stock	**$ (48)**	$ (140)	**$ 5**	$ (190)
Interest and debt expense, net	**83**	74	**167**	148
Income tax benefit	**—**	—	**—**	(78)
Depreciation, depletion and amortization	**134**	138	**274**	285
Exploration expense	**6**	5	**12**	10
Adjusted income items before taxes[c]	**(30)**	68	**(126)**	81
Other non-cash items	**13**	15	**26**	28
Adjusted EBITDAX (A)	**$ 158**	$ 160	**$ 358**	$ 284
Net cash (used) provided by operating activities	**$ (13)**	$ (71)	**$ 120**	$ 44
Cash interest	**151**	132	**195**	180
Exploration expenditures	**6**	5	**11**	10
Other changes in operating assets and liabilities	**9**	92	**26**	41
Other, net	**5**	2	**6**	9
Adjusted EBITDAX (A)	**$ 158**	$ 160	**$ 358**	$ 284

(c) See Attachment 2.

ADJUSTED EBITDAX MARGIN

($ millions)	Second Quarter 2017	Second Quarter 2016	Six Months 2017	Six Months 2016
Total Revenues	**$ 516**	$ 317	**$ 1,106**	$ 639
Non-cash derivative (gains) losses, excluding noncontrolling interest	**(35)**	137	**(110)**	218
Adjusted revenues (B)	**$ 481**	**$ 454**	**$ 996**	**$ 857**
Adjusted EBITDAX Margin (A)/(B)	**33%**	**35%**	**36%**	**33%**

ADJUSTED NET INCOME / (LOSS) VARIANCE ANALYSIS

($ millions)

2016 2nd Quarter Adjusted Net Loss	**$**	**(72)**
Price - Oil		34
Price - NGLs		11
Price - Natural Gas		15
Volume		(21)
Production cost rate		(33)
DD&A rate		(9)
Exploration expense		(1)
Interest expense		(9)
Adjusted general & administrative expenses		(4)
All Others		11
2017 2nd Quarter Adjusted Net Loss	**$**	**(78)**

2016 Six-Month Adjusted Net Loss	**$**	**(172)**
Price - Oil		156
Price - NGLs		39
Price - Natural Gas		30
Volume		(62)
Production cost rate		(67)
DD&A rate		(19)
Exploration expense		(2)
Interest expense		(19)
Adjusted general & administrative expenses		(15)
Income tax		(15)
All Others		25
2017 Six-Month Adjusted Net Loss	**$**	**(121)**

PRODUCTION COSTS PER BOE

	Second Quarter				Six Months			
($ millions)		**2017**		2016		**2017**		2016
Production Costs/Boe - as reported	**$**	**18.34**	$	14.76	**$**	**18.02**	$	14.21
Excluding the effects of PSC's		**(1.16)**		(0.88)		**(1.10)**		(0.73)
Production costs/Boe - adjusted	**$**	**17.18**	**$**	**13.88**	**$**	**16.92**	**$**	**13.48**

CAPITAL INVESTMENTS

($ millions)	Second Quarter 2017	Second Quarter 2016	Six Months 2017	Six Months 2016
Internally Funded Capital Investments:				
Conventional	**$ 36**	$ 4	**$ 61**	$ 5
Unconventional	**18**	—	**27**	1
Other	**—**	1	**1**	20 (a)
Total	**$ 54**	$ 5	**$ 89**	$ 26
BSP Capital				
Conventional	**$ 1**	$ —	**$ 1**	$ —
Unconventional	**27**	—	**42**	—
Other	**—**	—	**—**	—
Total	**$ 28**	$ —	**$ 43**	$ —
Consolidated Capital - CRC & BSP	**$ 82**	**$ 5**	**$ 132**	**$ 26**
MIRA Capital	**8**	—	**8**	—
Total Capital - CRC and Partner	**$ 90**	**$ 5**	**$ 140**	**$ 26**

(a) Amount includes $18 million of capital incurred for the turnaround at the Elk Hills Power Plant.

PRODUCTION STATISTICS

Net Oil, NGLs and Natural Gas Production Per Day	Second Quarter		Six Months	
	2017	2016	**2017**	2016
Oil (MBbl/d)				
San Joaquin Basin	**52**	56	**52**	58
Los Angeles Basin	**26**	29	**27**	31
Ventura Basin	**5**	5	**5**	5
Sacramento Basin	**—**	—	**—**	—
Total	**83**	90	**84**	94
NGLs (MBbl/d)				
San Joaquin Basin	**15**	15	**15**	16
Los Angeles Basin	**—**	—	**—**	—
Ventura Basin	**1**	1	**1**	1
Sacramento Basin	**—**	—	**—**	—
Total	**16**	16	**16**	17
Natural Gas (MMcf/d)				
San Joaquin Basin	**141**	152	**141**	149
Los Angeles Basin	**—**	4	**1**	3
Ventura Basin	**8**	9	**8**	9
Sacramento Basin	**33**	37	**33**	38
Total	**182**	202	**183**	199
Total Production (MBoe/d) [(a)]	**129**	140	**131**	144

(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. The price of natural gas on a BOE basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, for the six months ended June 30, 2017, the average prices of Brent oil and NYMEX natural gas were $52.79 per Bbl and $3.20 per MMBtu, respectively, resulting in an oil-to-gas price ratio of approximately 16 to 1.

PRICE STATISTICS

	Second Quarter		Six Months	
	2017	2016	**2017**	2016
Realized Prices				
Oil with hedge ($/Bbl)	**$ 47.98**	$ 43.70	**$ 49.12**	$ 39.90
Oil without hedge ($/Bbl)	**$ 46.95**	$ 41.41	**$ 48.70**	$ 35.52
NGLs ($/Bbl)	**$ 30.08**	$ 22.54	**$ 32.20**	$ 19.35
Natural gas ($/Mcf)	**$ 2.47**	$ 1.66	**$ 2.68**	$ 1.85
Index Prices				
Brent oil ($/Bbl)	**$ 50.92**	$ 46.97	**$ 52.79**	$ 41.03
WTI oil ($/Bbl)	**$ 48.29**	$ 45.59	**$ 50.10**	$ 39.52
NYMEX gas ($/MMBtu)	**$ 3.14**	$ 1.97	**$ 3.20**	$ 2.02
Realized Prices as Percentage of Index Prices				
Oil with hedge as a percentage of Brent	**94%**	93%	**93%**	97%
Oil without hedge as a percentage of Brent	**92%**	88%	**92%**	87%
Oil with hedge as a percentage of WTI	**99%**	96%	**98%**	101%
Oil without hedge as a percentage of WTI	**97%**	91%	**97%**	90%
NGLs as a percentage of Brent	**59%**	48%	**61%**	47%
NGLs as a percentage of WTI	**62%**	49%	**64%**	49%
Natural gas as a percentage of NYMEX	**79%**	84%	**84%**	92%

SECOND QUARTER DRILLING ACTIVITY

Wells Drilled (Net)	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Development Wells					
Primary	6	—	—	—	6
Waterflood	9	4	—	—	13
Steamflood	20	—	—	—	20
Unconventional	4	—	—	—	4
Total	39	4	—	—	43
Exploration Wells					
Primary	—	—	—	—	—
Waterflood	—	—	—	—	—
Steamflood	—	—	—	—	—
Unconventional	—	—	—	—	—
Total	—	—	—	—	—
Total Wells (a), (b)	39	4	—	—	43
CRC Wells Drilled	20	4	—	—	24
BSP Wells Drilled	8	—	—	—	8
MIRA Wells Drilled - Net	11	—	—	—	11
Development Drilling Capital - CRC & BSP ($ millions)	$27	$6	$1	$—	$34
Development Drilling Capital - MIRA ($ millions)	$8	$—	$—	$—	$8

(a) Includes 10 steam injectors and 2 water injectors.
(b) Includes drilled but uncompleted wells.

HEDGES - CURRENT

	3Q 2017	4Q 2017	1Q 2018	2Q 2018	3Q 2018	4Q 2018	FY 2019	FY 2020
Crude Oil								
Calls:								
Barrels per day	6,100	6,300	16,800	16,200	16,100	16,100	1,000	900
Weighted-average Brent price per barrel	$57.73	$57.80	$58.86	$58.92	$58.91	$58.91	$60.00	$60.00
Purchased Puts:								
Barrels per day	18,100	11,300	1,200	1,200	1,100	1,100	1,000	900
Weighted-average Brent price per barrel	$50.63	$47.75	$45.82	$45.83	$45.83	$45.85	$45.84	$43.91
Sold Puts:								
Barrels per day	—	—	29,000	29,000	4,000	4,000	—	—
Weighted-average Brent price per barrel	$—	$—	$45.00	$45.00	$45.00	$45.00	$—	$—
Swaps:								
Barrels per day	25,000	25,000	29,000	29,000	4,000	4,000	—	—
Weighted-average Brent price per barrel	$54.99	$54.99	$60.00	$60.00	$60.00	$60.00	$—	$—

For purchased puts, we would receive settlement payments for prices below the indicated weighted-average price per barrel. For our sold puts, we would make settlement payments for prices below the indicated weighted-average price per barrel. From time to time, we use puts in conjunction with other derivatives to increase the efficacy of our hedging activities.

Some of our fourth quarter 2017 swaps grant our counterparties the option to increase volumes by up to 10,000 barrels per day at a weighted-average Brent price of $55.46. As of June 30, 2017, our counterparties also have options to further increase swap volumes for the first half of 2018 by up to 10,000 barrels per day at a weighted-average Brent price of $60.00. Additionally, our counterparties have quarterly options to further increase swap volumes for the first half of 2018 by up to 19,000 barrels and for the second half of 2018 by up to 4,000 barrels at a weighted-average Brent price of $60.00.

2017 THIRD QUARTER GUIDANCE

Anticipated Realizations Against the Prevailing Index Prices for Q3 2017 [a]

Oil	90% to 94% of Brent
NGLs	58% to 62% of Brent
Natural Gas	84% to 88% of NYMEX

2017 Third Quarter Production, Capital and Income Statement Guidance

Production	127 to 132 MBOE per day
Capital	$115 million to $135 million
Production costs	$18.35 to $18.85 per BOE
Adjusted general and administrative expenses	$5.30 to $5.60 per BOE
Depreciation, depletion and amortization	$11.50 to $11.80 per BOE
Taxes other than on income[b]	$36 million to $40 million
Exploration expense	$3 million to $7 million
Interest expense [c]	$83 million to $87 million
Cash Interest [c]	$55 million to $59 million
Income tax expense rate	0%
Cash tax rate	0%

	On Income	On Cash
Pre-tax Third Quarter Price Sensitivities		
$1 change in Brent index - Oil (above $55.00 Brent) [d]	$3.9 million	$3.9 million
$1 change in Brent index - NGLs	$0.8 million	$0.8 million
$0.50 change in NYMEX - Gas	$2.0 million	$2.0 million

Third Quarter Volumes Sensitivities

$1 change in the Brent index [e]	300 Bbl/d

(a) Realizations exclude hedge effects.

(b) Taxes other than on income are expected to be higher in the third quarter primarily due to increased production taxes.

(c) Interest expense includes the amortization of 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.

(d) At a Brent index price between $50.00 and $55.00, the sensitivity goes up to approximately $4.3 million. Below $50.00 Brent, the sensitivity drops to approximately $2.8 million.

(e) Reflects the effect of production sharing type contracts in our Wilmington field operations.