California Resources Corp. (NYSE:CRC), an independent California-based oil and gas exploration and production company, today reported a net loss of $77 million or $1.83 per diluted share for the fourth quarter of 2016. For the full year of 2016 net income was $279 million or $6.76 per diluted share, compared with a net loss of $3.6 billion or $92.79 per diluted share for the same period of 2015. Additionally, CRC announced 2016 reserves of 568 million barrels of oil equivalent (BOE) and 2017 capital investment plans of $300 million.

This Smart News Release features multimedia. View the full release here: http://www.businesswire.com/news/home/20170216006267/en/

CRC 4Q16 Earnings Infographic (Graphic: Business Wire)

Adjusted EBITDAX[1] for the fourth quarter and the full year of 2016 was $168 million and $616 million, respectively, compared with $226 million and $906 million for the fourth quarter and the full year of 2015. CRC had annual operating cash flow of $130 million in 2016 and capital investments of $75 million. This financial discipline allowed CRC to generate $49 million of free cash flow after working capital[1].

Highlights Include:

- Received sixth bank amendment removing capital investment limitations and allowing additional joint ventures, among other changes
- Initial 2017 capital investment plan of $300 million
- 2016 capital investment of $75 million with only $31 million of drilling and workover capital
- Quarterly production of 135,000 BOE per day
    - A 2.2% sequential decline
    - A 10% year-over-year decline, excluding PSC effects
- Annual production of 140,000 BOE per day
- Annual production costs down 16% from prior year
- Annual operating cash flow of $130 million
- 2016 Annual free cash flow[2] after working capital of $49 million
- 2016 Organic reserve replacement ratio of 71% with minimal drilling and workover capital
- 2016 Adjusted Organic F&D costs of $3.42 per BOE[3] excluding price adjustments

[1,2] For explanations of how we calculate and use Adjusted Net Loss (non-GAAP) and Adjusted EBITDAX (non-GAAP) and reconciliations of net income / (loss) (GAAP) and net cash provided by operating activities (GAAP) to Adjusted EBITDAX and free cash flow after working capital (non-GAAP), please see Attachments 2 and 3.
[3] See calculation of F&D on attachment 4.

Todd Stevens, President and Chief Executive Officer, said, "We are pleased with our 2016 performance as we strengthened our balance sheet, continued to live within our cash flows, managed our base production to a minimal decline and increased our probable and possible reserves significantly. These achievements reflect the diligence of our team as well as the resiliency of our operations and complementary infrastructure.

"Our planned 2017 capital budget of about $300 million should allow us to increase activity, enhance margins and return to a growth profile beginning in the second half of the year. Additionally, we expect to further expand our actionable inventory. We are pleased to have received our sixth bank amendment which removed capital investment limitations. We will continue to align our investments with our cash flow."

Fourth Quarter Results

For the fourth quarter of 2016, CRC reported a net loss of $77 million or $1.83 per diluted share, compared with a net loss of $3.3 billion or $85.47 per diluted share for the same period of 2015. The 2016 quarter reflected slightly lower realized oil prices including the effect of settled hedges. Compared to the prior year period, the 2016 quarter also reflected higher realized NGL and natural gas prices and lower costs, partially offset by lower volumes, while the 2015 quarter included a non-cash, after-tax impairment charge of $2.9 billion ($4.9 billion pre-tax) and other items. The fourth quarter 2016 adjusted net loss was $74 million or $1.76 per diluted share, compared with an adjusted net loss of $77 million or $2.01 per diluted share for the same period of 2015. The 2016 adjusted net loss excluded $40 million of non-cash derivative losses on outstanding hedges, $12 million of net gains on the early extinguishment of certain of the Company's notes, and $25 million of net gains from other miscellaneous, infrequent items. The 2015 adjusted net loss excluded the impairment charge described above, a $294 million valuation allowance for deferred assets and other after-tax write-offs of $36 million largely reflecting the impact of lower prices on other assets.

Adjusted EBITDAX for the fourth quarter of 2016 was $168 million, compared to $226 million for the same period of 2015.

Total daily production volumes averaged 135,000 barrels of oil equivalent (BOE) for the fourth quarter of 2016, compared with 155,000 BOE for the fourth quarter of 2015, a decrease of less than 13 percent, which is within CRC's estimated base production decline range. This decrease included effects of production sharing contracts (or "PSC") of 4,000 BOE per day. Excluding this PSC effect, the year-over-year quarterly decline would have been 10 percent. The fourth quarter 2016 production decline continued to reflect management's decision to withhold development capital and to selectively defer workover and downhole maintenance activity in the early part of the year. Due to the improved commodity price environment in the second half of the year, the Company began increasing its activity levels, particularly in the fourth quarter, resulting in lower quarterly sequential declines. In the fourth quarter of 2016, realized crude oil prices, including the effect of settled hedges, decreased $0.40 per barrel to $45.48 per barrel from $45.88 per barrel in the prior year comparable quarter. Settled hedges reduced realized crude oil prices by $1.12 per barrel in the fourth quarter of 2016, while increasing the fourth quarter 2015 realized prices by $6.47 per barrel. Realized NGL prices increased 48 percent to $28.99 per barrel from $19.56 per barrel in the fourth quarter of 2015. Realized natural gas prices increased 14 percent to $2.79 per thousand cubic feet (Mcf), compared with $2.44 per Mcf in the same period of 2015. The fourth quarter 2015 realized natural gas prices included $0.16 per Mcf from settled hedges.

Production costs for the fourth quarter of 2016 were $217 million or $17.50 per BOE, compared with $221 million or $15.51 per BOE for the fourth quarter of 2015, a 2-percent reduction on an absolute dollar basis. The decrease was driven by well servicing efficiencies and lower energy costs. The fourth quarter of 2016 also reflected $10 million in higher compensation costs than the comparable 2015 quarter. General and administrative (G&A) expenses were $62 million or $5.00 per BOE for the fourth quarter of 2016, compared with $64 million or $4.48 per BOE for the fourth quarter of 2015. The decrease in total G&A expenses reflects employee and contractor cost-reduction initiatives offset by higher employee compensation resulting from a significant increase in the stock price in the fourth quarter of 2016. Adjusted G&A expenses for the fourth quarter of 2016 were $61 million or $4.92 per BOE, compared with $69 million or $4.80 per BOE for the fourth quarter of 2015. Taxes other than on income of $26 million for the fourth quarter of 2016 were $4 million lower than the same period of 2015. Exploration expenses of $10 million for the fourth quarter of 2016 were $3 million higher than the same period of 2015.

Capital investment in the fourth quarter of 2016 totaled $31 million, of which $20 million was directed to drilling and capital workovers.

Full Year 2016 Results

For the full year of 2016, CRC reported net income of $279 million or $6.76 per diluted share, compared with a net loss of $3.6 billion or $92.79 per diluted share in 2015. The 2016 income reflected the net gains from the early extinguishment of the Company's notes and divestiture of assets as well as lower costs, partially offset by lower oil and natural gas prices and volumes and non-cash derivative losses on outstanding hedges, while 2015 also included the fourth-quarter impairment charge and other items. The 2016 adjusted net loss was $317 million or $7.85 per diluted share, compared with an adjusted net loss of $311 million or $8.12 per diluted share for 2015. The 2016 adjusted net loss excluded $805 million of net gains on the early extinguishment of the Company's notes, $283 million of non-cash derivative losses on outstanding hedges, a $63 million benefit from a deferred tax valuation allowance adjustment, a $20 million charge resulting from employee reductions that were made during the year, a $30 million gain from asset divestitures, a $12 million write-off of deferred financing costs related to the retirement of the Company's notes and $13 million net gains from other miscellaneous, infrequent charges. The 2015 adjusted net loss excluded a non-cash, after-tax impairment charge of $2.9 billion ($4.9 billion pre-tax), a $294 million valuation allowance for deferred assets, $52 million of non-cash derivative gains, a $71 million charge reflecting the effect of prices on other assets, $67 million of severance and early retirement costs, and $19 million net from other infrequent net charges and related tax adjustments.

Adjusted EBITDAX for the full year of 2016 was $616 million, compared to $906 million in the prior-year period.

Total daily production volumes averaged 140,000 BOE for the full year of 2016, compared with 160,000 BOE for the full year of 2015, a 12.5-percent decrease which is within CRC's estimated base production decline range. Excluding the PSC effects, the annual decline would have been under 12 percent. CRC's year-over-year average oil production was 91,000 barrels per day for the full year of 2016, a decrease of under 13 percent, or 13,000 barrels per day, compared with the same period of 2015. NGL production decreased by 11 percent to 16,000 barrels per day and natural gas production decreased by 14 percent to 197 million cubic feet (MMcf) per day.

Realized crude oil prices, including the effect of settled hedges, decreased 15 percent to $42.01 per barrel for 2016 from $49.19 per barrel in 2015. Hedges contributed $2.29 per barrel to realized crude oil prices for 2016, compared with $2.04 for the same period of 2015. Realized NGL prices increased 14 percent to $22.39 per barrel for 2016 from $19.62 per barrel in 2015. Realized natural gas prices decreased 14 percent to $2.28 per Mcf for 2016, compared with $2.66 per Mcf in the same period of 2015.

Production costs for 2016 were $800 million or $15.61 per BOE, compared with $951 million or $16.30 per BOE for the same period in 2015, a 16-percent reduction on an absolute dollar basis. The decrease reflected cost reductions throughout CRC's operations, particularly in well servicing efficiency, lower personnel costs, lower energy use and lower natural gas prices, as well as lower workover and downhole maintenance activity in 2016. G&A expenses were $248 million or $4.84 per BOE for the full year of 2016, compared with $354 million or $6.07 per BOE for the same period of 2015, reflecting employee and contractor cost-reduction initiatives and greater severance and early retirement costs included in the prior-year period. Adjusted G&A expenses were $228 million or $4.45 per BOE for the full year of 2016, compared with $287 million or $4.92 per BOE for the same period of 2015. Adjusted G&A expenses for both years excluded severance and early retirement. Exploration expenses of $23 million for the full year of 2016 were $13 million lower than the same period of 2015. Taxes other than on income were $144 million for 2016, compared to $180 million for 2015. The decrease was largely due to a reduction in property taxes.

Consistent with our operating tenet of living within cash flow, the Company generated $130 million of operating cash flow and free cash flow after capital of $49 million for the full year of 2016.

2016 Proved Reserves and PV-10 Value

CRC’s proved reserves estimates for the year ended December 31, 2016, as audited by Ryder Scott, were 568 million BOE, consisting of 72 percent oil and 71 percent proved developed volumes. The Company achieved a total organic reserves replacement ratio (RRR)[(4)] of 71 percent of 2016 production, excluding price adjustments. Price-related adjustments reduced overall reserves by 60 million BOE. Volumes that have been removed from the reserves base due to lower prices are expected to return to CRC's proved base at higher prices of crude oil.

Summary of Changes in Proved Reserves (Million BOE)

Balance at December 31, 2015	644
Revision of Previous Estimates (Performance-Related)	13
Extensions and Discoveries	20
Improved Recovery	3
Divestiture of Proved Reserves	(1)
Price-Related Revisions	(60)
Production	(51)
Balance at December 31, 2016	568*
2016 Organic F&D cost, excluding price adjustments[(5)]	$3.42

*Calculated using the first-day-of-the-month twelve-month average Brent oil price of $42.90 per barrel and Henry Hub price of $2.48 per million British Thermal units (BTU) for natural gas, before adjustments for gravity, quality and transportation costs, in accordance with Securities and Exchange Commission (SEC) guidelines.
[4,5] See calculation of RRR and F&D on attachment 4.

The present value of CRC's proved reserves as of December 31, 2016 was approximately $2.8 billion, on a pre-tax basis, discounted at 10 percent (PV-10)[(6)]. The reduction from the prior year amount of $5.1 billion, resulted from a 23-percent and 4-percent decrease in crude oil prices and natural gas prices, respectively. The effect of price decreases was partially offset by reserves additions, cost reductions and efficiencies identified in the Company's life-of-field plans. Utilizing current costs, a flat $55 Brent crude oil price deck and $3.30/Mcf Henry Hub natural gas price, which is similar to the 2015 SEC pricing and the current strip prices, CRC's proved reserves would be approximately 686 million barrels. Using these same assumptions, the PV-10 would be nearly $5.4 billion for proved reserves and $9.7 billion for proved, probable and possible reserves.

[6] PV-10 is a non-GAAP financial measure. For a reconciliation to the GAAP standardized measure of discounted future net cash flows, see attachment 4.

Hedging Update

CRC continues to opportunistically add hedges to protect its cash flow, margins and capital program and to maintain liquidity. For example, currently we have hedges in place covering over 45% of our projected first quarter 2017 oil production. See attachment 11 for more details.

Operational Update and 2017 Capital Investment Plan

CRC operated two drilling rigs at year end 2016 with one in the San Joaquin basin and one in the Los Angeles basin. In the fourth quarter, CRC drilled 4 waterflood wells and 17 steamflood wells. By the end of the first quarter of 2017, we anticipate having four rigs running (three in the San Joaquin basin and one in the Los Angeles basin).

Consistent with prior years, CRC expects to align our capital investment with our operational cash flow, and adjust our capital plan accordingly. Based on the current market conditions, CRC will begin the year with a capital investment plan of $300 million, consisting of approximately $150 million for drilling and completions, $50 million for capital work-overs, $50 million for facilities, $25 million for exploration and $25 million primarily for mechanical integrity projects. Our 2017 development program will focus primarily on our core fields- Elk Hills, Wilmington, Kern Front, Buena Vista, and the delineation of Kettleman North Dome. We have developed a dynamic plan which can be scaled up or down depending on the price environment. For 2017, we have action plans that allow us to reduce our capital investment to under $100 million or increase it to as high as $500 million based on conditions during the year. Going forward, we will continue to focus on identifying, evaluating and pursuing value creation opportunities that strengthen our balance sheet and reduce our financial leverage.

CRC Analyst Day and Site Tour

We are pleased to announce that CRC is hosting a 2017 Analyst Day and Site Tours in the Bakersfield and Long Beach areas in California on March 22-23. Due to the length of the event, logistical considerations and safety requirements, space will be limited. We will be webcasting the formal presentations and will post them to CRC's investor relations page on our website at www.crc.com. The event will be archived for play later on the day of the presentations.

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/10097714. 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 Corp. 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 integrated infrastructure to gather, process and market its production. Using advanced technology, California Resources Corp. 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 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.

We have provided internally generated estimates of PV-10 for proved reserves and aggregated proved, probable and possible reserves (“3P Reserves”) as of December 31, 2016 in this presentation, with each category of reserves estimated in accordance with SEC guidelines and definitions, though we have not reported all such estimates to the SEC. As used in this presentation:

Probable reserves. We use deterministic methods to estimate probable reserve quantities, and when deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves.

Possible reserves. We use deterministic methods to estimate possible reserve quantities, and when deterministic methods are used to estimate possible reserve quantities, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves.

The SEC prohibits companies from aggregating proved, probable and possible reserves estimated using deterministic estimation methods in filings with the SEC due to the different levels of certainty associated with each reserve category.

Actual quantities that may be ultimately recovered from our interests may differ substantially from the estimates in this release. Factors affecting ultimate recovery include the scope of our ongoing drilling and workover program, which will be directly affected by commodity prices, the availability of capital, regulatory approvals, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints and other factors; actual drilling results, which may be affected by geological, mechanical and other factors that determine recovery rates; and budgets based upon our future evaluation of risk, returns and the availability of capital.

Attachment 1

SUMMARY OF RESULTS

	Fourth Quarter		Twelve Months	
($ and shares in millions, except per share amounts)	2016	2015	2016	2015
Statement of Operations Data:				
Revenues and Other				
Oil and gas net sales	$ 464	$ 447	$ 1,621	$ 2,134
Net derivative (losses) gains	(49)	83	(206)	133
Other revenue	37	36	132	136
Total revenues and other	452	566	1,547	2,403
Costs and Other				
Production costs	217	221	800	951
General and administrative expenses	62	64	248	354
Depreciation, depletion and amortization	137	247	559	1,004
Asset impairments	—	4,852	—	4,852
Taxes other than on income	26	30	144	180
Exploration expense	10	7	23	36
Other expenses, net	3	94	79	168
Total costs and other	455	5,515	1,853	7,545
Operating Loss	(3)	(4,949)	(306)	(5,142)
Non-Operating (Loss) Income				
Interest and debt expense, net	(85)	(82)	(328)	(326)
Net gains on early extinguishment of debt	12	20	805	20
Other non-operating (expense) income	(1)	(28)	30	(28)
(Loss) Income Before Income Taxes	(77)	(5,039)	201	(5,476)
Income tax benefit	—	1,757	78	1,922
Net (Loss) Income	$ (77)	$ (3,282)	$ 279	$ (3,554)
EPS - diluted	$ (1.83)	$ (85.47)	$ 6.76	$ (92.79)
Adjusted Net Loss	$ (74)	$ (77)	$ (317)	$ (311)
Adjusted EPS - diluted	$ (1.76)	$ (2.01)	$ (7.85)	$ (8.12)
Weighted average diluted shares outstanding	42.1	38.4	40.4	38.3
Adjusted EBITDAX	$ 168	$ 226	$ 616	$ 906
Effective tax rate	0 %	35 %	(39)%	35 %
Cash Flow Data:				
Net cash (used) provided by operating activities	$ (15)	$ (9)	$ 130	$ 403
Net cash used by investing activities	$ (30)	$ (215)	$ (61)	$ (757)
Net cash (used) provided by financing activities	$ 47	$ 232	$ (69)	$ 352

Balance Sheet Data:	December 31, 2016	December 31, 2015
Total current assets	$ 425	$ 438
Property, plant and equipment, net	$ 5,885	$ 6,312
Total current liabilities	$ 726	$ 605
Long-term debt, principal amount	$ 5,168	$ 6,043
Total equity	$ (557)	$ (916)
Outstanding shares as of	42.5	38.8

Attachment 2

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

Our results of operations can include the effects of unusual 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 GAAP.

The following table presents a reconciliation of the GAAP financial measure of net (loss) income to the non-GAAP financial measure of adjusted net (loss) income:

	Fourth Quarter		Twelve Months	
($ millions, except per share amounts)	2016	2015	2016	2015
Net (loss) income	$ (77)	$ (3,282)	$ 279	$ (3,554)
Unusual and infrequent items:				
Asset impairments	—	4,852	—	4,852
Write-down of certain assets	—	71	—	71
Non-cash derivative losses (gains)	40	(19)	283	(52)
Severance, early retirement and other costs	1	(5)	20	67
Refunds, plant turnaround charges and other	(27)	5	(13)	11
Net gains on early extinguishment of debt	(12)	(20)	(805)	(20)
Debt issuance costs	—	28	—	28
Loss (gain) from asset divestitures	1	—	(30)	—
Adjusted income items before interest and taxes	3	4,912	(545)	4,957
Deferred debt issuance costs write-off	—	—	12	—
Adjustments for valuation allowance on deferred tax assets	—	294	(63) [a]	294
Tax effects of these items and related adjustments	—	(2,001)	—	(2,008)
Total	$ 3	$ 3,205	$ (596)	$ 3,243
Adjusted net loss	$ (74)	$ (77)	$ (317)	$ (311)
Net (loss) income per diluted share	$ (1.83)	$ (85.47)	$ 6.76	$ (92.79)
Adjusted net loss per diluted share	$ (1.76)	$ (2.01)	$ (7.85)	$ (8.12)

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

DERIVATIVES GAINS AND LOSSES

	Fourth Quarter		Twelve Months	
($ millions)	2016	2015	2016	2015
Non-cash derivative losses (gains)	$ 40	$ (19)	$ 283	$ (52)
Payments (proceeds) from settled derivatives	9	(64)	(77)	(81)
Net derivative losses (gains)	$ 49	$ (83)	$ 206	$ (133)

FREE CASH FLOW

	Fourth Quarter		Twelve Months	
($ millions)	2016	2015	2016	2015
Operating cash flow	$ (15)	$ (9)	$ 130	$ 403
Capital investment	(31)	(78)	(75)	(401)
Changes in capital accruals	(1)	(3)	(6)	(205)
Free cash flow (after working capital)	$ (47)	$ (90)	$ 49	$ (203)

ADJUSTED GENERAL AND ADMINISTRATIVE EXPENSES

	Fourth Quarter		Twelve Months	
($ millions)	2016	2015	2016	2015
General and administrative expenses	$ 62	$ 64	$ 248	$ 354
Severance, early retirement and other costs	(1)	5	(20)	(67)
Adjusted general and administrative expenses	$ 61	$ 69	$ 228	$ 287

Attachment 3

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

We define adjusted EBITDAX as earnings before interest expense; income taxes; depreciation, depletion and amortization; exploration expense; and other unusual 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 U.S. generally accepted accounting principles (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 tables present a reconciliation of the GAAP financial measures of net (loss) / income and net cash (used) / provided by operating activities to the non-GAAP financial measure of adjusted EBITDAX:

	Fourth Quarter		Twelve Months	
($ millions)	2016	2015	2016	2015
Net (loss) income	$ (77)	$ (3,282)	$ 279	$ (3,554)
Interest and debt expense	85	82	328	326
Income tax benefit	—	(1,757)	(78)	(1,922)
Depreciation, depletion and amortization	137	247	559	1,004
Exploration expense	10	7	23	36
Adjusted income items before interest and taxes[a]	3	4,912	(545)	4,957
Other items	10	17	50	59
Adjusted EBITDAX	168	226	616	906
Net cash (used) provided by operating activities	$ (15)	$ (9)	$ 130	$ 403
Cash Interest	140	111	384	359
Exploration expenditures	7	7	20	27
Other changes in operating assets and liabilities	63	112	95	106
Refunds, plant turnaround charges and other	(27)	5	(13)	11
Adjusted EBITDAX	168	226	616	906

(a) See Attachment 2.

Attachment 4

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

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

PV-10 and Standardized Measure ($ millions)	2016
PV-10 of proved reserves [1]	$ 2,848
Present value of future income taxes discounted at 10%	(181)
Standardized measure of discounted future net cash flows	$ 2,667

(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. PV-10 and Standardized Measure are used by the industry and by our management as an asset value measure to compare against our past reserves bases and the reserves bases of other business entities because the pricing, cost environment and discount assumptions are prescribed by the SEC and are comparable. PV-10 further facilitates the comparisons to other companies as it is not dependent on the tax paying status of the entity.

Organic Reserve Replacement Ratio [2]	2016	
Proved reserves added - MMBOE		
Extensions and Discovery	20	
Improved Recovery	3	
Revisions related to performance	13	
Total (A)	36	
Production in 2016 - MMBOE (B)	51	
Organic Reserves Replacement Ratio (A)/(B)	71	%

(2) The organic reserves replacement ratio is calculated for a specified period using the proved oil-equivalent additions from extensions and discoveries, improved recovery, and performance-related provisions, divided by oil-equivalent production. Approximately 89% of the additions for 2016 are proved undeveloped. There is no guarantee that historical sources of reserves additions will continue as many factors could cause unforeseen results, including geology, government regulations and permits, commodity prices, the availability of capital, the effectiveness of development plans and other factors that affect reserves additions and are partially or fully outside management's control. Management uses this measure to gauge results of its capital allocation.

Organic Finding and Development Costs[3]	2016	
Organic costs incurred - in millions (A)	$ 123	[4]

Proved Reserves Added - MMBOE (B)	36	(5)
Organic Finding and Development Costs - $/BOE (A)/(B)	$ 3.42	

(3) We calculate organic finding and development costs by dividing the costs incurred for the year from the capital program (including development, including asset retirement obligations, and exploration costs, but excluding acquisitions) by the amount of oil-equivalent proved reserves added in the same year from improved recovery, extensions and discoveries and performance-related revisions (excluding acquisitions and price-related revisions). 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 GAAP disclosures. Various factors, including timing differences and effects of commodity price changes, can cause finding and development costs to reflect costs associated with particular reserves imprecisely. 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 2016 costs were incurred to convert proved undeveloped reserves from prior years to proved developed reserves. Our calculations of finding and development costs may not be comparable to similar measures provided by other companies. We have not estimated future costs expected for the reserves added or removed costs related to reserves added in prior periods.

(4) Includes development and exploration costs, as well as asset retirement obligations.

(5) Includes performance revisions.

Attachment 5

ADJUSTED NET INCOME / (LOSS) VARIANCE ANALYSIS

($ millions)

2015 4th Quarter Adjusted Net Loss	$ (77)
Price - Oil	(2)
Price - NGLs	15
Price - Natural Gas	7
Volume	(47)
Production cost rate	(4)
DD&A rate	91
Exploration expense	(3)
Interest expense	(3)
Adjusted general & administrative expenses	8
Income tax	(50)
All Others	(9)
2016 4th Quarter Adjusted Net Loss	$ (74)
2015 Twelve Month Adjusted Net Loss	$ (311)
Price - Oil	(283)
Price - NGLs	19
Price - Natural Gas	(31)
Volume	(116)
Production cost rate	122
DD&A rate	376
Exploration expense	13
Interest expense	10
Adjusted general & administrative expenses	59
Income tax	(193)
All Others	18
2016 Twelve Month Adjusted Net Loss	$ (317)

Attachment 6

CAPITAL INVESTMENTS

	Fourth Quarter		Twelve Months	
($ millions)	2016	2015	2016	2015
Capital Investments:				
Conventional	$ 22	$ 62	$ 41	$ 328
Unconventional	6	8	12	25
Exploration	1	—	1	17
Other (a)	2	8	21	31
	$ 31	$ 78	$ 75	$ 401

(a) Twelve months of 2016 includes $19 million of capital incurred for the planned turnaround at the Elk Hills Power Plant, of which payment of $10 million is deferred to future periods.

Attachment 7

PRODUCTION STATISTICS

	Fourth Quarter		Twelve Months	
Net Oil, NGLs and Natural Gas Production Per Day	2016	2015	2016	2015
Oil (MBbl/d)				
San Joaquin Basin	55	61	57	64
Los Angeles Basin	27	35	29	34

Ventura Basin	5	6	5	6
Sacramento Basin	—	—	—	—
Total	87	102	91	104
NGLs (MBbl/d)				
San Joaquin Basin	14	17	15	17
Los Angeles Basin	—	—	—	—
Ventura Basin	1	1	1	1
Sacramento Basin	—	—	—	—
Total	15	18	16	18
Natural Gas (MMcf/d)				
San Joaquin Basin	152	161	150	172
Los Angeles Basin	1	2	3	2
Ventura Basin	8	9	8	11
Sacramento Basin	34	40	36	44
Total	195	212	197	229
Total Barrels of Oil Equivalent (MBoe/d) [(a)]	135	155	140	160

(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 barrel of oil equivalent 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 year ended December 31, 2016, the average prices of Brent oil and NYMEX natural gas were $45.04 per Bbl and $2.42 per MMBtu, respectively, resulting in an oil-to-gas price ratio of approximately 19 to 1.

Attachment 8

PRICE STATISTICS

	Fourth Quarter		Twelve Months	
	2016	2015	2016	2015
Realized Prices				
Oil with hedge ($/Bbl)	$45.48	$45.88	$42.01	$ 49.19
Oil without hedge ($/Bbl)	$46.60	$39.41	$39.72	$ 47.15
NGLs ($/Bbl)	$28.99	$19.56	$22.39	$ 19.62
Natural gas with hedge ($/Mcf)	$2.79	$2.44	$2.28	$ 2.66
Natural gas without hedge ($/Mcf)	$2.79	$2.28	$2.28	$ 2.61
Index Prices				
Brent oil ($/Bbl)	$51.13	$44.71	$45.04	$ 53.64
WTI oil ($/Bbl)	$49.29	$42.18	$43.32	$ 48.80
NYMEX gas ($/MMBtu)	$2.95	$2.44	$2.42	$ 2.75

Realized Prices as Percentage of Index Prices					
Oil with hedge as a percentage of Brent	89	% 103	% 93	% 92	%
Oil without hedge as a percentage of Brent	91	% 88	% 88	% 88	%
Oil with hedge as a percentage of WTI	92	% 109	% 97	% 101	%
Oil without hedge as a percentage of WTI	95	% 93	% 92	% 97	%
NGLs as a percentage of Brent	57	% 44	% 50	% 37	%
NGLs as a percentage of WTI	59	% 46	% 52	% 40	%
Natural gas with hedge as a percentage of NYMEX	95	% 100	% 94	% 97	%
Natural gas without hedge as a percentage of NYMEX	95	% 93	% 94	% 95	%

Attachment 9

2017 FIRST QUARTER GUIDANCE

Anticipated Realizations Against the Prevailing Index Prices for Q1 2017 [(a)]		
Oil	88% to 92% of Brent	
NGLs	50% to 55% of Brent	
Natural Gas	90% to 94% of NYMEX	
2017 First Quarter Production, Capital and Income Statement Guidance		
Production	128 to 133 MBOE per day	
Capital	$60 million to $70 million	
Production costs	$18.10 to $18.60 per BOE	
Adjusted general and administrative expenses	$5.35 to $5.65 per BOE	
Depreciation, depletion and amortization	$11.65 to $11.95 per BOE	
Taxes other than on income	$31 million to $35 million	
Exploration expense	$5 million to $9 million	
Interest expense [(b)]	$81 million to $85 million	
Cash Interest [(b)]	$52 million to $56 million	
Income tax expense rate	0%	
Cash tax rate	0%	
	On Income	On Cash

Pre-tax First Quarter Price Sensitivities		
$1 change in Brent index - Oil (at price above $56.00) (c)	$3.5 million	$3.5 million
$1 change in Brent index - NGLs	$0.8 million	$0.8 million
$0.50 change in NYMEX - Gas	$3.2 million	$3.2 million
First Quarter Volumes Sensitivities		
$1 change in the Brent index (d)	200 Bbl/d	

(a) Realizations exclude hedge effects.

(b) 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.

(c) At a Brent index price between $49.00 and $56.00 the sensitivity goes up to $4.4 million.

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

Attachment 10

FULL YEAR DRILLING ACTIVITY

Wells Drilled (Net)	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Development Wells					
Primary	—	—	—	—	—
Waterflood	3	5	—	—	8
Steamflood	34	—	—	—	34
Unconventional	—	—	—	—	—
Total	37	5	—	—	42
Exploration Wells					
Primary	—	—	—	—	—
Waterflood	—	—	—	—	—
Steamflood	—	—	—	—	—
Unconventional	—	—	—	—	—
Total	—	—	—	—	—
Total Wells	37	5	—	—	42
Development Drilling Capital ($ millions)	$7	$6	$—	$—	$13

Attachment 11

HEDGING ACTIVITY

	Q1 2017	Q2 2017	Q3 2017	Q4 2017	Q1 2018	Q2-Q4 2018
Crude Oil						
Calls:						
Barrels per day	12,100	5,000	10,000	15,000	15,600	15,000
Weighted-average price per barrel	$ 56.37	$ 55.05	$ 56.15	$ 56.12	$ 58.77	$ 58.83
Puts:						
Barrels per day	22,100	20,000	17,000	10,000		
Weighted-average price per barrel	$ 49.10	$ 50.25	$ 50.88	$ 48.00		
Swaps:						
Barrels per day	20,000	20,000	20,000	20,000		
Weighted-average price per barrel	$ 53.98	$ 53.98	$ 53.98	$ 53.98		

The second through fourth quarter 2017 crude oil swaps grant the counterparty a quarterly option to increase volumes by up to 10,000 barrels per day for that quarter at a weighted-average Brent price of $55.46. The counterparty also has an option to increase volumes by up to 5,000 barrels per day for the second half of the year at a weighted-average Brent price of $61.43.

Attachment 12

RESERVES

As of December 31, 2016	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Oil Reserves (in millions of barrels)					
Proved Developed Reserves	177	82	20	—	279
Proved Undeveloped Reserves	110	16	4	—	130
Total	287	98	24	—	409
NGLs Reserves (in millions of barrels)					
Proved Developed Reserves	42	—	2	—	44
Proved Undeveloped Reserves	11	—	—	—	11
Total	53	—	2	—	55
Natural Gas Reserves (in billions of cubic feet)					
Proved Developed Reserves	410	7	15	68	500
Proved Undeveloped Reserves	126	—	—	—	126
Total	536	7	15	68	626

Total Reserves (in millions of barrels of oil equivalent)*					
Proved Developed Reserves	287	83	25	11	406
Proved Undeveloped Reserves	142	16	4	—	162
Total	429	99	29	11	568

*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 barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2016, the average prices of Brent oil and NYMEX natural gas were $45.04 per Bbl and $2.42 per MMBtu, respectively, resulting in an oil-to-gas price ratio of approximately 19 to 1.

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