CALIFORNIA RESOURCES CORPORATION

2017 ANNUAL REPORT

FINANCIAL AND OPERATIONAL HIGHLIGHTS

Dollar amounts in millions, except per-share amounts as of and for the years ended December 31,

Financial Highlights	**2017**	**2016**	**2015**
Revenues	$ 2,006	$ 1,547	$ 2,403
(Loss) Income Before Income Taxes	$ (262)	$ 201	$ (5,476)
Net Income Attributable to Noncontrolling Interest	$ (4)	$ -	$ -
Net (Loss) Income Attributable to Common Stock	$ (266)	$ 279	$ (3,554)
Adjusted Net Loss[a]	$ (187)	$ (317)	$ (311)
Net (Loss) Income Attributable to Common Stock per Share - Basic and Diluted[b]	$ (6.26)	$ 6.76	$ (92.79)
Adjusted Net Loss per Share - Basic and Diluted[b]	$ (4.40)	$ (7.85)	$ (8.12)
Net Cash Provided by Operating Activities	$ 248	$ 130	$ 403
Capital Investments	$ 371	$ 75	$ 401
(Payments) Proceeds from Debt, Net	$ (18)	$ (73)	$ 356
Net Cash Provided (Used) by Financing Activities	$ 73	$ (69)	$ 352
Total Assets	$ 6,207	$ 6,354	$ 7,053
Long-Term Debt - Principal Amount	$ 5,306	$ 5,168	$ 6,043
Deferred Gain and Issuance Costs, Net	$ 287	$ 397	$ 491
Equity	$ (720)	$ (557)	$ (916)
Weighted-Average Shares Outstanding[b]	42.5	40.4	38.3
Year-End Shares	42.9	42.5	38.8

Operational Highlights	**2017**	**2016**	**2015**
Production:			
Oil (MBbl/d)	83	91	104
NGLs (MBbl/d)	16	16	18
Natural Gas (MMcf/d)	182	197	229
Total (MBoe/d)[c]	129	140	160
Average Realized Prices:			
Oil with hedge ($/Bbl)	$ 51.24	$ 42.01	$ 49.19
Oil without hedge ($/Bbl)	$ 51.47	$ 39.72	$ 47.15
NGLs ($/Bbl)	$ 35.76	$ 22.39	$ 19.62
Natural Gas ($/Mcf)[d]	$ 2.67	$ 2.28	$ 2.66
Reserves:			
Oil (MMBbl)	442	409	466
NGLs (MMBbl)	58	55	59
Natural Gas (Bcf)	706	626	715
Total (MMBoe)[c]	618	568	644
Organic Reserves Replacement Ratio[a]	119%	71%	140%
PV-10 of Proved Reserves[a] (in billions)	$ 4.5	$ 2.8	$ 5.1
Mineral Acreage (in thousands):			
Net Developed	703	717	736
Net Undeveloped	1,550	1,614	1,653
Total	2,253	2,331	2,389
Closing Share Price	$ 19.44	$ 21.29	$ 23.30

(a) See www.crc.com, Investor Relations for a discussion of these non-GAAP measures, including a reconcililation to the most closely related GAAP measure or information on the related calculations. (b) Share amounts presented on post-split basis. (c) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas and one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence. (d) For 2015, the average price realization of natural gas as a percentage of NYMEX includes the effect of hedges.

All statements, other than statements of historical fact, included in this report that address activities, events or developments that we believe will or may occur in the future are forward-looking statements. The words "anticipate," "believe," "continue," "could," "estimate," "expect," "goal," "intend," "likely," "may," "might," "plan," "potential," "project," "seek," "should," "target," "will" or "would" or other similar expressions identify forward-looking statements. Such statements specifically include our expectations as to our: future financial position • liquidity • cash flows • results of operations • business prospects • budgets • transactions • projects • operating costs • operations and operational results • maintenance capital requirements • reserves. Factors (but not necessarily all factors) that could cause our 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 • insufficient capital • unexpected geologic conditions • changes in business strategy • inability to replace reserves • inability to enter efficient hedges • equipment, service or labor price inflation or unavailability • limitations on necessary permits and approvals • worse-than-expected results of development or acquisitions • disruptions from accidents, mechanical failures, transportation or storage constraints, natural disasters, labor difficulties, cyber-attacks, and other catastrophic events • other risk factors as discussed in our Annual Report on Form 10-K. Forward-looking statements speak only as of the date on which made and we undertake no obligation to correct or update such statements, except as required by applicable law.

A MESSAGE TO OUR SHAREHOLDERS

Dear Shareholder,

In 2017, California Resources Corporation continued its role as the Golden State's largest producer of oil and natural gas on a gross-operated basis, with operating control over nearly half the oil and gas fields in California. Our workforce is proud to share California's values and to operate under the world's leading safety, labor, human rights and environmental standards. Throughout the year, our value-driven approach to developing our world-class assets allowed us to grow our reserves and improve our financial position.

We exited 2017 with proved reserves of 618 million barrels of oil equivalent (MMBOE), organically replacing 119% of our production despite a limited capital program. In addition, our probable and possible reserves[1] grew by 303 million barrels, a 37% increase from the prior year. We drilled 110 gross wells with internally funded capital and 119 gross wells from joint venture (JV) capital.

Financial discipline continued to be a focus and we lived within our cash flow in 2017 just as we have done every year since our inception — a rarity in the E&P sector. We generated a net loss of $266 million, adjusted EBITDAX[1] of $761 million and delivered a cash margin of 36%. Including $96 million of JV funded capital, our capital investments amounted to $371 million. Our internally funded development program of approximately $240 million is expected to deliver returns of 30%, on a fully burdened basis, over the life of the investment and an expected value creation index[1] ("VCI") of 1.7 at a flat $55 Brent price. At the same time, we delivered organic finding & development costs of $6.82 per barrel of oil equivalent, marking the third year in a row that these costs have been in the single digits with recycle ratios in excess of 2.0x. We also used our hedging program to protect our cash flow and underpin our capital investment.

Our financial position meaningfully strengthened in 2017 through a successful credit amendment and refinancing that provides us with significant liquidity and a clear runway to deliver value through 2021. Since our spin through February 2018, we have eliminated approximately $2.3 billion of net debt on a pro forma basis during one of the most challenging times in our industry's history.

CRC possesses a deep inventory of actionable projects at $65 Brent pricing that we expect will create real value for our shareholders in the years to come. To ensure we capture that potential value, we develop our capital plan by ranking all of our projects by drive mechanism on a fully burdened, full cycle cost basis. The result is nearly 750 MMBOE of net resources[1] with full cycle costs of $35 per BOE or less.

With a total capital commitment of up to $550 million, the JVs we entered into during 2017 with Benefit Street and Macquarie go a long way to accelerate the value of and de-risk our inventory of actionable projects. These JVs provide for development funding by our partners in specific areas and allow us to participate in all stages of production growth, including a meaningful portion of the initial growth wedge and a substantial increase in our participation once the JV partners achieve their targeted rates of return.

More recently, we monetized power and gas processing assets through a midstream JV with a portfolio company of Ares Management, L.P. The Ares portfolio company invested $750 million for certain common and preferred equity interests in the venture, and an Ares-led investor group purchased approximately 2.34 million shares of CRC's common stock in a private placement for an aggregate purchase price of $50 million in cash, or $21.33 per share. Approximately $297 million of proceeds were used to repay the Company's outstanding bank revolver balance. With our ongoing focus on value creation, we intend to deploy remaining proceeds to the best value alternative — whether that is reinvestment, acquisitions or additional debt reduction — to drive long-term shareholder returns.

Our focus for 2018 can be summed up in one word: EXECUTION. It will be a year dedicated to extending our track record of operational and financial discipline into a mid-cycle commodity environment ripe with upside. With our VCI investment criteria as a guiding principle, we will strategically invest to drive cash flow and margin growth. Including funds provided by our JV partners, we will begin with a $425 to $450 million program, which could potentially ramp through the year as confidence in the current commodity price environment grows.

Our 2018 capital plan will be deployed primarily on low decline crude oil development and delineation projects in our Buena Vista and Kettleman North Dome fields. Some of our largest assets, including the greater Elk Hills area, Wilmington, Huntington Beach and Kern Front, will also see investments focused on new conventional opportunities, as well as expanding waterflood and steamflood projects. Additionally, we intend to fund continued investment in our capital workovers, which have proven to be highly valuable.

At CRC, we are constantly focused on adapting our business model to best generate shareholder value given market dynamics. Our business opportunities dictate our structure, not the other way around. To that end, as we entered 2018, we redeployed our human capital in a new, flatter organizational structure to enable quicker decision-making and improved accountability. This organizational shift is designed to maximize the value of our assets from a cash margin and VCI perspective, while ensuring that teams are working collaboratively and creatively to achieve operational goals and sustain our exacting standards for health, safety and environmental protection.

In 2018, we expect to build upon our disciplined execution in a mid-cycle commodity environment to capture the upside that is imbedded in our business and deliver value to our shareholders. We intend to play to the strength of our low-capital intensity, low-decline rate resources, prudently allocating capital investments to the best value alternative as we deliver much-needed energy for California by Californians.

Regards,

Todd A. Stevens
President and Chief Executive Officer
California Resources Corporation

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1 See the Investor Relations page at www.crc.com for explanations of how CRC calculates and uses the non–GAAP measure of adjusted EBITDAX and a reconciliation to its nearest GAAP measure, and for other important information about possible and probable reserves and other hydrocarbon resource quantities, finding and development costs, recycle ratio calculations and drilling locations. The Value Creation Index (VCI) metric 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% discount rate. Facility costs and other non-return capital are apportioned to producing wells in the year they are drilled.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2017

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number 001-36478

California Resources Corporation

(Exact name of registrant as specified in its charter)

Delaware	**46-5670947**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
9200 Oakdale Ave. Los Angeles, California	**91311**
(Address of principal executive offices)	(Zip Code)

(888) 848-4754
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act: Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Date File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or such shorter period as the registrant was required to submit and post files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	☐	Accelerated Filer	☑	Non-Accelerated Filer	☐
Smaller Reporting Company	☐	Emerging Growth Company	☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act) Yes ☐ No ☑

The aggregate market value of the voting common stock held by nonaffiliates of the registrant was approximately $363 million, computed by reference to the closing price on the New York Stock Exchange composite tape of $8.55 per share of Common Stock on June 30, 2017. Shares of Common Stock held by each executive officer and director have been excluded from this computation in that such persons may be deemed to be affiliates. This determination of potential affiliate status is not a conclusive determination for other purposes.

At January 31, 2018, there were 42,901,946 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement to be filed with the Securities and Exchange Commission in connection with the registrant's 2018 Annual Meeting of Stockholders, are incorporated by reference into Part III of this Form 10-K.

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PART I

Item 1 BUSINESS

General

We are an independent oil and natural gas exploration and production company operating properties within California. We are the largest oil and gas producer in California on a gross operated basis and we believe we have the largest privately held mineral acreage position in the state, consisting of approximately 2.3 million net mineral acres spanning the state's four major oil and gas basins. We produced approximately 129 thousand barrels of oil equivalent per day (MBoe/d) for the year ended December 31, 2017. As of December 31, 2017, we had net proved reserves of 618 million barrels of oil equivalent (MMBoe), of which approximately 71% was categorized as proved developed reserves. Oil represented 72% of our proved reserves. We were formed in April 2014 and listed on the New York Stock Exchange on December 1, 2014. All references to ''CRC,'' the ''Company,'' ''we,'' ''us'' and ''our'' refer to California Resources Corporation and its subsidiaries.

Business Operations and Environment

Our business is focused on the production, development and exploration of conventional and unconventional oil and gas assets in California.

Our large acreage position and extensive drilling inventory provide us a diversified portfolio of oil and natural gas locations that are economically viable in a variety of operating and commodity price conditions, including many that are high-value projects throughout the price cycle. Our large fee mineral acreage position also enhances our returns because we do not make royalty and other lease payments related to these assets. Our acreage position contains numerous development and growth opportunities due to its varied geologic characteristics and multiple stacked pay reservoirs which are in many cases thousands of feet thick. We have a large portfolio of low-risk and low-decline conventional opportunities in each of our major oil and gas basins comprising approximately 71% of our proved reserves. Conventional reservoirs are capable of natural flow during primary recovery phase, often followed by waterflood and steamflood recovery methods to enhance ultimate recovery. We also have a significant portfolio of lower permeability unconventional reservoirs that typically utilize established well stimulation techniques. Our conventional and unconventional reservoirs currently include approximately 20,550 and 4,530 net identified drilling locations, respectively, primarily in the San Joaquin basin.

We are in various phases of developing many of our conventional assets and will continue to develop them using internally generated cash flow and, when appropriate, capital raised through joint ventures. Prior to the severe price declines that began in late 2014, we were focused on higher-value unconventional production from seven discrete stacked pay horizons within the Monterey formation, primarily within the upper Monterey. As commodity prices and project economics improved in 2017, we renewed our development activities in the upper Monterey and started to appraise and delineate the Kreyenhagen formation within our Kettleman North Dome field. We expect to continue pursuing unconventional opportunities in 2018 and beyond if prices remain at current levels. Over the longer term, we believe our project economics will improve, which should allow us to duplicate our successful upper Monterey results to develop opportunities in the unconventional reservoirs of the lower Monterey, Kreyenhagen and Moreno formations, which have similar geological attributes.

We have also built a 3D seismic library that covers approximately 4,820 square miles, representing over 90% of the 3D seismic data available in California. We have developed unique, proprietary stratigraphic and structural models of the subsurface geology and hydrocarbon potential in each of the four basins in which we operate. In recent years we have tested and successfully implemented various exploration, drilling, completion and enhanced recovery technologies to increase recoveries, growth and value from our portfolio. We continue working to build depth in our exploration inventory and identify new prospects based on the competitive advantage provided by this proprietary data set and our experience.

We develop our capital program by prioritizing life-of-project returns to grow our net asset value over the long term, while balancing the short- and long-term growth potential of each of our assets. We use a Value Creation Index (VCI) metric for project selection and capital allocation across our asset portfolio. We calculate the VCI for each of our projects by dividing the net present value of the project's expected pre-tax cash flow over its life by the present value of the investments, each using a 10% discount rate. Projects are expected to meet a VCI of 1.3, meaning that 30% of expected value is created above our cost of capital for every dollar invested. Our technical teams are consistently working to enhance value by improving the economics of our inventory through detailed geologic studies as well as application of more effective and efficient drilling and completion techniques. As a result, we expect many projects that do not currently meet our VCI threshold today will do so by the time of development. We regularly monitor internal performance and external factors and adjust our capital investment program with the objective of creating the most value from our asset portfolio.

With significant operating control of our properties, we have the ability to adjust our drilling and workover rig count based on commodity prices and to increase or decrease our program according to changing market conditions. We began 2017 with two drilling rigs and ended the year with nine; seven in the San Joaquin basin and one each in the Los Angeles and Ventura basins. We drilled and completed 109 net development wells with 92 wells in the San Joaquin basin, 15 in the Los Angeles basin and two in the Ventura basin. These included six primary wells, 52 steamflood wells, 31 waterflood wells, and 20 unconventional wells. We also drilled and completed five net exploration wells in the San Joaquin basin. In 2017, we increased our workover rig count from 43 at the beginning of 2017 to 59 at the end of the year to focus on projects that meet our investment criteria. In total, we performed approximately 460 capital workover projects during 2017.

The following table summarizes certain information concerning our acreage, wells and drilling locations as of December 31, 2017:

	Mineral Acreage[(a)] (in millions)		Average Net Mineral Acreage Held in Fee (%)	Producing Wells, gross	Average Net Revenue Interest (%)	Identified Drilling Locations[(b)]	
	Gross	Net				Gross	Net
San Joaquin Basin	1.7	1.5	66%	6,192	79%	25,190	17,530
Los Angeles Basin	<0.1	<0.1	46%	1,300	76%	1,950	1,930
Ventura Basin	0.3	0.2	73%	467	82%	4,310	3,900
Sacramento Basin	0.6	0.5	38%	677	75%	2,420	1,720
Total	2.7	2.3	60%	8,636	78%	33,870	25,080

(a) We currently hold approximately 38,500 gross (30,300 net) acres in the Los Angeles basin. Our Los Angeles basin operations primarily rely on dense multi-well pad drilling.

(b) Our total identified drilling locations exclude approximately 6,400 gross (5,300 net) exploration drilling locations related to unconventional reservoirs. They include approximately 2,090 gross (1,870 net) locations associated with proved undeveloped reserves and approximately 2,520 gross (2,350 net) injection well locations. Please see *Item 2—Properties—Drilling Locations* for more information regarding the processes and criteria through which we identified our drilling locations.

Compared to 2016, our 2017 production declined 8%, with only $266 million of drilling and workover capital invested for the year. This performance reflects the resilience of our asset base and the further flattening of our base production decline. In 2017, our production profile comprised roughly 64% oil, 24% natural gas and 12% natural gas liquids. Recognizing the relative value of crude oil, we are devoting the majority of our 2018 capital program to grow our oil production.

We have created a dynamic capital program for 2018 that can be adjusted to align investments with projected cash flows and joint venture (JV) funding. We believe our expanded 2018 capital program focusing primarily on low-decline crude oil assets will provide meaningful deleveraging over time while we continue to pursue additional opportunities to strengthen our balance sheet. Our capital program will also allow us to continue to delineate our high-potential conventional and unconventional areas like Buena Vista Nose and Kettleman, respectively.

We currently sell all of our crude oil into the California refining markets, which offer favorable pricing for comparable grades relative to other U.S. regions. Although California state policies actively promote and subsidize renewable energy, including solar, wind, biomass and geothermal resources, demand for oil and natural gas in California remains strong. California is heavily reliant on imported sources of energy, with approximately 72% of oil and 90% of natural gas consumed in 2017 imported from outside the state. A vast majority of the imported oil arrives via supertanker, mostly from foreign locations. As a result, California refiners have typically purchased crude oil at international waterborne-based Brent prices. We believe that the limited crude transportation infrastructure from other parts of the U.S. and California refiners' preference to run on heavy grades of oil found in California will continue contributing to favorable prices and realizations compared to other U.S. markets. During the second half of 2017, Brent crude prices began to recover, rising above $65 per barrel and reaching the highest level since 2015 as the premium of Brent over West Texas Intermediate (WTI) widened with the Organization of the Petroleum Exporting Countries (OPEC) production cuts. Additionally, our differentials improved against Brent during 2017 as a result of an increase in the official selling price to North America from the Middle East and higher-than-expected demand in Asia.

During 2017, as oil prices and activity increased, the energy industry in certain parts of the country started experiencing increases in service costs. However, the California energy industry experienced only limited cost inflation due to excess capacity in the service and supply sector. At current commodity price levels, we expect this trend to continue in 2018.

Recent Developments

In February 2018, we entered into a midstream JV with ECR Corporate Holdings L.P. (ECR), a portfolio company of Ares Management L.P. (Ares). This JV (Ares JV) holds the Elk Hills' power plant, a 550 MW natural gas fired power plant, and a 200 million cubic foot per day cryogenic gas processing plant. For more on the Ares JV, see *Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Joint Ventures*.

Our Business Strategy

We plan to drive long-term stockholder value by applying modern technologies to develop our resource base and increase production. We have significant conventional opportunities to pursue, which we develop through their life cycles to increase recovery factors by transitioning them from primary production to waterfloods, steamfloods and other enhanced recovery mechanisms.

In a sustained higher price environment, we intend to direct additional available capital to projects that provide high-value returns. A higher sustained price environment also gives us the opportunity to acquire assets that would be complementary to our existing operations. The principal elements of our business strategy include the following:

- ***Focus on high-value projects.*** In the near term, we anticipate directing the majority of our capital investments toward oil-weighted opportunities to the extent the oil-to-gas price relationship remains favorable. As a result, we expect the percentage of our oil production to continue to increase over time and favorably impact our overall margins. In 2018, approximately 95% of our identified drilling inventory is associated with oil projects. Currently, 64% of our production is oil compared to 72% of our proved reserves. Over time, we expect our share of oil production to approach the share of oil reserves.

Over the longer term, we believe we can generate significant production growth from unconventional reservoirs such as tight sandstones and shales. We hold mineral interests in approximately 1.3 million net mineral acres with unconventional potential and have identified approximately 4,930 gross (4,530 net) drilling locations on this acreage. A meaningful portion of our production already comes from unconventional assets. While we have not yet developed sufficient information to reliably predict success rates across our entire portfolio, our continued technical reviews of these projects are allowing us to better understand performance of these reservoirs in addition to improving our overall cycle time from project identification to development. As a result, we believe we will be able to direct future available capital more precisely to higher value projects, allowing us to strategically increase our investment levels in unconventional drilling over time.

- ***Maintain an appropriate share of conventional projects in our production mix to manage production declines and base maintenance capital requirements.*** Our portfolio of assets includes a large number of steamflood and waterflood projects that have much lower decline rates than many unconventional projects. We intend to focus a significant portion of our capital investments on such projects, which we expect will maintain our low production decline rates. We have approximately 28,940 gross (20,550 net) identified drilling locations associated with lower-risk conventional opportunities, 56% of which are Improved Oil Recovery (IOR) and Enhanced Oil Recovery (EOR) projects. The remaining 44% are associated with primary recovery methods, many of which we expect will develop into IOR and EOR projects in the future.

- ***Enhance stockholder value by pursuing upstream and midstream joint venture opportunities including exploration ventures.*** We believe both upstream and midstream joint ventures will enhance value by giving us the ability to significantly accelerate the development of our high-value portfolio of assets. We have already announced a number of joint ventures that have given us substantial development resources and will continue to evaluate similar opportunities in the future. We have entered into a number of exploration joint ventures, which, if successful, could result in significant long-term production growth.

- ***Increase natural gas production over time to provide clean energy to California.*** We are the largest producer of natural gas in California through our operations in the Sacramento basin. Our portfolio has a large number of mature gas fields that can be targeted for further development, with growth opportunities in under-developed areas of our asset base, including significant growth potential in the Sacramento basin. We are focused on developing technologies and execution approaches that will generate commercial projects at current price levels while maintaining a targeted exploration program for new resources. In addition, we expect to pursue strategic joint ventures to unlock the value of our asset portfolio.

- ***Maintain a proactive and collaborative approach to safety, environmental protection and community outreach, while helping the state address its energy and water needs.*** We are committed to managing our assets in a manner that safeguards people and protects the environment, and to reducing California's dependence on imported energy. We proactively engage with regulatory agencies, communities, organized labor and other stakeholders to pursue mutually beneficial outcomes that supply affordable and reliable energy from local sources and that expand opportunities for the communities in which we live and work. As a California company, helping our state meet its water needs is a key priority. We are a net water supplier to agriculture due to our dedicated team and investments in water conservation and the recycling of produced water from oil and gas reservoirs. In 2017, our operations supplied 4.9 billion gallons of reclaimed water for agricultural use, a new company record that far exceeds the volume of fresh water we purchased for our operations statewide.

- ***Apply proven modern development and production methods to enhance production growth and cost efficiency.*** Over the last several decades, the oil and gas industry has focused significantly less effort on utilizing modern development and exploration processes and technologies in California relative to other prolific U.S. basins. We believe this is largely due to other oil companies' limited capital investments in California, concentration on shallow-zone thermal projects and investments in other assets within their global portfolios. As an independent company focused on California, we use proven modern technologies in drilling and completing wells, as well as production methods that we expect will substantially increase both our production and cost efficiency over time. We have developed an extensive 3D seismic library covering almost 4,820 square miles in all four of our basins, representing over 90% of the 3D seismic data available for California, and have tested and successfully implemented various exploration, drilling, completion, IOR and EOR technologies in the state.

- ***Utilize advanced technologies to improve our operations**.* We have a dedicated Big Data Analytics team focused on analyzing data to help us make better operating and development decisions that enhance the value of our assets. We are evaluating advanced technologies such as artificial intelligence, machine learning, algorithms, complex math analysis and other digital solutions to predictively optimize our business processes, development criteria and our drilling and production techniques.

Key Characteristics of our Operations

The following are among the key characteristics of our operations:

- ***Operational control of our diverse asset base provides flexibility during commodity price cycles and preserves future value and growth potential.*** Our near 100% operational control of 135 fields in California provides us flexibility to adapt our investments to various market environments through our ability to select drilling locations, the timing of our development and the drilling and completion techniques we use. Our large and diverse mineral acreage position allows us to choose to develop conventional or unconventional reservoirs of either oil or natural gas using multiple recovery mechanisms, such as primary, steamflood and waterflood. In addition, approximately 60% of our acreage position is held in fee and 15% is held by production, which gives us flexibility to choose the timing of our development projects. A majority of our interests are in producing properties located in reservoirs characterized by what we believe have long-lived production profiles with repeatable development opportunities. Approximately 95% of our identified drilling inventory is associated with oil-rich projects, primarily located in the San Joaquin, Los Angeles and Ventura basins, and the remaining inventory is associated with natural gas properties in the Sacramento, San Joaquin and Ventura basins. The variety of recovery mechanisms and product types available to us, together with our operating control, allows us to allocate capital in a manner designed to optimize cash flow over a wide range of commodity prices. The low base decline of our conventional assets allows us to limit production declines with minimal investment, positioning us to achieve oil-production growth in the current price environment while living within our means.

- ***Largest acreage position in a world-class oil and natural gas province.*** We believe we are the largest private oil and natural gas mineral acreage holder in California, with interests in approximately 2.3 million net mineral acres. California is one of the most prolific oil and natural gas producing regions in the world. California is also the nation's largest state economy, and the world's sixth largest, with significant energy demands that exceed local supply. Our large acreage position with a diverse development portfolio enables us to pursue the appropriate production strategy for the relevant commodity price environment without the need to acquire new acreage. For example, in a high natural gas price environment we can rapidly increase our investments in the Sacramento basin to generate significant production growth. Our large acreage position also allows us to quickly deploy the knowledge we gain in our existing operations, together with our seismic data, in other areas within our portfolio.

- ***Opportunity rich drilling and workover portfolio.*** Our drilling inventory at December 31, 2017 consisted of approximately 33,870 gross (25,080 net) identified well locations, including approximately 28,940 gross (20,550 net) conventional drilling locations and approximately 4,930 gross (4,530 net) unconventional drilling locations. Our drilling inventory count increased by about 10% from the prior year as a result of our technical teams' continued efforts. We also have approximately 1,200 workover projects that can deliver high returns. At about $65 Brent, we estimate we have increased the investment opportunities for drilling and workover capital that meet our 1.3 VCI threshold by 20%. In the process, our inventory of lower-risk conventional development opportunities with attractive returns has increased even more than our unconventional opportunities. In a sustained favorable oil and gas price environment, we believe we can also achieve further long-term production growth through the development of unconventional reservoirs. In addition, our rich conventional and unconventional portfolio can provide attractive JV opportunities.

- ***Proven operational management and technical teams with extensive experience operating in California.*** The members of our operational management and technical teams have an average of over 25 years of experience in the oil and natural gas industry, with an average of over 15 years focused on our California oil and gas operations through different price cycles. Our teams have a proven track record of applying modern technologies and operating methods to develop our assets and improve their operating efficiencies. For example, we have successfully reduced field operating costs by approximately 27% since 2014.

Portfolio Management and Capital Program

We develop our capital program by prioritizing projects that have returns that will grow our net asset value over the long term, while balancing the short- and long-term growth potential of each of our assets. We use the VCI metric for project selection and capital allocation across our asset portfolio. Typically, we create the highest value by reinvesting our cash flow back into our business, including attractive acquisitions. Our low decline rates compared to our industry peers together with our high level of operational control give us the flexibility to adjust the level of such capital investments as circumstances warrant.

2017 Capital Program

Our 2017 capital program predominantly targeted projects in the San Joaquin and Los Angeles basins, and virtually all of our capital was directed towards oil-weighted production, consistent with 2016 and 2015. The program was initially set at approximately $300 million but increased to $371 million when we entered into JVs with Benefit Street Partners (BSP) and Macquarie Infrastructure and Real Assets Inc. (MIRA). Our $371 million capital program included $96 million of funding from

BSP and excluded $58 million of funding from MIRA, which is not reported in our consolidated results. Excluding MIRA capital, we invested approximately $177 million for drilling wells, $89 million for capital workovers, $71 million for facilities and compression expansion, $25 million for maintenance and occupational health, safety and environmental projects and $9 million for exploration and other items. We ended 2017 with nine rigs running and anticipate our activity levels to remain at an average nine-rig pace for the first quarter of 2018.

2018 Capital Program

We are focusing our 2018 capital on oil projects, which provide higher margins and low decline rates that we believe will generate cash flow to fund increasing capital budgets that will grow production. Our approach to our 2018 drilling program is consistent with our stated strategy to remain financially disciplined and fund projects through either internally generated cash flow or JV capital to maintain our liquidity and further strengthen our balance sheet. We continue to deploy our partners' capital as part of our BSP and MIRA joint ventures and opportunistically pursue additional strategic relationships. We will deploy capital to projects that help continue to stabilize our production, develop our long-term resources and return our production to a growth profile. We will continue to focus on our core fields: Elk Hills, Wilmington, Kern Front and the delineation and appraisal of Kettleman North Dome and Buena Vista. We will also restart our development activities in the Huntington Beach field.

With stronger expected cash flow, we estimate our 2018 capital program will range from $425 million to $450 million, which includes approximately $100 to $150 million in JV capital. Our 2018 capital program may grow further through additional tranches from existing JVs as well as potential new JVs.

Our current drilling inventory comprises a diversified portfolio of oil and natural gas locations that are economically viable in a variety of operating and commodity price conditions. Our 2018 drilling program includes development of conventional and unconventional resources. The depth of our primary conventional wells is expected to range from 2,000 to 15,000 feet. With a significant reduction in our drilling costs since 2014, many of our deep conventional and unconventional wells have become more competitive, and we expect to use approximately 60% of our capital on drilling. We expect to focus our conventional program of approximately 130 wells primarily in Wilmington, Huntington Beach, Kern Front, Pleito Ranch and Mount Poso, which will largely consist of waterfloods and steamfloods along with some primary drilling. We intend to drill approximately 20 unconventional wells in the Buena Vista and Kettleman areas.

We also plan to use over 20% of our 2018 capital program for capital workovers on existing well bores. Capital workovers are some of the highest VCI projects in our portfolio and generally include well deepenings, recompletions, changes of lift methods and other activities designed to add incremental productive intervals and reserves.

Further, over 15% of our 2018 capital program is intended for development facilities for our projects, including pipeline and gathering line interconnections, gas compression and water management systems, and about 5% is intended to be used for exploration and to maintain the mechanical integrity, safety and environmental performance of our operations.

Reserves and Production Information

The table below summarizes our proved reserves and average net daily production as of and for the year ended December 31, 2017 in each of California's four major oil and gas basins:

	Proved Reserves as of December 31, 2017						Average Net Daily Production for the Year Ended December 31, 2017		
	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBoe)	Oil (%)	Proved Developed (%)	(MBoe/d)	Oil (%)	R/P Ratio (Years)[(a)]
San Joaquin Basin	265	56	585	419	63%	70%	90	58%	12.8
Los Angeles Basin	143	—	10	145	99%	72%	27	100%	14.7
Ventura Basin	34	2	26	40	85%	73%	6	67%	18.3
Sacramento Basin	—	—	85	14	—	86%	6	—%	6.4
Total operations	442	58	706	618	72%	71%	129	64%	13.1

Note: MMBbl refers to millions of barrels; Bcf refers to billion cubic feet of natural gas; MMBoe refers to million barrels of oil equivalent; and MBoe/d refers to thousands of barrels of oil equivalent per day. 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.

(a) Calculated as total proved reserves as of December 31, 2017 divided by annualized Average Net Daily Production for the year ended December 31, 2017.

Marketing Arrangements

Crude Oil—Substantially all of our crude oil production is connected to California markets via our crude oil gathering pipelines, which are used almost entirely for our production. We generally do not transport, refine or process the crude oil we produce and do not have any significant long-term crude oil transportation arrangements. We currently sell all of our crude oil into the California refining markets, which we believe have offered relatively favorable pricing compared to other U.S. regions for similar grades. In addition, we evaluate opportunities to export our crude oil production. The majority of the oil imported into California arrives via supertanker, with a minor amount arriving by rail. As a result, California refiners have typically purchased crude oil at international waterborne-based prices. Currently, our index-based crude oil sales contracts have 30- to 90-day terms with no such contracts extending past one year.

Natural Gas—California imports approximately 90% of the natural gas consumed in the state. We have firm transportation capacity contracts to access markets and to facilitate deliveries. We sell virtually all of our natural gas production under individually negotiated contracts using market-based pricing on a monthly or shorter basis.

NGLs—We extract substantially all of our NGLs through our gas processing plants, which facilitate access to third-party delivery points near the Elk Hills field. We currently have pipeline capacity contracts to transport 20,000 barrels per day of NGLs to market. We sell virtually all of our NGLs using index-based pricing. Our NGLs are generally sold pursuant to one-year contracts that are renewed annually. Approximately 36% of our NGLs are sold to export markets.

Electricity—Part of the electrical output of the Elk Hills power plant operated by one of our subsidiaries is used by the Elk Hills field, which reduces operating costs and increases reliability. We sell the excess to the grid and to utilities.

Hedging

We maintain a commodity hedging program primarily focused on crude oil to help protect our cash flows, margins and capital program from the volatility of commodity prices and to improve our ability to comply with the covenants under our credit facilities. We will continue to be strategic and opportunistic in implementing our hedging program. Unless otherwise indicated, we use the term “hedge” to describe derivative instruments that are designed to achieve our hedging program goals, even though they are not necessarily accounted for as cash-flow or fair-value hedges. For more on our current derivative contracts, see *Item 7—Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources*.

Our Principal Customers

We sell crude oil, natural gas and NGLs to marketers, California refineries and other purchasers that have access to transportation and storage facilities. Our ability to sell our products can be affected by factors that are beyond our control, and which cannot be accurately predicted.

For the years ended December 31, 2017 and 2016, our principal customers included Phillips 66 Company, Andeavor (formerly Tesoro Refining & Marketing Company LLC), Valero Marketing & Supply Company and Shell Trading (US) Company, each accounted for at least 10%, and, collectively, 67% of our revenue. For the year ended December 31, 2015, our principal customers included Phillips 66 Company, Tesoro Refining & Marketing Company LLC and Valero Marketing & Supply Company, each accounted for more than 10%, and collectively, 64% of our revenue.

Title to Properties

As is customary in the oil and natural gas industry for acquired properties, we initially conduct a high-level review of the title to our properties at the time of acquisition. Individual properties may be subject to ordinary course burdens that we believe do not materially interfere with the use or affect the value of such properties. Burdens on properties may include customary royalty interests, liens incident to operating agreements and for current taxes, obligations or duties under applicable laws, development obligations, or net profits interests, among others. Prior to the commencement of drilling operations on those properties, we conduct a more thorough title examination and perform curative work with respect to significant defects. We generally will not commence drilling operations on a property until we have cured known title defects that are material to the project. In addition, substantially all of our properties have been pledged as collateral for our secured debt.

Competition

We encounter strong competition from numerous parties in the oil and gas industry, ranging from small independent producers to major international oil companies. The oil market in California is a captive market with no interstate crude pipeline and rail lines that only run north to south. As a result, 72% of the oil the state consumes is imported, virtually all from waterborne sources. Our proximity to the California refineries gives us a competitive edge through lower transportation costs. The California natural gas market is serviced from a network of pipelines, including interstate and intrastate pipelines. We deliver our natural gas to customers using capacity on our firm transportation commitments.

We compete for third-party services to profitably develop our assets, to find or acquire additional reserves, to sell our production and to find and retain qualified personnel. Historically, higher commodity prices intensify competition for drilling and workover rigs, pipe, other oil field equipment and personnel. However, the California energy industry experienced only limited cost inflation in 2017 due to excess capacity in the service and supply sector. Given our relative size compared to other in-state producers, our activity influences the pricing of third-party services in the local market.

Regulation of the Oil and Natural Gas Industry

Our operations are subject to a wide range of federal, state and local laws and regulations. Those that specifically relate to oil and natural gas exploration and production are described in this section.

Regulation of Exploration and Production

Federal, state and local laws and regulations govern most aspects of exploration and production in California, including:

- oil and natural gas production, including well spacing on federal, state and private lands;
- methods of constructing, drilling, completing, stimulating, operating, maintaining and abandoning wells;
- the design, construction, operation, maintenance and decommissioning of facilities, such as natural gas processing plants, power plants, compressors and liquid and natural gas pipelines or gathering lines;
- improved or enhanced recovery techniques such as fluid injection for pressure management, waterflooding or steamflooding;
- sourcing and disposal of water used in the drilling, completion, stimulation, maintenance and enhanced recovery processes;
- imposition of taxes and fees with respect to our properties and operations;
- the conservation of oil and natural gas, including provisions for the unitization or pooling of oil and natural gas properties;
- posting of bonds or other financial assurance to drill, operate and abandon or decommission wells and facilities; and
- occupational health, safety and environmental matters and the transportation, marketing and sale of our products as described below.

Collectively, the effect of these regulations is to potentially limit the number and location of our wells and the amount of oil and natural gas that we can produce from our wells compared to what we otherwise would be able to do.

The Division of Oil, Gas, and Geothermal Resources (DOGGR) of the Department of Conservation is California's primary regulator of the oil and natural gas industry on private and state lands, with additional oversight from the State Lands Commission's administration of state surface and mineral interests. The Bureau of Land Management (BLM) of the U.S. Department of the Interior exercises similar jurisdiction on federal lands in California, on which DOGGR also asserts jurisdiction over certain activities. Government actions, including the issuance of certain permits or approvals, by state and local agencies or by federal agencies may be subject to environmental reviews, respectively, under the California Environmental Quality Act or the National Environmental Policy Act (NEPA), which may result in delays, imposition of mitigation measures or litigation. For example, in September 2016, a federal judge issued an order finding that the BLM's NEPA review of the Resource Management Plan for portions of Ventura, Kern and other counties failed to sufficiently analyze the potential environmental impacts of hydraulic fracturing and directed the BLM to prepare a supplemental environmental impact statement. The result of this NEPA review has the potential to impact future leasing of federal lands in those counties for oil and gas exploration and production activities.

The jurisdiction and enforcement authority of DOGGR and other state agencies have significantly increased with respect to oil and gas activities in recent years, and these agencies have significantly revised their regulations, regulatory interpretations and data collection requirements. DOGGR has undertaken a comprehensive examination of existing regulations and plans to issue additional regulations with respect to certain oil and gas activities in 2018, such as management of idle wells, pipelines and underground fluid injection. Pursuant to Assembly Bill 2729 (AB 2729), DOGGR requires operators annually starting in 2018 to either submit idle well management plans describing how they will plug and abandon or reactivate long-term idle wells or pay additional annual fees for each such well. AB 2729 also requires that DOGGR update its regulations pertaining to idle well testing and management by June 1, 2018. In September 2017, DOGGR proposed regulations that seek to impose more stringent inspection and integrity management requirements on pipelines that are four inches or less in diameter and located in sensitive areas. DOGGR’s plan to update underground injection regulations in 2018, which may address injection approvals, project data requirements, mechanical integrity testing of injection wells, monitoring and reporting requirements with respect to injection parameters, containment or seismic activity, and incident response.

In 2013 California adopted Senate Bill 4 (SB 4), which increased regulation of certain well stimulation techniques, including acid matrix stimulation and hydraulic fracturing, which involves the injection of fluid under pressure into underground rock formations to create or enlarge fractures to allow oil and gas to flow more freely. Among other things, SB 4 requires operators to obtain specific well stimulation permits, make disclosures and implement groundwater monitoring and water management plans. The U.S. Environmental Protection Agency (EPA) and the BLM also regulate certain well stimulation activities, though their regulations are currently being challenged in court. The implementation of federal and state well stimulation regulations has delayed, and increased the cost of, certain operations.

In addition, certain local governments have proposed or adopted ordinances that would restrict certain drilling activities in general and well stimulation, completion or injection activities in particular, or ban such activities outright. The most onerous of these local measures was adopted in 2016 by Monterey County, where we own mineral interests but do not have any production. The measure prohibits drilling of new oil and gas wells, hydraulic fracturing, other well stimulation and phases out the injection of produced water. This measure was challenged in state court, and the Monterey County Superior Court issued a decision in December 2017, finding that the bans on drilling new wells and water injection are preempted and invalid by existing state and federal regulations and, if implemented, would constitute a taking of our property without compensation under the federal and state constitutions. The court did not rule on the ban on hydraulic fracturing because the court found that the issue was not ripe since hydraulic fracturing is not currently being conducted in Monterey County, noting that the ban could be challenged in the event a hydraulic fracturing is proposed. The decision is expected to be appealed.

Regulation of Health, Safety and Environmental Matters

Numerous federal, state, local, and other laws and regulations that govern health and safety, the release or discharge of materials, land use or environmental protection may restrict the use of our properties and operations, increase our costs or lower demand for or restrict the use of our products and services. Applicable federal health, safety and environmental laws include the Occupational Safety and Health Act, Clean Air Act, Clean Water Act, Safe Drinking Water Act, Oil Pollution Act, Natural Gas Pipeline Safety Act, Pipeline Safety Improvement Act, Pipeline Safety, Regulatory Certainty, and Job Creation Act, Endangered Species Act, Migratory Bird Treaty Act, Comprehensive Environmental Response, Compensation, and Liability Act, Resource Conservation and Recovery Act and National Environmental Policy Act, among others. California imposes additional laws that are analogous to, and often more stringent than, such federal laws. These laws and regulations:

- establish air, soil and water quality standards for a given region, such as the San Joaquin Valley, and require attainment plans to meet those regional standards, which may include significant restrictions on development, economic activity and transportation in such region;
- require various permits, approvals and mitigation measures before drilling, workover, production, underground fluid injection or waste disposal commences, or before facilities are constructed or put into operation;
- require the installation of sophisticated safety and pollution control equipment, such as leak detection, monitoring and shutdown systems, to prevent or reduce releases or discharges of regulated materials to air, land, surface water or ground water;

- restrict the use, types or sources of water, energy, land surface, habitat or other natural resources, require conservation and reclamation measures, and impose energy efficiency or renewable energy standards on us or users of our products and services;
- restrict the types, quantities and concentrations of regulated materials, including oil, natural gas, produced water or wastes, that can be released or discharged into the environment, or any other uses of those materials resulting from drilling, production, processing, power generation, transportation or storage activities;
- limit or prohibit operations on lands lying within coastal, wilderness, wetlands, groundwater recharge, endangered species habitat and other protected areas, and require the dedication of surface acreage for habitat conservation;
- establish standards for the management of solid and hazardous wastes or the closure, abandonment, cleanup or restoration of former operations, such as plugging and abandonment of wells and decommissioning of facilities;
- impose substantial liabilities for unauthorized releases or discharges of regulated materials into the environment with respect to our current or former properties and operations and other locations where such materials generated by us or our predecessors were released or discharged;
- require comprehensive environmental analyses, recordkeeping and reports with respect to operations affecting federal, state and private lands or leases;
- impose taxes or fees with respect to the foregoing matters;
- may expose us to litigation with government authorities, counterparties, special interest groups or others; and
- may restrict our rate of oil, NGLs, natural gas and electricity production.

Due to the severe drought in California over the last several years, water districts and the state government have implemented regulations and policies that may restrict groundwater extraction and water usage and increase the cost of water. Water management is an essential component of our operations. We treat and reuse water that is co-produced with oil and natural gas for a substantial portion of our needs in activities such as pressure management, waterflooding, steamflooding and well drilling, completion and stimulation. We also provide reclaimed produced water to certain agricultural water districts. We also use supplied water from various local and regional sources, particularly for power plants and to support operations like steam injection in certain fields.

In 2014, at the request of the EPA, DOGGR commenced a detailed review of the multi-decade practice of permitting underground injection wells and associated aquifer exemptions under the Safe Drinking Water Act (SDWA). In 2015, the state set deadlines to obtain the EPA's confirmation of aquifer exemptions under the SDWA in certain formations in certain fields. Since the state and the EPA did not complete their review before the state's deadlines, the state announced that it will not rescind permits or enforce the deadlines with respect to many of the formations pending completion of the review, but has applied the deadlines to others. During the review, the state has restricted injection in certain formations or wells in several fields, including some operated by us, requested that we change injection zones in certain fields, and held certain pending injection permits in abeyance. Several industry groups and operators challenged DOGGR's implementation of its aquifer exemption regulations. In March 2017, the Kern County Superior Court issued an injunction barring the blanket enforcement of DOGGR's aquifer exemption regulations. The court found that DOGGR must find actual harm results from an injection well's operations and go through a hearing process before the agency can issue fines or shut down operations.

Separately, the state began a review in 2015 of permitted surface discharge of produced water and the use of reclaimed water for agricultural irrigation, which has led to additional permitting and monitoring requirements in 2017 for surface discharge of produced water. To date, the foregoing regulatory actions have not affected our oil and natural gas production in a material way. These reviews are ongoing, and government authorities may ultimately restrict injection of produced water or other fluids in additional formations or certain wells, restrict the surface discharge or use of produced water or take other administrative actions. The foregoing reviews could also give rise to litigation with government authorities and third parties.

Federal, state and local agencies may assert overlapping authority to regulate in these areas. In addition, certain of these laws and regulations may apply retroactively and may impose strict or joint and several liability on us for events or conditions over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

Regulation of Climate Change and Greenhouse Gas (GHG) Emissions

A number of international, federal, state, regional and local efforts seek to prevent or mitigate the effects of climate change or to track and reduce GHG emissions associated with energy use and industrial activity, including operations of the oil and natural gas production sector and those who use our products as a source of energy. The EPA has adopted federal regulations to:

- require reporting of annual GHG emissions from power plants and gas processing plants; gathering and boosting compression and pipeline facilities; and certain completions and workovers;
- incorporate measures to reduce GHG emissions in permits for certain facilities; and
- restrict GHG emissions from certain mobile sources.

California has adopted the most stringent such laws and regulations. These state laws and regulations:

- established a “cap-and-trade” program for GHG emissions that sets a statewide maximum limit on covered GHG emissions, and this cap declines annually to reach 40% below 1990 levels by 2030, the year that the cap-and-trade program currently expires;
- require allowances or qualifying offsets for GHGs emitted from California operations and for the volume of propane and liquid transportation fuels sold for use in California;
- established a low carbon fuel standard, which requires the use of fuels with lower carbon intensities than traditional gasoline and diesel fuels;
- impose state goals to derive 50% of California’s electricity from renewable sources and to double the energy efficiency of buildings in the state by 2030; and
- impose state goals of reducing emissions of methane and fluorocarbon gases by 40% and black carbon by 50% below 2013 levels by 2030.

The EPA and the California Air Resources Board (CARB) have also expanded direct regulation of methane as a contributor to greenhouse gas emissions. In 2016, the EPA adopted regulations to require additional emission controls for methane, volatile organic compounds and certain other substances for new or modified oil and natural gas facilities. Although the EPA proposed in June 2017 to stay its 2016 methane requirements for two years and revisit their implementation, CARB has adopted more stringent regulations to require monitoring, leak detection, repair and reporting of methane emissions from both existing and new oil and gas production, pipeline gathering and boosting facilities and natural gas processing plants beginning in 2018 and additional controls such as tank vapor recovery to capture methane emissions in subsequent years.

Legislation and regulation to address climate change could also increase the cost of consuming, and thereby reduce demand for, oil, natural gas and other products produced by us, and potentially lower the value of our reserves and other assets.

Regulation of Transportation, Marketing and Sale of Our Products

Our sales prices of oil, NGLs and natural gas in the U.S. are set by the market and are not presently regulated. In late 2015, the U.S. federal government lifted restrictions on the export of domestically produced oil that allows for the sale of U.S. oil production, including ours, in additional markets, which may affect the prices we realize.

Federal and state laws regulate transportation rates for, and marketing and sale of, petroleum products and electricity with respect to certain of our operations and those of certain of our customers, suppliers and counterparties. Such regulations also govern:

- interstate and intrastate pipeline transportation rates for oil, natural gas and NGLs in regulated pipeline systems;
- prevention of market manipulation in the oil, natural gas, NGL and power markets;
- market transparency rules with respect to natural gas and power markets;
- the physical and futures energy commodities market, including financial derivative and hedging activity; and
- prevention of discrimination in natural gas gathering operations in favor of producers or sources of supply.

The federal and state agencies overseeing these regulations have substantial rate-setting and enforcement authority, and violation of the foregoing regulations could expose us to litigation with government authorities, counterparties, special interest groups and others.

Employees

We had approximately 1,450 employees as of December 31, 2017, of whom approximately 1,070 were employed in field operations. Approximately 70 of our employees are represented by labor unions. We have not experienced any strikes or work stoppages by our employees since our formation in 2014. We also utilize the services of independent contractors to perform drilling, well work, operations, construction and other services, including construction contractors whose workforce is often represented by labor unions.

Spin-Off and Reverse Stock Split

We were incorporated in Delaware as a wholly owned subsidiary of Occidental on April 23, 2014, and remained a wholly owned subsidiary of Occidental until November 30, 2014 when Occidental distributed shares of our common stock on a pro-rata basis to Occidental stockholders (the Spin-off). On December 1, 2014, we became an independent, publicly traded company. Occidental initially retained approximately 18.5% of our outstanding shares of common stock, which were distributed to its stockholders on March 24, 2016. All references to ''Occidental'' refer to Occidental Petroleum Corporation, our former parent, and its subsidiaries.

On May 31, 2016 we completed a reverse stock split using a ratio of one share of common stock for every ten shares then outstanding. Share and per share amounts included in this report have been restated to reflect this reverse stock split.

Available Information

We make the following information available free of charge on our website at www.crc.com:

- Forms 10-K, 10-Q, 8-K and amendments to these forms as soon as reasonably practicable after they are electronically filed with, or furnished to, the Securities and Exchange Commission (SEC);
- Other SEC filings including Forms 3, 4 and 5;
- Corporate governance information, including our corporate governance guidelines, board-committee charters and code of business conduct (see *Item 10—Directors, Executive Officers and Corporate Governance* for further information); and
- Other important additional information, including GAAP to non-GAAP reconciliations.

Information contained on our website is not part of this report.

ITEM 1A RISK FACTORS

RISK FACTORS

We are subject to certain risks and hazards due to the nature of our business activities. The risks discussed below, any of which could materially and adversely affect our business, financial condition, cash flows and results of operations, are not the only risks we face. We may experience additional risks and uncertainties not currently known to us or, as a result of developments occurring in the future, conditions that we currently deem to be immaterial may ultimately materially and adversely affect our business, financial condition, cash flows and results of operations.

Commodity pricing can fluctuate widely and strongly affects our results of operations, financial condition, cash flow and ability to invest in our assets.

Our results of operations, financial condition, cash flow and ability to invest in our assets are highly dependent on commodity prices. Compared to early to mid-2014, global energy commodity prices have declined significantly. We are particularly dependent on Brent crude prices that have declined from over $110 per barrel in June 2014 to below $30 per barrel in January 2016. Brent prices have improved since early 2016 and averaged $54.82 in 2017. However, such improvements may not continue or may be reversed. Continued low prices for our products or further price decreases could have several adverse effects including:

- reduced cash flow and decreased funds available for capital investments, interest payments and operational expenses;
- reduced proved oil and gas reserves over time and related cash flows;
- impairments of our oil and gas properties;
- reduced borrowing base capacity under our 2014 Revolving Credit Facility as proved oil and gas reserves values fall;
- the potential for a reduction of our liquidity, mandatory loan repayments and default and foreclosure by our banks and bondholders against our secured assets;
- forced monetization events and potential issues under our JV arrangements;
- inability to attract counterparties to our transactions, including hedging transactions; and
- inability to access funds through the capital markets and the price we could obtain for, or the ability to conduct, asset sales or other monetization transactions.

Commodity pricing can fluctuate widely and is affected by a variety of factors, including changes in consumption patterns; inventory levels; global and local economic conditions; the actions of OPEC and other significant producers and governments; actual or threatened production, refining and processing disruptions; worldwide drilling and exploration activities; the effects of conservation; weather, geophysical and technical limitations; currency exchange rates; technological advances; transportation and storage capacity, bottlenecks and costs in producing areas; alternative energy sources; regional market conditions; other matters affecting the supply and demand dynamics for our products; and the effect of changes in these variables on market perceptions. These and other factors make it impossible to predict realized prices reliably. While our hedging activities provide some downside protection for a significant portion of our 2018 production, they may not adequately protect us from commodity price reductions and we may be unable to enter into acceptable additional hedges.

Our lenders require us to comply with covenants and can limit our borrowing capabilities, which may materially limit our ability to use or access capital and our business activities.

Our ability to borrow funds under our 2014 Revolving Credit Facility is limited by our borrowing base, the size of our lenders' commitments, our ability to comply with covenants and a minimum monthly liquidity requirement of $150 million. Currently, the lenders' aggregate commitment under our 2014 Revolving Credit Facility is $1 billion, and we had approximately $850 million in availability, before taking into account the minimum liquidity requirement. We may need to draw on our 2014 Revolving Credit Facility for a portion of our future capital or operating needs.

The financial covenants that we must satisfy under our 2014 Revolving Credit Facility include a monthly minimum liquidity test and quarterly first-out leverage, interest expense coverage and first-lien asset coverage ratios. The 2014 Revolving Credit Facility also restricts our ability to monetize assets and issue or purchase debt. Our borrowing base under our 2014 Revolving Credit Facility is redetermined each May 1 and November 1. The borrowing base is determined with reference to a number of factors, including commodity prices and reserves. Restrictions under our 2014 Revolving Credit Facility are further described in *Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Agreements*.

If we were to breach any of the covenants under our 2014 Revolving Credit Facility, our lenders would be permitted to accelerate the principal amount due under the 2014 Revolving Credit Facility and foreclose against the assets securing them. If payment were accelerated, or we failed to make certain payments, under our 2014 Revolving Credit Facility, it would result in a default under our 2016 and 2017 Credit Agreements and outstanding notes and permit acceleration and foreclosure against the assets securing the 2016 and 2017 Credit Agreements and the Second Lien Notes.

Low commodity prices, coupled with substantial interest payments, could constrain our liquidity. A significant reduction in our liquidity may force us to take actions that could have significant adverse effects.

The primary source of liquidity and resources to fund our capital program and other obligations is cash flow from operations and borrowings under our 2014 Revolving Credit Facility. As noted above, our borrowing capacity is limited.

Further price declines would reduce our cash flows from operations and may limit our access to borrowing capacity or cause a default under our financing agreements. Under these conditions, if we were unable to achieve improved liquidity through additional financing, asset monetizations, restructuring of our debt obligations, equity issuances or otherwise, cash flow from operations and expected available credit capacity could be insufficient to meet our commitments. Successfully completing these actions could have significant adverse effects such as higher operating and financing costs, loss of certain tax benefits or dilution of equity. Past refinancing activities have resulted in increases in our annual interest expense and future refinancing activities may have the same effect.

We have significant indebtedness that could make us more vulnerable in economic downturns.

As of December 31, 2017, we had long-term consolidated indebtedness of $5.3 billion. Our financing agreements permit us to incur significant additional indebtedness as well as certain other obligations. We may seek amendments or waivers to the extent we need to incur indebtedness above amounts currently permitted by our financing agreements.

Certain of our outstanding indebtedness bears interest at variable rates and a rise in interest rates will increase our interest expense to the extent we do not purchase interest-rate hedges.

Our level of indebtedness may have several important consequences, including:

- jeopardizing our ability to execute our business plans;
- increasing our vulnerability to adverse changes in our business and in economic and industry conditions;
- putting us at a disadvantage against competitors that have lower fixed obligations and more cash flow to devote to their businesses;
- limiting our ability to obtain favorable financing for working capital, capital investments and general corporate and other purposes; and
- limiting our flexibility to operate our business, compete for capital, react to competitive pressures, and engage in certain transactions that might otherwise be beneficial to us.

Subject to certain exceptions, our financing agreements limit:

- incurring additional indebtedness;
- repaying junior indebtedness, including our Second Lien Notes and Senior Notes;
- making investments;
- entering into JVs;
- paying dividends and other restricted payments;
- creating liens on our assets;
- selling assets;
- using the proceeds of asset sales for certain purposes;
- entering into mergers or acquisitions; and
- releasing collateral.

These limitations are further described in *Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Agreement; Second Lien Notes; Senior Notes* and the documents governing our indebtedness that are filed with the Securities and Exchange Commission (SEC).

Our ability to meet our debt obligations and other financial needs will depend on our future performance, which is influenced by market, financial, business, economic, regulatory and other factors. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or issue additional equity on terms that may be unattractive, if it can be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default. Any of these factors could result in a material adverse effect on our business, financial condition, cash flows or results of operations and a default on our indebtedness could result in acceleration of all of our debt and foreclosure against assets constituting collateral for our secured credit facilities and secured notes.

Our business requires substantial capital investments, which may include acquisitions. We may be unable to fund these investments through operating cash flow or obtain any needed additional capital on satisfactory terms or at all, which could lead to a decline in our oil and gas reserves or production. Our capital investment program is also susceptible to risks that could materially affect its implementation.

The oil and gas industry is capital intensive. We make and expect to increase capital investments for the development and exploration of oil and gas reserves. Our ability to deploy capital as planned depends on a number of variables, including:

- commodity prices;
- regulatory and third-party approvals;
- our ability to timely drill, complete and stimulate wells;
- the availability of, and our ability to compete for, capital, equipment, services and personnel; and
- the availability of external sources of financing, including from JVs.

Future capital availability may be reduced by (i) our lenders, (ii) our JV partners, (iii) capital markets constraints, (iv) activist funds or investors or (v) poor stock price performance. Because of these and other potential variables, we may be unable to deploy capital in the manner planned, which may negatively impact our production decline and constrain our development or acquisition activities.

Unless we make sufficient capital investments and conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our ability to make the necessary long-term capital investments or acquisitions needed to maintain or expand our reserves may be impaired to the extent cash flow from operations or external sources of capital are insufficient. We may not be successful in developing, exploring for or acquiring additional reserves. Over the long term, a continuing decline in our production and reserves would reduce our liquidity and ability to satisfy our debt obligations by reducing our cash flow from operations and the value of our assets.

Estimates of proved reserves and related future net cash flows are not precise. The actual quantities of our proved reserves and future net cash flows may prove to be lower than estimated.

Many uncertainties exist in estimating quantities of proved reserves and related future net cash flows. Our estimates are based on various assumptions, which may ultimately prove to be inaccurate.

Generally, lower prices adversely affect the quantity of our reserves as those reserves expected to be produced in later years, which tend to be costlier on a per unit basis, become uneconomic. In addition, a portion of our proved undeveloped reserves may no longer meet the economic producibility criteria under the applicable rules or may be removed due to a lower amount of capital available to develop these projects within the SEC-mandated five-year limit.

In addition, our reserves information represents estimates prepared by internal engineers. Although over 80% of our 2017 proved reserve estimates were audited by our independent petroleum engineers, Ryder Scott Company, L.P., we cannot guarantee that the estimates are accurate. Reserves estimation is a partially subjective process of estimating accumulations of oil and natural gas. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows from those reserves depend upon a number of variables and assumptions, including:

- historical production from the area compared with production from similar areas;
- the quality, quantity and interpretation of available relevant data;
- commodity prices;
- production and operating costs;
- ad valorem, excise and income taxes;
- development costs;
- the effects of government regulations; and
- future workover and asset retirement costs.

Changes in these variables and assumptions could require us to make significant negative reserves revisions, which could affect our liquidity by reducing the borrowing base under our 2014 Revolving Credit Facility. In addition, factors such as the availability of capital, geology, government regulations and permits, the effectiveness of development plans and other factors could affect the source or quantity of future reserves additions.

Risks related to our acquisition and disposition activities could adversely impact our financial condition and results of operations.

Our acquisition activities carry risks that we may: (i) not fully realize anticipated benefits due to less-than-expected reserves or production or changed circumstances; (ii) bear unexpected integration costs or experience other integration difficulties; (iii) experience share price declines based on the market's evaluation of the activity and (iv) assume liabilities that are greater than anticipated. Furthermore, any acquisitions made in foreign countries would expose us to currency, political, marketing, labor and other risks associated with investments in foreign assets.

In connection with our acquisitions, we are often only able to perform limited due diligence. Successful acquisitions of oil and gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing for recovering the reserves, exploration potential, future commodity prices, operating costs and potential environmental, regulatory and other liabilities. Such assessments are inexact and incomplete, and we may be unable to make these assessments with a high degree of accuracy.

Our disposition activities, including JVs, carry risks that we may (i) not be able to realize reasonable prices or rates of return for assets we sell or contribute to JVs; (ii) be required to retain liabilities that are greater than desired or anticipated; (iii) experience increased operating costs and (iv) burden our cash flows and borrowing base if we cannot replace the revenue lost for less than the proceeds from the disposition, or at all.

Our business is highly regulated and government authorities can delay or deny permits and approvals or change legal requirements governing our operations, including hydraulic fracturing and other well stimulation methods, enhanced production techniques and fluid injection or disposal, that could increase costs, restrict operations and delay our implementation of, or cause us to change, our business strategy.

Our operations are subject to complex and stringent federal, state, local and other laws and regulations relating to the exploration and development of our properties, as well as the production, transportation, marketing and sale of our products. Federal, state and local agencies may assert overlapping authority to regulate in these areas. For example, the jurisdiction and enforcement authority of various state agencies have significantly increased with respect to oil and gas activities in recent years, and these agencies have significantly revised their regulations, regulatory interpretations and data collection and plan to issue additional regulations of certain oil and gas activities in 2018. In addition, certain of these federal, state and local laws and regulations may apply retroactively and may impose strict or joint and several liability on us for events or conditions over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

See *Item 1—Business—Regulation of the Oil and Natural Gas Industry* for a description of laws and regulations that affect our business. To operate in compliance with these laws and regulations, we must obtain and maintain permits, approvals and certificates from federal, state and local government authorities for a variety of activities including siting, drilling, completion, stimulation, operation, maintenance, transportation, storage, marketing, site remediation, decommissioning, abandonment, fluid injection and disposal and water recycling and reuse. Failure to comply may result in the assessment of administrative, civil and/or criminal fines and penalties and liability for noncompliance, costs of corrective action, cleanup or restoration, compensation for personal injury, property damage or other losses, and the imposition of injunctive or declaratory relief restricting or prohibiting certain operations. Under certain environmental laws and regulations, we could be subject to strict or joint and several liability for the removal or remediation of contamination, including on properties over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

Our customers, including refineries and utilities, and the businesses that transport our products to customers are also highly regulated. For example, federal and state pipeline safety agencies have adopted or proposed regulations to expand their jurisdiction to include more gas and liquid gathering lines and pipelines and to impose additional mechanical integrity requirements. The state has adopted additional regulations on the storage of natural gas that could affect the demand for or availability of such storage, increase seasonal volatility, or otherwise affect the prices we receive from customers.

Costs of compliance may increase and operational delays or restrictions may occur as existing laws and regulations are revised or reinterpreted, or as new laws and regulations become applicable to our operations, each of which has occurred in the past.

Government authorities and other organizations continue to study health, safety and environmental aspects of oil and gas operations, including those related to air, soil and water quality, ground movement or seismicity and natural resources. Government authorities have also adopted or proposed new or more stringent requirements for permitting, well construction and public disclosure or environmental review of, or restrictions on, oil and gas operations. Such requirements or associated litigation could result in potentially significant added costs to comply, delay or curtail our exploration, development, fluid injection and disposal or production activities, preclude us from drilling, completing or stimulating wells, or otherwise restrict our ability to access and develop mineral rights, any of which could have an adverse effect on our expected production, other operations and financial condition.

For recent examples relating to well stimulation, water management and fluid injection see *Item 1—Business—Regulation of the Oil and Natural Gas Industry*.

Changes in elected officials could result in different approaches to the regulation of the oil and gas industry. In 2018, California will elect a new governor who will take office next year. Representatives in the California legislature will change. We cannot predict the actions the future governor or legislature may take with respect to the regulation of our business, the oil and gas industry or the state's economic fiscal or environmental policies.

Drilling for and producing oil and natural gas carry significant operational and financial risk and uncertainty. We may not drill wells at the times we scheduled, or at all, and wells we do drill may not yield production in economic quantities or generate our expected VCI.

Our decisions to explore, develop, purchase or otherwise exploit prospects or properties depend in part on the evaluation of geophysical, geologic, engineering, production and other technical data and processes. The analysis of these factors is often inconclusive or subject to varying interpretations. Our decisions and ultimate profitability are also affected by commodity prices, the availability of capital, regulatory approvals, available transportation and storage capacity, political resistance and other factors. Our cost of drilling, completing, stimulating, equipping, operating, maintaining and abandoning wells is also often uncertain. As we enter into more JVs, our ability to ramp up and deploy internal capital may be constrained. Our production cost per barrel is higher than that of many of our peers due to the extraction methods we use, the large number of wells we operate and the effects of our PSC contracts. Overruns in budgeted investments are a common risk that can make a particular project uneconomic or less economic than forecast. We bear the risks of equipment failures, accidents, environmental hazards, adverse weather conditions, permitting or construction delays, title disputes, surface access disputes, disappointing drilling results or reservoir performance, including production response to improved recovery or enhanced recovery efforts, and other associated risks. The VCI metric we use to allocate capital is based on estimates of future cash flows and capital investment, and therefore our projects may not generate the expected results.

We have specifically identified locations for drilling over the next several years, which represent a significant part of our long-term growth strategy. Our actual drilling activities may materially differ from those presently identified. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling or development of these projects. We make assumptions about the consistency and accuracy of data when we identify these locations that may prove inaccurate. We cannot guarantee that these exploration drilling locations or any other drilling locations we have identified will ever be drilled or if we will be able to produce crude oil or natural gas from these drilling locations. In addition, some of our leases could expire if we do not establish production in the leased acreage. The combined net acreage covered by leases expiring in the next three years represented approximately 16% of our total net undeveloped acreage at December 31, 2017.

Part of our strategy involves exploratory drilling, including drilling in new or emerging plays. Our drilling results are uncertain, and the value of our undeveloped acreage may decline if drilling is unsuccessful.

The risk profile for our exploration drilling locations is higher than for other locations because we have less geologic and production data and drilling history, in particular those exploration drilling locations in unconventional reservoirs. We may not find commercial amounts of oil or natural gas, in which case the value of our undeveloped acreage may decline and could be impaired. In 2017, we drilled two exploration wells both of which were dry. We may increase the proportion of our drilling in new or emerging plays over time.

One of our important assets is our acreage in the Monterey shale play in the San Joaquin, Los Angeles and Ventura basins. The geology of the Monterey shale is highly complex and not uniform due to localized and varied faulting and changes in structure and rock characteristics. As a result, it differs from other shale plays that can be developed in part on the basis of their uniformity. Instead, individual Monterey shale drilling sites may need to be more fully understood and may require a more precise development approach, which could affect the timing, cost and our ability to develop this asset.

Our commodity-price risk-management activities may prevent us from fully benefiting from price increases and may expose us to other risks.

Our current commodity-price risk-management activities may prevent us from realizing the full benefits of price increases above the levels determined under the derivative instruments we use to manage price risk. In addition, our commodity-price risk-management activities may expose us to the risk of financial loss in certain circumstances, including instances in which the counterparties to our hedging or other price-risk management contracts fail to perform under those arrangements.

Adverse tax law changes may affect our operations.

In California, there have been proposals for new taxes on oil and gas production. Although the proposals have not become law, campaigns by various interest groups could lead to future additional oil and gas severance or other taxes such as extending the state's retail sales tax to many services used in business. In addition to the existing state corporate tax rate of 8.84%, California state lawmakers recently proposed a 10% surcharge on companies with taxable income of over $1 million. The imposition of such taxes could significantly reduce our profit margins and cash flow and could ultimately reduce our capital investments and growth plans.

Our producing properties are located in California, making us vulnerable to risks associated with having operations concentrated in this geographic area.

Our operations are concentrated in California. Because of this geographic concentration, the success and profitability of our operations may be disproportionately exposed to the effect of regional conditions. These include local price fluctuations, changes in state or regional laws and regulations affecting our operations and other regional supply and demand factors, including gathering, pipeline, transportation and storage capacity constraints, limited potential customers, infrastructure capacity and availability of rigs, equipment, oil field services, supplies and labor. The concentration of our operations in California and limited local storage options also increase our exposure to events such as natural disasters, mechanical failures, industrial accidents or labor difficulties. Any one of these events has the potential to cause producing wells to be shut-in, delay operations and growth plans, decrease cash flows, increase operating and capital costs, prevent development of lease inventory before expiration and limit access to markets for our products.

The enactment of derivatives legislation, and the promulgation of regulations pursuant thereto, could have an adverse effect on our ability to use derivative instruments to reduce the effect of risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), enacted in 2010, establishes federal oversight and regulation of the over-the-counter (OTC) derivatives market and entities, like us, that participate in that market. Among other things, the Dodd-Frank Act required the U.S. Commodity Futures Trading Commission to promulgate a range of rules and regulations applicable to OTC derivatives transactions, and these rules may affect both the size of positions that we may enter and the ability or willingness of counterparties to trade opposite us, potentially increasing costs for transactions. Moreover, such changes could materially reduce our hedging opportunities which could adversely affect our revenues and cash flow during periods of low commodity prices.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions or counterparties with other businesses that subject them to regulation in foreign jurisdictions, we may become subject to or otherwise impacted by such regulations. At this time, the impact of such regulations is not clear.

Concerns about climate change and other air quality issues may affect our operations or results.

Concerns about climate change and regulation of GHGs and other air quality issues may materially affect our business in many ways, including increasing the costs to provide our products and services, and reducing demand for, and consumption of, our products and services, and we may be unable to recover or pass through a significant portion of our costs. In addition, legislative and regulatory responses to such issues may increase our operating costs and render certain wells or projects uneconomic, and potentially lower the value of our reserves and other assets. As these requirements become more stringent, we may be unable to implement them in a cost-effective manner. To the extent financial markets view climate change and GHG emissions as a financial risk, this could adversely impact our cost of, and access to, capital. Both the EPA and California have implemented laws, regulations and policies that seek to reduce GHG emissions as discussed in *Item 1—Business—Regulation of the Oil and Natural Gas Industry*. In 2017, we incurred costs of approximately $27 million for mandatory GHG emissions allowances in California, and costs of such allowances per metric ton of GHG emissions are expected to increase in the future as CARB tightens program requirements or as the minimum state auction price of such allowances is increased.

In addition, other current and proposed international agreements and federal and state laws, regulations and policies seek to restrict or reduce the use of petroleum products in transportation fuels, electricity generation and other applications, prohibit future use of certain vehicles and equipment that require petroleum fuels, impose additional taxes and costs on producers and consumers of petroleum products and require or subsidize the use of renewable energy. Various claimants, including certain municipalities, have also filed litigation alleging that energy producers are liable for conditions the claimants attribute to climate change.

Governmental authorities can impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. In addition, California air quality laws and regulations, particularly in southern and central California where most of our operations are located, are in most instances more stringent than analogous federal laws and regulations. For example, the San Joaquin Valley will be required to adopt more rigorous attainment plans under the Clean Air Act to comply with federal ozone and particulate matter standards, and these efforts could affect our activities in the region and our ability to permit new or modified operations.

We may incur substantial losses and be subject to substantial liability claims as a result of catastrophic events. We may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not fully insured against all risks. Our oil and gas exploration and production activities are subject to risks such as fires, explosions, releases, discharges, equipment or information technology failures and industrial accidents. In addition, catastrophic events such as earthquakes, floods, mudslides, wildfires or droughts, cyber or terrorist attacks and other events may cause operations to cease or be curtailed and may adversely affect our business, workforce and the communities in which we operate. We may be unable to obtain, or may elect not to obtain, insurance for certain risks if we believe that the cost of available insurance is excessive relative to the risks presented.

Information technology failures and cyber attacks could affect us significantly.

We rely on electronic systems and networks to communicate, control and manage our operations and prepare our financial management and reporting information. If we record inaccurate data or experience infrastructure outages, our ability to communicate and control and manage our business could be adversely affected. Cyber attacks on businesses have escalated in recent years. If we were to experience an attack and our security measures failed, the potential consequences to our business and the communities in which we operate could be significant.

We are exposed to certain risks related to our separation from Occidental in 2014.

In connection with our separation from Occidental, we entered into contracts that allocate risks and liabilities (including tax liabilities) between Occidental and ourselves. These contracts were not made on an arm’s length basis and include mutual indemnity obligations. Indemnity payments that we may be required to provide Occidental may be significant and could adversely impact our business. Similarly, third parties could also seek to hold us responsible for liabilities that Occidental has agreed to retain and the indemnity from Occidental may not be sufficient or paid timely.

ITEM 1B UNRESOLVED STAFF COMMENTS

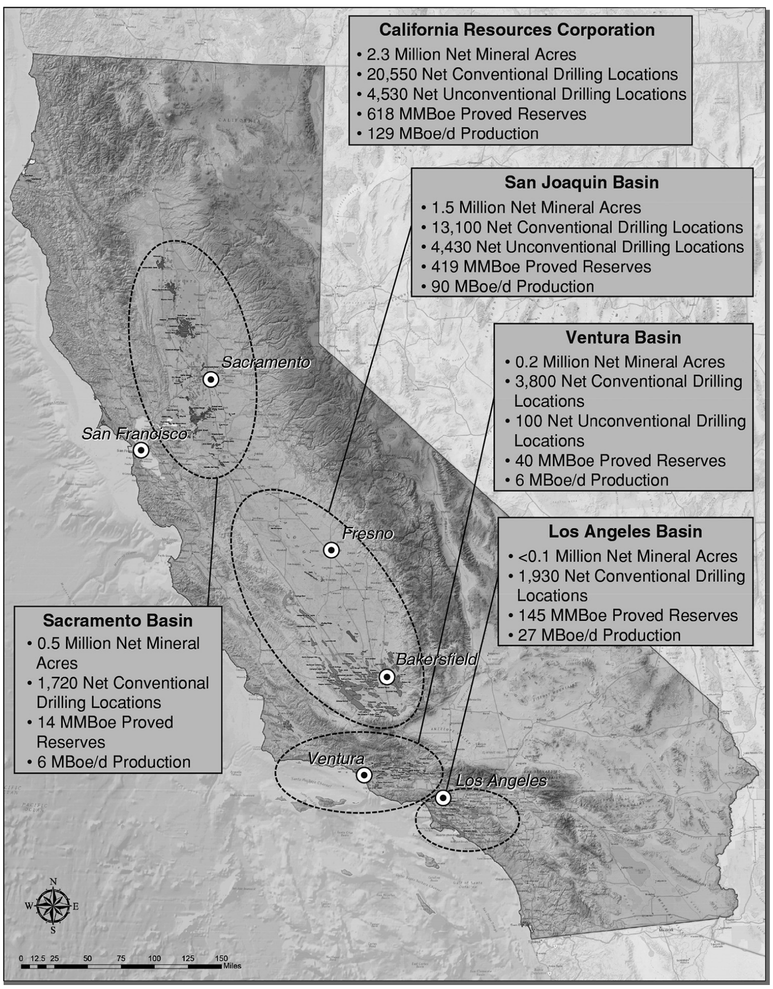
We have no unresolved SEC staff comments at December 31, 2017.

ITEM 2 PROPERTIES

Our Operations

Our Areas of Operation

California is one of the most prolific oil and natural gas producing regions in the world and is currently the fifth largest oil producing state in the nation. According to DOGGR information through 2016, cumulative California production from all four basins in which we operate is 36 billion barrels of oil equivalent (BBoe), including approximately 20 BBoe in the San Joaquin basin, 11 BBoe in the Los Angeles basin, 3 BBoe in the Ventura basin and 2 BBoe in the Sacramento basin. Additionally, Kern County has been one of the top two largest oil producing counties in the lower 48 states for a number of years. Our operations include 135 fields with 8,636 gross producing wells as of December 31, 2017. We believe we are the largest private oil and natural gas mineral acreage holder in California, with interests in approximately 2.3 million net mineral acres. Approximately 60% of our total net mineral interest position is held in fee and 15% is held by production. A majority of our interests are in producing properties located in reservoirs characterized by what we believe to be long-lived production profiles with repeatable development opportunities.



In 2017, we produced 47 million barrels of oil equivalent (MMBoe). We added 56 MMBoe in proved reserves in 2017, comprising 22 MMBoe from positive performance revisions and 34 MMBoe from extensions and discoveries, representing a 119% organic reserves replacement ratio. This was accomplished with a $371 million capital program, of which $362 million was directed to development activities. In addition, positive price-related revisions added another 49 MMBoe of reserves. For further information on our reserves replacement ratio, see *Our Reserves—PV-10, Standardized Measure and Reserves Replacement Ratio* section below.

<u>*San Joaquin Basin*</u>

We actively operate and are developing 46 fields in this inland basin in the southern part of California's central valley. Our assets consist of conventional primary, IOR, EOR and unconventional project types with approximately 1.5 million net mineral acres, approximately 66% of which we hold in fee and another 7% is held by production. Approximately 68% of our estimated proved reserves as of December 31, 2017 were located in, and 70% of our average daily net production for the year ended December 31, 2017 came from, the San Joaquin basin.

According to DOGGR, approximately 75% of California's daily oil production for 2016 was produced in the San Joaquin basin. Commercial petroleum development began in the basin in the 1800s. Rapid discovery of many of the largest oil accumulations followed during the next several decades, including the Elk Hills field. We have been redeveloping this field and building our expertise to use in other fields across the state. According to the U.S. Geological Survey as of 2012, the San Joaquin basin contained three of the 10 largest oil fields in the United States based on cumulative production and proved reserves. We have been successfully developing steamfloods in our Kern Front operations, which are located next to the giant Kern River field, and in the northwest portion of the Lost Hills field. Beginning in the 1980s, reserves additions occurred in the Monterey formation on the west side of the basin and in our new conventional field discoveries. The basin contains multiple stacked formations throughout its areal extent, and we believe that the San Joaquin basin provides an appealing inventory of existing field re-development opportunities, as well as new play discovery and unconventional play potential. The complex stratigraphy and structure in the San Joaquin basin has allowed continuing discoveries of stratigraphic and structural traps. We believe our extensive 3D seismic library, which covers nearly 3,000 square miles in the San Joaquin basin, including 50% of our acreage, will give us a competitive advantage in further exploring this basin.

We have established a large ownership interest in several of the largest existing oil fields in the San Joaquin basin, including Elk Hills, our largest producing field, as well as the Buena Vista and Kettleman North Dome fields.

Elk Hills

Elk Hills is one of the largest fields in the continental United States based on proved reserves and has produced approximately 2.0 BBoe to date. During the year ended December 31, 2017, we produced 48 MBoe/d on average from the Elk Hills properties, or approximately 37% of our total average daily production. Of our total Elk Hills production, 67% is liquids. We also operate efficient natural gas processing facilities, including a state-of-the-art cryogenic gas plant, with a combined gas processing capacity of over 520 MMcf/d. Additionally, one of our subsidiaries generates sufficient electricity to operate the field and sells the excess power to the grid and to utilities. A portion of the excess power is subject to a five-year contract with a local utility, which includes a minimum capacity payment, that provides rates that are better than those that could be received from sales to the grid. Our operations at Elk Hills include a state-of-the-art central control facility and remote automation control on over 95% of our wells in this field.

Los Angeles Basin

We actively operate and are developing 8 fields in this urban, coastal basin which consists of IOR project types, approximately half of which we hold in fee and 52% held by production. Approximately 23% of our estimated proved reserves as of December 31, 2017 were located in, and 20% of our average daily net production for the year ended December 31, 2017 came from, the Los Angeles basin.

The basin is a northwest-trending plain about 50 miles long and 20 miles wide. Most of the significant discoveries in the Los Angeles basin date back to the 1920s. The Los Angeles basin has one of the highest concentrations per acre of crude oil in the world with 68 fields in an area of about 0.3 million acres. The basin contains multiple stacked formations throughout its depths, and we believe that the Los Angeles basin provides a considerable inventory of existing field re-development opportunities as well as new play discovery potential. Large active oil fields include the Wilmington and Huntington Beach fields, where we have significant operations.

Wilmington Field

The Wilmington field located in Long Beach is the fourth largest field in the United States and has produced approximately 3.0 BBoe to date. During the year ended December 31, 2017, we produced approximately 30 MBoe/d gross on average, or 98% of the Wilmington field's daily production from all producers for the year. We operate in this field on behalf of the state of California and the city of Long Beach. Our net production in 2017 of approximately 23 MBoe/d equated to approximately 18% of our total average daily production. Most of our Wilmington production is subject to a set of contracts similar to production-sharing contracts under which we recover the capital and operating costs we incur on behalf of the state and the city of Long Beach and receive our share of profits. We use waterflood recovery methods to develop the field. Our waterflood operations have attractive margins and returns in the current price environment and extend the productive life of our reservoirs beyond the economic life expected for primary development.

Ventura Basin

We actively operate and are developing 28 fields in this central California coastal basin which consists of primary conventional, IOR, EOR and unconventional project types. We currently hold approximately 0.2 million net mineral acres in the Ventura basin, approximately 73% of which we hold in fee and 11% held by production. Approximately 6% of our estimated proved reserves as of December 31, 2017 were located in, and approximately 5% of our average daily net production for the year ended December 31, 2017 came from, the Ventura basin.

The Ventura basin is the onshore part of a structural feature and its offshore extension is the modern Santa Barbara basin. All of the sedimentary section is productive at various locations, and most reservoirs are sandstones with favorable porosity and permeability. The basin contains multiple stacked formations throughout its depths, and we believe that the Ventura basin provides an appealing inventory of existing field re-development opportunities, as well as new exploration potential.

Sacramento Basin

We actively operate and are developing 53 fields in this inland basin in the northern part of California's central valley, primarily consisting of dry gas production. We currently hold approximately 0.5 million net mineral acres in the Sacramento basin, approximately 38% of which we hold in fee and 44% held by production. We believe our significant acreage position in the Sacramento basin gives us the option for future development and rapid production growth in an attractive natural gas price environment. As of December 31, 2017, approximately 2% of our estimated proved reserves were located in the Sacramento basin, which accounted for approximately 5% of our average daily net production for the year.

The Sacramento basin is a deep, thick sequence of sedimentary deposits within an elongated northwest-trending structural feature covering about 7.7 million acres. Exploration and development in the basin began in 1918.

Conventional Reservoir Recovery Methods

We determine which development method to use based on reservoir characteristics, reserves potential and expected returns. We seek to optimize the potential of our conventional assets by progressively using primary recovery methods, which may include some well stimulation techniques, IOR methods like waterflooding and EOR methods such as steamflooding, using both vertical and horizontal drilling. All of these techniques are proven technologies we have used extensively in California.

Primary Recovery

Primary recovery is a reservoir drive mechanism that utilizes the natural energy of the reservoir and is the first technique we use to develop a reservoir. Primary recovery is achieved by drilling and producing wells without supplementing the natural energy of the reservoir. Our successful exploration program continues to provide us with primary recovery opportunities in new reservoirs or through extensions of existing fields. Our conventional development programs create future opportunities to convert these reservoirs to waterfloods or steamfloods after their primary production phase.

Waterfloods

Some of our fields have been partially produced and no longer have sufficient energy to drive oil to our producing wellbores. Waterflooding is a well understood process that has been used in California for over 50 years to re-introduce energy to the reservoir through water injection and to sweep oil to producing wellbores. This process has been known to increase recovery factors from approximately 10% under primary recovery methods to up to approximately 20%. Our waterflood operations have attractive margins and returns in the current price environment. These operations typically have low and predictable production declines and allow us to extend the productive life of a reservoir and significantly increase our incremental recovery after primary recovery. As a result, investments in waterfloods can yield attractive returns even in a low price environment. We use waterfloods extensively in the San Joaquin, Los Angeles and Ventura basins, which has allowed us to reduce production declines or modestly grow our production from mature fields such as Elk Hills and Wilmington.

Steamfloods

Some of our fields contain heavy, thick oil. Steamfloods work by injecting steam into the reservoir to heat the oil, decreasing its viscosity, or thinning the oil, allowing it to flow more easily to the producing wellbores. Steamflooding is a well understood process that has been used in California since the early 1960s. This process has been known to increase recovery factors from approximately 10% under primary recovery methods to up to approximately 75%. Thermal operations are most effective in shallow reservoirs containing heavy, viscous oil. The steamflood process is generally characterized by low capital investment with attractive margins and returns even in a low oil price environment as long as the oil-to-gas price ratio is in excess of five. The economics of steamflooding are largely a function of the ratio between oil and natural gas prices. After drilling, these operations typically ramp up production over one to two years as the steam continues to influence the oil production, and then exhibit a plateau for several months, with a subsequent low, predictable production decline rate of 5 to 10% per year. This gradual decline allows us to extend the productive life of a reservoir and significantly increase our incremental recovery after primary depletion. We use steamfloods extensively in the San Joaquin basin, where they have allowed us to grow our production from mature fields such as Kern Front and Lost Hills, among others.

Unconventional Reservoir

We believe our undeveloped unconventional acreage has the potential to provide significant long-term production growth. In total, we hold mineral interests in approximately 1.3 million net mineral acres with unconventional potential and have identified over 4,930 gross (4,530 net) unconventional drilling locations on this acreage. As a result of our development efforts in previous years, approximately 34% of our 2017 production was from unconventional reservoirs, an increase of approximately 91% since the acquisition of the Elk Hills field properties in 1998. As of December 31, 2017, we had proved reserves of approximately 180 MMBoe associated with our unconventional properties, approximately 26% of which were proved undeveloped reserves.

We hold significant interests in the Monterey formation, which is divided into upper and lower intervals. We have successfully produced from seven discrete stacked pay horizons within the upper Monterey. During the year ended December 31, 2017, we produced approximately 53 MBoe/d on average from upper Monterey. The lower Monterey is recognized as a world-class source rock but has an extremely limited production history compared to the upper Monterey, and therefore very limited knowledge exists regarding its potential. For example, only about 25 wells have tested the lower Monterey to date. However, we believe we will be able to apply knowledge we gain from the upper Monterey to the lower Monterey.

Prior to the severe price declines that began in late 2014, we were focused on higher-value unconventional production from seven discrete stacked pay horizons within the Monterey formation, primarily within the upper Monterey. As commodity prices and project economics improved in 2017, we continued our development activities in the upper Monterey formation and started to appraise and delineate the Kreyenhagen formation within our Kettleman North Dome field. We expect to continue pursuing unconventional opportunities in 2018 and beyond if prices remain at current levels. Over the longer term, as project economics improve, we will seek to duplicate our successful upper Monterey results to develop opportunities in the unconventional reservoirs of the lower Monterey, Kreyenhagen and Moreno formations, which have similar geological attributes.

Exploration Program

We have had a successful exploration program in both conventional and unconventional plays, including during the years prior to Spin-off. Our experienced technical staff, proprietary geological models, leading acreage position and extensive 3D seismic library give us a strong competitive advantage. California is one of the most prolific hydrocarbon producing regions as a result of its world-class source rocks and stacked conventional and unconventional reservoirs. California basins have generated billions of barrels of oil and have established production from over 400 identified reservoir intervals in both structural and stratigraphic trap configurations. Historical industry activity has focused on the primary and secondary development of known hydrocarbon accumulations, many of which were discovered over a century ago. We have significant land positions in under-explored hydrocarbon basins.

We continue to focus on growing our exploration drilling locations and resource identification. We have a ranked near-field portfolio of over 150 exploration prospects across the San Joaquin, Sacramento and Ventura basins. As of December 31, 2017, we had approximately 12,610 gross (5,670 net) exploration drilling locations in conventional reservoirs and approximately 6,400 gross (5,300 net) exploration drilling locations in unconventional reservoirs.

During 2017, we drilled five shallow wells targeting heavy oil accumulations in the San Joaquin basin. All wells encountered hydrocarbons and confirmed potential future development areas. Two of the exploration wells are currently producing, and three of the wells were considered data wells and were plugged and abandoned.

In 2017, we also partnered with third parties in some of our exploration activities, some of which are not included in our consolidated results. These arrangements allow us to defer some of our exploration costs and mitigate technical risks. With a JV partner, we drilled a successful exploration well in a conventional reservoir in the southern San Joaquin basin to a depth of approximately 15,000 feet, which targeted a seismic defined stratigraphic trap in the prolific Stevens Sand reservoir. The initial flow rate of the well was in excess of 300 barrels of oil a day. In connection with this JV, we also acquired 3D seismic data in developed fields that highlighted a number of additional new leads.

At year end, we were in the process of drilling an exploration well in the Sacramento basin. The well encountered multiple stacked gas bearing reservoirs totaling approximately 400 feet in gross thickness. The higher quality reservoirs exhibit porosities ranging from 15% to 20%. An effective well testing program is being planned and will be executed in 2018.

Our Reserves

The information with respect to our estimated reserves presented below has been prepared in accordance with the rules and regulations of the SEC.

Proved oil, NGLs and natural gas reserves were estimated using the unweighted arithmetic average of the first-day-of-the-month price for each month within the year (SEC prices), unless prices were defined by contractual arrangements. Oil, NGLs and natural gas prices used for this purpose were based on spot prices, adjusted for price differentials to account for gravity, quality and transportation costs. For the 2017 reserves estimates, the calculated average Brent oil price was $54.42 per barrel and the average NYMEX gas price was $2.98 per Million British Thermal Units (MMBtu). The average realized prices used for the 2017 disclosures were $51.74 per barrel for oil, $35.05 per barrel for NGLs and $2.59 per Mcf for natural gas.

The following table sets forth our net operating and non-operating interests in quantities of proved developed and undeveloped reserves of oil (including condensate), natural gas liquids (NGLs) and natural gas as of December 31, 2017. Estimated reserves include our economic interests under arrangements similar to production-sharing contracts at our Wilmington field in Long Beach.

	As of December 31, 2017				
	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Proved developed reserves:					
Oil (MMBbl)	176	104	24	—	304
NGLs (MMBbl)	43	—	2	—	45
Natural Gas (Bcf)	447	6	20	70	543
Total (MMBoe)[(a)(b)]	294	105	29	12	440
Proved undeveloped reserves:					
Oil (MMBbl)	89	39	10	—	138
NGLs (MMBbl)	13	—	—	—	13
Natural Gas (Bcf)	138	4	6	15	163
Total (MMBoe)[(b)]	125	40	11	2	178
Total proved reserves:					
Oil (MMBbl)	265	143	34	—	442
NGLs (MMBbl)	56	—	2	—	58
Natural Gas (Bcf)	585	10	26	85	706
Total (MMBoe)[(b)]	419	145	40	14	618

(a) As of December 31, 2017, approximately 21% of proved developed oil reserves, 9% of proved developed NGLs reserves, 15% of proved developed natural gas reserves and, overall, 19% of total proved developed reserves are non-producing. A majority of our non-producing reserves relate to steamfloods and waterfloods where full peak production response has not yet occurred due to the nature of such projects.

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

__Proved Reserves Additions__

The components of the changes to our proved reserves (in MMBoe) during the years ended December 31, 2017, 2016 and 2015 were as follows:

	San Joaquin Basin	Los Angeles Basin[(a)]	Ventura Basin	Sacramento Basin	Total
Balance at December 31, 2014	525	166	58	19	768
Revisions related to price	(50)	(85)	(12)	(6)	(153)
Revisions related to performance	(8)	51	(1)	3	45
Improved recovery	3	—	—	—	3
Extensions and discoveries	15	12	5	1	33
Purchases	6	—	—	—	6
Sales	—	—	—	—	—
Production	(40)	(12)	(3)	(3)	(58)
Balance at December 31, 2015	451	132	47	14	644
Revisions related to price	(17)	(23)	(20)	—	(60)
Revisions related to performance	12	—	2	(1)	13
Improved recovery	3	—	—	—	3
Extensions and discoveries	16	1	3	—	20
Purchases	—	—	—	—	—
Sales	—	(1)	—	—	(1)
Production	(36)	(10)	(3)	(2)	(51)
Balance at December 31, 2016	429	99	29	11	568
Revisions related to price	16	23	9	1	49
Revisions related to performance	(6)	24	2	2	22
Improved recovery	—	—	—	—	—
Extensions and discoveries	19	9	4	2	34
Purchases	—	—	—	—	—
Sales	(6)	—	(2)	—	(8)
Production	(33)	(10)	(2)	(2)	(47)
Balance at December 31, 2017	419	145	40	14	618

Note: 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.

(a) Includes proved reserves related to economic arrangements similar to PSCs of 108 MMBbl, 85 MMBbl, 103 MMBbl and 116 MMBbl at December 31, 2017, 2016, 2015 and 2014, respectively.

Our ability to add reserves, other than through purchases, depends on the success of improved recovery, extension and discovery projects, each of which depends on reservoir characteristics, technology improvements and oil and natural gas prices, as well as capital and operating costs. Many of these factors are outside management's control, and will affect whether the historical sources of proved reserves additions continue to provide reserves at similar levels.

Revisions of Previous Estimates

Revisions related to price—Product price changes affect the proved reserves we record. For example, higher prices generally increase the economically recoverable reserves in all of our operations, because the extra margin extends their expected lives and renders more projects economic. Partially offsetting this effect, higher prices decrease our share of proved cost recovery reserves under arrangements similar to production-sharing contracts at our Wilmington field in Long Beach because fewer reserves are required to recover costs. Conversely, when prices drop, we experience the opposite effects. In 2017, our total net positive price revision was 49 MMBoe, which was primarily the result of higher prices net of modestly higher operating costs due to the current commodity price environment, partially reinstating reserves that were removed in prior years due to lower prices. In 2016 and 2015, total net negative price revisions were 60 MMBoe and 153 MMBoe, respectively. The 2016 and 2015 price revisions incorporated the negative effect of lower prices, partially offset by the positive effect of lower operating costs also caused by the lower commodity price environment.

Revisions related to performance—Performance-related revisions can include upward or downward changes to previous proved reserves estimates due to the evaluation or interpretation of recent geologic, production decline or operating performance data. In 2017, our net positive performance-related revision of 22 MMBoe resulted primarily from the successful renegotiation of our Huntington Beach royalty agreement and improved performance in the San Joaquin basin, partially offset by negative revisions to remove proved undeveloped reserves due to a downward adjustment of our committed capital in a project area and technical revisions due to updated testing results in one of our project areas. In 2016, our positive performance related revisions of 13 MMBoe resulted primarily from better-than-expected reservoir performance and comprehensive field development planning. These positive revisions primarily came from the San Joaquin and Ventura basins. In 2015, our positive performance related revisions of 45 MMBoe resulted primarily from better-than-expected reservoir performance in our San Joaquin and Los Angeles basins, combined with lower development capital than previously estimated.

Improved Recovery

In 2017, there were no material reserves added from improved recovery. We added proved reserves of 3 MMBoe from improved recovery through proven IOR and EOR methods in 2016 and in 2015. The improved recovery additions in both of those years were associated with the continued development of steamflood and waterflood properties in the San Joaquin basin.

Extensions and Discoveries

In 2017, we added 34 MMBoe of proved reserves primarily from extensions, which were associated with the continued successful drilling program mostly in the San Joaquin and Los Angeles basins. Our drilling program in the San Joaquin basin benefited from the deployment of JV capital at Elk Hills and at waterflood projects in Buena Vista. Our drilling program in the Los Angeles basin resulted in expanded economic inventory due to improvements in performance compared to 2016. We also added new projects in the Sacramento basin as a result of analyzing new data from capital workover projects. In 2016 and 2015, we added 20 MMBoe and 33 MMBoe, respectively, of proved reserves from extensions and discoveries, which generally resulted from exploration and development programs primarily in the San Joaquin, Los Angeles and Ventura basins.

Sales

In 2017, we sold 8 MMBoe of proved reserves based on beginning-of-year reserves balances. Included in this amount was 7 MMBoe of proved undeveloped reserves in the San Joaquin basin conveyed to MIRA as part of our JV with MIRA.

Proved Undeveloped Reserves

The total changes to our proved undeveloped reserves during the year ended December 31, 2017 were as follows (in MMBoe):

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Balance at December 31, 2016	142	16	4	—	162
Revisions of previous estimates					
Revisions related to performance	(21)	9	(2)	—	(14)
Revisions related to price changes	5	9	5	—	19
Total revisions of previous estimates	(16)	18	3	—	5
Extensions and discoveries	15	7	4	2	28
Sales	(7)	—	—	—	(7)
Transfers to proved developed reserves	(9)	(1)	—	—	(10)
Balance at December 31, 2017	125	40	11	2	178

In 2017, we had 19 MMBoe of positive price-related revisions, partially offset by 14 MMBoe negative performance-related revisions. Our positive price revisions were primarily the result of the higher commodity price environment, partially offset by the effect of modestly higher operating costs. We had negative performance-related revisions primarily resulting from a downward adjustment of our committed capital in a project area and technical revisions due to updated testing results in one of our project areas. These negative performance-related revisions were partially offset by positive revisions related to the successful renegotiation of our Huntington Beach royalty agreement in the Los Angeles basin.

We had proved undeveloped reserves additions of 28 MMBoe primarily from extensions, which were associated with the continued successful drilling program primarily in the San Joaquin and Los Angeles basins. See more discussion of proved reserves additions from the extensions section above.

We transferred 10 MMBoe of proved undeveloped reserves to the proved developed category as a result of the 2017 development program, all of which was in the San Joaquin and Los Angeles basins. As a result, we converted approximately 6% of our beginning-of-year proved undeveloped reserves to proved developed reserves during the year, investing approximately $98 million of capital. The conversion rate reflected the lack of capital in 2016 and only a gradual ramp up of capital during 2017. In addition, 7 MMBoe of our proved undeveloped reserves in the San Joaquin basin were conveyed to the MIRA JV. We expect that, at about $65 to $75 average Brent prices, we will continue to grow our program and have sufficient future capital to develop our proved undeveloped reserves existing at December 31, 2017.

Our year-end development plans and associated proved undeveloped reserves are consistent with SEC guidelines for development within five years. We believe we will have sufficient capital to develop all proved undeveloped reserves within five years of their original booking date and management commitment to do so. Our conclusion is based on $65 average Brent price for 2018, $70 average Brent price for 2019, and $75 thereafter. Prices that are significantly below these levels for a prolonged period could require us to reduce expected capital investment over the next five years, potentially impacting either the quantity or the development timing of proved undeveloped reserves. For example, if the five-year average price remained at $65 Brent, we would need to remove approximately 8% from our proved undeveloped reserves.

PV-10, Standardized Measure and Reserves Replacement Ratio

As of December 31, 2017, our standardized measure of discounted future net cash flows (Standardized Measure) was $3.8 billion and PV-10 was over $4.5 billion. In addition, we organically replaced 119% of our proved reserves in 2017.

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. Standardized 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.

	As of December 31, 2017
	($ in millions)
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	$ 4,545
Organic reserves replacement ratio[(a)]	119%

(a) 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 revisions, divided by oil-equivalent production. There is no guarantee that historical sources of reserves additions will continue as many factors are fully or partially outside management's control, including commodity prices, availability of capital and the underlying geology, all of which 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.

Reserves Evaluation and Review Process

Our estimates of proved reserves and associated discounted future net cash flows as of December 31, 2017 were made by our technical personnel, such as reservoir engineers and geoscientists, with the assistance of operational and financial personnel and are the responsibility of management. The estimation of proved reserves is based on the requirement of reasonable certainty of economic producibility and management's funding commitments to develop the reserves. Reserves volumes are estimated by forecasts of production rates, operating costs and capital investments. Price differentials between specified benchmark prices and realized prices and specifics of each operating agreement are then applied against the SEC Price to estimate the net reserves. Production rate forecasts are derived using a number of methods, including estimates from decline-curve analysis, type-curve analysis, material balance calculations, which take into account the volumes of substances replacing the volumes produced and associated reservoir pressure changes, seismic analysis and computer simulations of reservoir performance. These field-tested technologies have demonstrated reasonably certain results with consistency and repeatability in the formations being evaluated or in analogous formations. Operating and capital costs are forecast using the current cost environment (without accounting for possible cost changes) applied to expectations of future operating and development activities related to the proved reserves.

Net proved developed reserves are those volumes that are expected to be recovered through existing wells with existing equipment and operating methods, for which the incremental cost of any additional required investment is relatively minor. Net proved undeveloped reserves are those volumes that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required.

Our Vice President, Reserves and Corporate Development has primary responsibility for overseeing the preparation of our reserves estimates. She has over 14 years of experience as an energy sector engineer including as a Senior Reservoir Engineer with Ryder Scott Company, L.P. (Ryder Scott). She is a member of the Society of Petroleum Engineers (SPE) for which she served as past chair of the U.S. Registration Committee. She holds a Master of Business Administration from the Massachusetts Institute of Technology, a Master of Engineering in Petroleum Engineering from the University of Houston and a Bachelor of Science from the University of Florida. She is also a registered Professional Engineer in the state of Texas.

We have an Oil and Gas Reserves Review Committee (Reserves Committee), consisting of senior corporate officers, which reviewed and approved our oil and natural gas reserves for 2017. The Reserves Committee reports to the Audit Committee during the year.

Audits of Reserves Estimates

Ryder Scott was engaged to provide an independent audit of our 2017 and 2016 reserves estimates for fields that in each year comprised at least 80% of our total proved reserves. The primary technical engineer responsible for our audit has 38 years of petroleum engineering experience, the majority of which has been in the estimation and evaluation of reserves. He serves on the Ryder Scott Board of Directors and is a registered Professional Engineer in the state of Texas.

The 2017 reserves audit included a detailed review of 82% of our total proved reserves. For 2017, 2016 and 2015 combined, Ryder Scott audited more than 95% of our total proved reserves. Ryder Scott examined the assumptions underlying our reserves estimates, adequacy and quality of our work product, and estimates of future production rates, net revenues, and the present value of such net revenues. Ryder Scott also examined the appropriateness of the methodologies employed to estimate our reserves as well as their categorization, using the definitions set forth by the SEC, and found them to be appropriate. As part of their process, Ryder Scott developed their own independent estimates of reserves for those fields that they audited. When compared on a field-by-field basis, some of our estimates were greater and some were less than the estimates of Ryder Scott. Given the inherent uncertainties and judgments in estimating proved reserves, differences between our and Ryder Scott's estimates are to be expected. The aggregate difference between our estimates and Ryder Scott's was less than 10%, which was within SPE's acceptable tolerance.

In the conduct of the reserves audit, Ryder Scott did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, crude oil and natural gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the fields and sales of production. However, if anything came to Ryder Scott's attention which brought into question the validity or sufficiency of any such information or data, Ryder Scott would not rely on such information or data until it had resolved its questions relating thereto or had independently verified such information or data.

Ryder Scott determined that our estimates of reserves have been prepared in accordance with the definitions and regulations of the SEC as well as the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions. Ryder Scott issued an unqualified audit opinion on our proved reserves at December 31, 2017. Ryder Scott's report is attached as an exhibit to this Form 10-K.

Drilling Locations

Proven Drilling Locations

Based on our reserves report as of December 31, 2017, we have approximately 2,090 gross (1,870 net) drilling locations attributable to our proved undeveloped reserves. We use production data and experience gained from our development programs to identify and prioritize this proven drilling inventory. These drilling locations are included in our inventory only after we have adopted a development plan to drill them within a five-year time frame. As a result of rigorous technical evaluation of geologic and engineering data, we can estimate with reasonable certainty that reserves from these locations will be commercially recoverable in accordance with SEC guidelines. Management considers the availability of local infrastructure, drilling support assets, state and local regulations and other factors it deems relevant in determining such locations.

Unproven Drilling Locations

We have also identified a multi-year inventory of 19,170 gross (17,540 net) drilling locations that are not associated with proved undeveloped reserves but are specifically identified on a field-by-field basis considering the applicable geologic, engineering and production data. We analyze past field development practices and identify analogous drilling opportunities taking into consideration historical production performance, estimated drilling and completion costs, spacing and other performance factors. These drilling locations primarily include (i) infill drilling locations, (ii) additional locations due to field extensions or (iii) potential IOR and EOR project expansions, some of which are currently in the pilot phase across our properties, but have yet to be moved to the proven category. We believe the assumptions and data used to estimate these drilling locations are consistent with established industry practices with well spacing selected based on the type of recovery process we are using.

Exploration Drilling Locations

Conventional – Our exploration portfolio contains approximately 12,610 gross (5,670 net) unrisked prospective drilling locations in conventional reservoirs, the majority of which are located near existing producing fields. We use internally generated information and proprietary geologic models consisting of data from analog plays, 3D seismic data, open hole and mud log data, cores and reservoir engineering data to help define the extent of the targeted intervals and the potential ability of such intervals to produce commercial quantities of hydrocarbons. Information used to identify exploration locations includes both our own proprietary data, as well as industry data available in the public domain. After defining the potential areal extent of an exploration prospect, we identify our exploration drilling locations within the prospect by applying the well spacing historically utilized for the applicable type of recovery process used in analogous fields.

Unconventional – We have approximately 6,400 gross (5,300 net) unrisked prospective resource drilling locations identified in the lower Monterey, Kreyenhagen and Moreno unconventional reservoirs based on screening criteria that include geologic and economic considerations and limited production information. Prospective play areas are defined by geologic data consisting of well cuttings, hydrocarbon shows, open-hole well logs, geochemical data, available 3D or 2D seismic data and formation pressure data, where available. Information used to identify our prospective locations includes both our own proprietary data, as well as industry data available in the public domain. We identify our prospective resource drilling locations based on an assumption of 80-acre spacing per well throughout the prospective area for each resource play.

Well Spacing Determination

Our well spacing determinations in the above categories of identified well locations are based on actual operational spacing within our existing producing fields, which we believe are reasonable for the particular recovery process employed (e.g., primary, waterflood or EOR). Due to the significant vertical thickness and multiple stacked reservoirs usually encountered by our drilling wells, typical well spacing is generally less than 20 acres and often 10 acres or less in the majority of our fields unless specified differently above. These parameters also meet the general well spacing restrictions imposed on certain oil and gas fields in California.

Drilling Schedule

Our identified drilling locations have been scheduled as part of our current multi-year drilling schedule or are expected to be scheduled in the future. However, we may not drill our identified sites at the times scheduled or at all. We view the risk profile for our exploration drilling locations as being higher than for our other drilling locations due to relatively less available geologic and production data and drilling history, in particular with respect to our prospective resource locations in unconventional reservoirs, which are in unproven geologic plays. We make assumptions about the consistency and accuracy of data when we identify these locations that may prove inaccurate.

Our ability to profitably drill and develop our identified drilling locations depends on a number of variables, including crude oil and natural gas prices, capital availability, costs, drilling results, regulatory approvals, available transportation capacity and other factors. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling or development of these projects. For a discussion of the risks associated with our drilling program, see *Item 1A—Risk Factors—Risks Related to Our Business and Industry*.

The table below sets forth our total gross identified drilling locations as of December 31, 2017, excluding our exploration drilling locations related to unconventional reservoirs.

	Proven Drilling Locations		Total Identified Drilling Locations	
	Oil and Natural Gas Wells	Injection Wells	Oil and Natural Gas Wells	Injection Wells
San Joaquin Basin				
Primary Conventional	120	—	8,490	—
Steamflood	660	160	8,420	460
Waterflood	140	60	2,000	990
Unconventional	270	—	4,830	—
San Joaquin Basin subtotal	1,190	220	23,740	1,450
Los Angeles Basin				
Primary Conventional	—	—	—	—
Steamflood	—	—	—	—
Waterflood	410	140	1,460	490
Unconventional	—	—	—	—
Los Angeles Basin subtotal	410	140	1,460	490
Ventura Basin				
Primary Conventional	30	—	1,850	—
Steamflood	—	—	120	—
Waterflood	40	40	1,660	580
Unconventional	—	—	100	—
Ventura Basin subtotal	70	40	3,730	580
Sacramento Basin				
Primary Conventional	20	—	2,420	—
Sacramento Basin subtotal	20	—	2,420	—
Total Identified Drilling Locations	1,690	400	31,350	2,520

Production, Price and Cost History

Oil, NGLs and natural gas are commodities, and the price that we receive for our production is largely a function of market supply and demand. Product prices are affected by a variety of factors, including changes in consumption patterns; inventory levels; global and local economic conditions; the actions of OPEC and other significant producers and governments; actual or threatened production; refining and processing disruptions; currency exchange rates; worldwide drilling and exploration activities; the effects of conservation, weather, geophysical and technical limitations; technological advances; transportation and storage capacity, bottlenecks and costs in producing areas; alternative energy sources; regional market conditions; other matters affecting the supply and demand dynamics for our products; and the effect of changes in these variables on market perceptions. Given the volatile oil price environment, as well as our leverage, we have a hedging program to help protect our cash flow and capital investment program.

Fixed and Variable Costs

Our total production costs consist of variable costs that tend to vary depending on production levels, and fixed costs that typically do not vary with changes in production levels or well counts, especially in the short term. The substantial majority of our near-term fixed costs become variable over the longer term because we manage them based on the field’s stage of life and operating characteristics. For example, portions of labor and material costs, energy, workovers and maintenance expenditures correlate to well count, production and activity levels. Portions of these same costs can be relatively fixed over the near term; however, they are managed down as fields mature in a manner that correlates to production and commodity price levels. While a certain amount of costs for facilities, surface support, surveillance and related maintenance can be regarded as fixed in the early phases of a program, as the production from a certain area matures, well count increases and daily per well production drops, such support costs can be reduced and consolidated over a larger number of wells, reducing costs per operating well. Further, many of our other costs, such as property taxes and oilfield services, are variable and will respond to activity levels and tend to correlate with commodity prices. Overall, we believe approximately one-third of our operating costs are fixed over the life cycle of our fields. We actively manage our fields to optimize production and costs. When we see growth in a field we increase capacities, and similarly when a field nears the end of its economic life we manage the costs while it remains economically viable to produce.

The following table sets forth information regarding our production, average realized and benchmark prices, and costs for oil and gas producing activities for the years ended December 31, 2017, 2016 and 2015. For additional information on price calculations, see information set forth in *Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Production and Prices*.

	Year Ended December 31,		
	2017	**2016**	**2015**
Production Data:			
Oil (MBbl/d)	83	91	104
NGLs (MBbl/d)	16	16	18
Natural gas (MMcf/d)	182	197	229
Average daily combined production (MBoe/d)(a)	129	140	160
Total combined production (MMBoe)(a)	47	51	58
Average realized prices:			
Oil prices with hedge ($/Bbl)	$ 51.24	$ 42.01	$ 49.19
Oil prices without hedge ($/Bbl)	$ 51.47	$ 39.72	$ 47.15
NGLs prices ($/Bbl)	$ 35.76	$ 22.39	$ 19.62
Natural gas prices ($/Mcf)(b)	$ 2.67	$ 2.28	$ 2.66
Average benchmark prices:			
Brent oil ($/Bbl)	$ 54.82	$ 45.04	$ 53.64
WTI oil ($/Bbl)	$ 50.95	$ 43.32	$ 48.80
NYMEX gas ($/MMBtu)	$ 3.09	$ 2.42	$ 2.75
Average costs per Boe:			
Production costs	$ 18.64	$ 15.61	$ 16.30
Production costs, excluding effects of PSC contracts(c)	$ 17.48	$ 14.69	$ 15.58
Field general and administrative expenses(d)	$ 0.82	$ 0.84	$ 1.31
Field general and administrative expenses, adjusted(e)	$ 0.72	$ 0.72	$ 1.00
Field other operating expenses(d)	$ 0.66	$ 1.02	$ 1.78
Field other operating expenses, adjusted(f)	$ 0.56	$ 0.67	$ 0.36
Field depreciation, depletion and amortization(d)	$ 10.85	$ 10.28	$ 16.72
Field taxes other than on income(d)	$ 2.34	$ 2.36	$ 2.67

(a) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas to one Bbl of oil.

(b) For 2015, the average realized price of gas includes the effect of hedges.

(c) The reporting of our PSC-like contracts creates a difference between reported production costs, which are for the full field, and reported volumes, which are only our net share, inflating the per barrel production costs. The amounts represent the production costs for the company after adjusting for this difference.

(d) Amounts exclude corporate charges.

(e) Amounts exclude corporate charges. Amounts also exclude unusual and infrequent charges related to severance and early retirement costs associated with field personnel totaling $0.10 per Boe, $0.12 per Boe and $0.31 per Boe for 2017, 2016 and 2015, respectively.

(f) Amounts exclude corporate charges. For 2017, the amounts also exclude net unusual and infrequent charges of $0.10 primarily related to rig termination expenses partially offset by property tax refunds, recovery of amounts due from joint interest partners and other items. For 2016, the amount also excludes net unusual and infrequent gains of $0.35 that include refunds partially offset by plant turnaround charges and other items. For 2015, the amount also excludes charges related to the write-down of certain assets and rig termination charges of $1.42 per Boe.

The following table sets forth information regarding production, realized prices and production costs for our largest two fields, Elk Hills and Wilmington, for the years ended December 31, 2017, 2016 and 2015:

	Elk Hills			Wilmington		
	2017	**2016**	**2015**	**2017**	**2016**	**2015**
Production data:						
Oil (MBbl/d)	19	21	24	23	25	28
NGLs (MBbl/d)	13	13	15	—	—	—
Natural gas (MMcf/d)	95	106	123	1	—	1
Average realized prices:[(a)]						
Oil (MBbl/d)	$ 55.58	$ 44.50	$ 52.78	$ 49.87	$ 37.98	$ 45.50
NGLs (MBbl/d)	$ 36.26	$ 23.03	$ 20.12	$ —	$ —	$ —
Natural gas (MMcf/d)	$ 2.52	$ 2.27	$ 2.67	$ 2.12	$ 1.83	$ 2.05
Production costs per Boe[(b)]	$ 11.76	$ 10.48	$ 11.11	$ 27.91	$ 22.27	$ 21.87
Production costs, excluding effects of PSC contracts[(c)]	N/A	N/A	N/A	$ 21.59	$ 17.21	$ 17.74

(a) Excludes the effect of hedges.

(b) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas to one Bbl of oil.

(c) The reporting of our PSC-like contracts creates a difference between reported production costs, which are for the full field, and reported volumes, which are only our net share, inflating the per barrel production costs. The amounts represent the production costs for the Company after adjusting for this difference.

The following table sets forth our reserves and production by basin and recovery mechanism:

	Total Proved Reserves		Average Net Daily Production(MBoe/d)
	% of Total Basin	Oil (%)	Year ended December 31, 2017
San Joaquin Basin			
Primary Conventional	13%	64%	13
Waterfloods	14%	76%	8
Steamfloods[(a)]	30%	100%	25
Unconventional	43%	33%	44
San Joaquin Basin subtotal[(b)]	419	63%	90
Los Angeles Basin			
Primary Conventional	—	—%	—
Waterfloods	100%	99%	27
Steamfloods	—	—	—
Unconventional	—	—	—
Los Angeles Basin subtotal[(b)]	145	99%	27
Ventura Basin			
Primary Conventional	35%	80%	3
Waterfloods	65%	86%	3
Steamfloods	—	—	—
Unconventional	—	—	—
Ventura Basin subtotal[(b)]	40	85%	6
Sacramento Basin			
Primary Conventional	100%	—	6
Sacramento Basin subtotal[(b)]	14	—	6
Total	618	72%	129

(a) Includes reserves and production from gas injection of 12% and 10%, respectively.
(b) Subtotal basin reserves in MMBoe.

Productive Wells

Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Net wells represent the sum of fractional interests in wells in which we own an interest. Our average working interest in our producing wells is approximately 87%. Wells are categorized based on the primary product they produce.

The following table sets forth our productive oil and natural gas wells (both producing and capable of production) as of December 31, 2017, excluding wells that have been idle for more than five years:

	As of December 31, 2017			
	Productive Oil Wells		Productive Gas Wells	
	Gross(a)	Net(b)	Gross(a)	Net(b)
San Joaquin Basin	8,058	6,826	162	135
Los Angeles Basin	1,629	1,579	1	1
Ventura Basin	819	812	—	—
Sacramento Basin	—	—	965	886
Total(c)	10,506	9,217	1,128	1,022
Multiple completion wells included above	57	54	48	44

(a) The total number of wells in which interests are owned.
(b) Sum of our fractional interests.
(c) This total represents both producing and capable of producing wells. As of December 31, 2017, we had 2,690 gross (2,455 net) oil wells and 308 gross (283 net) gas wells that are capable of production but currently not producing, and a total of 8,636 gross (7,501 net) producing wells, approximately 91% of which were oil wells.

Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we owned an interest as of December 31, 2017, of which approximately 60% is held in fee, 15% is held by production and 25% are term leases.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
	(in thousands)				
Developed(a)					
Gross(b)	417	21	63	267	768
Net(c)	379	16	61	247	703
Undeveloped(d)					
Gross(b)	1,317	17	224	341	1,899
Net(c)	1,087	14	187	261	1,549

(a) Acres spaced or assigned to productive wells.
(b) Total number of acres in which interests are owned.
(c) Sum of our fractional interests based on working interests or interests under arrangements similar to production-sharing contracts.
(d) Acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether the acreage contains proved reserves.

Work programs are designed to ensure that the exploration potential of any leased property is fully evaluated before expiration. In some instances, we may relinquish leased acreage in advance of the contractual expiration date if the evaluation process is complete and there is no longer a commercial reason for leasing that acreage. In cases where we determine we want to take the additional time required to fully evaluate acreage, we have generally been successful in obtaining extensions. The combined net acreage covered by leases expiring in the next three years represents approximately 16% of our total net undeveloped acreage at December 31, 2017 and these expirations would not have a material adverse impact on us. Historically, we have not dedicated any significant portion of our capital program to prevent lease expirations and do not expect we will need to do so in the future.

Drilling Activities

The following table sets forth information with respect to our net exploration and development wells completed during the periods indicated. Net wells represent the sum of fractional interests in wells in which we own an interest. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
2017					
Oil					
Exploratory	2	—	—	—	2
Development	92	15	2	—	109
Dry					
Exploratory	3	—	—	—	3
Development	—	—	—	—	—
2016					
Oil					
Exploratory	—	—	—	—	—
Development	37	5	—	—	42
2015					
Oil					
Exploratory	3	—	—	—	3
Development	254	29	—	—	283

The following table sets forth information with respect to our exploration and development wells for which drilling was in progress or pending completion as of December 31, 2017, which are not included in the above table.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Exploratory and development wells					
Gross[(a)]	13	—	1	1	15
Net[(b)]	12	—	1	—	13

(a) The total number of wells in which interests are owned.
(b) Sum of our fractional interests.

On a gross basis, these projects included four primary, six steamfloods, one waterflood and two unconventional wells in the San Joaquin basin, as well as one primary project in each of the Ventura and Sacramento basins.

Delivery Commitments

We have made short-term commitments to certain refineries and other buyers to deliver oil, natural gas and NGLs. As of December 31, 2017, we had oil, natural gas and NGL delivery commitments of 47 MBbl/d, 56 MMcf/d and 18 MBbl/d, respectively, through May 2018. These are index-based contracts with prices set at the time of delivery. We have significantly more production capacity than the amounts committed for oil and natural gas. We have agreements to purchase third-party NGLs for any shortfall between the committed quantities and our production. Further, we have the ability to secure additional volumes for all products if necessary. None of the commitments are expected to have a material impact on our financial statements.

Our Infrastructure

We own a network of infrastructure that is integral to and significantly complements our operations. Our significant footprint in California and wide network of infrastructure helps us connect to third-party transportation pipelines, providing us with a competitive advantage by reducing our operating costs. In February 2018, we entered into a midstream JV in which the Ares JV holds the Elk Hills natural gas processing plant and power plant described below. For further information regarding the Ares JV, see *Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Joint Ventures*.

Our infrastructure includes the following:

Description	Quantity	Unit[(a)]	Capacity		
			San Joaquin Basin	Other Basins	Total
Gas Plants	9	MMcf/d	610	50	660
Power Plants/Co-generation	3	MW	600	50	650
Steam Generators/Plants	>50	MBbl/d	220	—	220
Compressors	400	MHp	300	20	320
Water Management Systems	22	MBw/d	2,400	2,100	4,500
Water Softeners	30	MBw/d	265	—	265
Oil and NGL Storage		MBbls	580	660	1,240
Gathering Systems		Miles			>20,000

(a) MW refers to megawatts of power; MHp refers to thousand horsepower; MBw/d refers to thousand barrels of water per day; MBbls refers to thousands of barrels.

Gas Processing

We believe we own the largest gas processing system in California. In the San Joaquin basin, the Elk Hills cryogenic gas plant has a capacity of 200 MMcf/d of inlet gas, bringing our total processing capacity in the basin to over 610 MMcf/d. We also own and operate a system of natural gas processing facilities in the Ventura basin that are capable of processing equity wellhead gas from the surrounding areas. Our natural gas processing facilities are interconnected via pipelines to nearby third-party rail and trucking facilities, with access to various North American NGL markets. In addition, we have truck rack facilities coupled with a battery of pressurized storage tanks at the Elk Hills natural gas processing facility for NGL sales to third parties.

Electricity

The 550 megawatt combined-cycle Elk Hills power plant, owned by one of our subsidiaries and located adjacent to the Elk Hills gas processing facility, generates all the electricity needs for our Elk Hills and contiguous operations in the San Joaquin basin. We utilize approximately a third of its capacity for our operations and our subsidiary sells the excess to utilities. The Elk Hills power plant also provides primary steam supply to our cryogenic gas plant. We also operate, as needed, a 45 megawatt cogeneration facility at Elk Hills that provides additional flexibility and reliability to support field operations. Within our Long Beach operations in the Los Angeles basin, we operate a 48 megawatt power generating facility that provides over 40% of our Long Beach operation's electricity requirements. All of these facilities are integrated with our operations to improve their reliability and performance while reducing operating costs.

Steam Infrastructure

We own, control and operate all of our steam generation infrastructure in the San Joaquin basin, including steam generators, steam plants, steam distribution systems, steam injection lines and headers, water softeners and water disposal systems. We soften and self-supply water to generate steam, reducing our operating costs. This infrastructure is integral to our operations in San Joaquin basin and supports our high margin and shallow- to medium-depth oil fields such as Kern Front and Lost Hills.

Gathering Systems

We own an extensive network of over 20,000 miles of oil and gas gathering lines. These gathering lines are dedicated almost entirely to collecting our oil and gas production and are in close proximity to field specific facilities such as tank settings or central processing sites. These lines connect our producing wells and facilities to gathering networks, natural gas collection and compression systems, and water and steam processing, injection and distribution systems. Our oil gathering systems connect to multiple third-party transportation pipelines, which increases our flexibility to ship to various parties. In addition, virtually all of our natural gas facilities connect with major third-party natural gas pipeline systems. As a result of these connections, we typically have the ability to access multiple delivery points to improve the prices we obtain for our oil and natural gas production.

Oil and NGL Storage

Our tank storage capacity throughout California gives us flexibility for a period of time to store crude oil and NGLs, allowing us to continue production and avoid or delay any field shutdowns in the event of temporary power, pipeline or other shutdowns.

ITEM 3 LEGAL PROCEEDINGS

In the fourth quarter of 2017, one of our subsidiaries settled previously disclosed notices of violation issued by the South Coast Air Quality Management District to our subsidiary and its predecessor alleging that emissions at a facility in Huntington Beach, California exceeded permit conditions over certain periods in the past three years. The subsidiary paid a cash penalty of $500,000 to the District and paid an additional $1 million to fund a supplemental environmental project that is expected to further reduce the facility's emissions.

In November 2017, Chevron initiated a contractual dispute resolution process regarding audit claims alleging that it has been underallocated NGLs by approximately $200 million and overcharged for power by $50 million at the Elk Hills field. Under the applicable dispute resolution procedures, the parties are to engage in negotiations, mediation, and, if necessary, binding arbitration. After an extensive review of these claims, including review by third-party accounting experts with respect to the NGL claim, we concluded and continue to believe these claims are without merit. Based on our review, we believe that we have in fact overallocated oil, NGLs and gas to Chevron and intend to take action to seek an adjustment in our favor.

For additional information regarding legal proceedings, see *Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Lawsuits, Claims, Commitments and Contingencies* and in *Item 8—Financial Statements and Supplementary Data—Note 7 Lawsuits, Claims, Commitments and Contingencies*.

ITEM 4 MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS

Executive officers are appointed annually by the Board of Directors. The following table sets forth our current executive officers:

Name	Positions Held with CRC and Predecessor and Employment History	Age at February 26, 2018
Todd A. Stevens	President, Chief Executive Officer and Director since 2014; Occidental Petroleum Corporation Vice President—Corporate Development 2012 to 2014; Oxy Oil & Gas Vice President—California Operations 2008 to 2012; Occidental Petroleum Corporation Vice President—Acquisitions and Corporate Finance 2004 to 2012.	51
Marshall D. Smith	Senior Executive Vice President and Chief Financial Officer since 2014; Ultra Petroleum Corporation Senior Vice President and Chief Financial Officer 2011 to 2014; Ultra Petroleum Corporation Chief Financial Officer 2005 to 2014.	58
Shawn M. Kerns	Executive Vice President—Operations and Engineering—2018; Executive Vice President—Corporate Development 2014 to 2018; Vintage Production California President and General Manager 2012 to 2014; Occidental of Elk Hills General Manager 2010 to 2012; Occidental of Elk Hills Asset Development Manager 2008 to 2010.	47
Francisco J. Leon	Executive Vice President—Corporate Development and Strategic Planning—2018; Vice President—Portfolio Management and Strategic Planning 2014 to 2018; Occidental Director—Portfolio Management 2012 to 2014; Occidental Director of Corporate Development and M&A 2010 to 2012; Occidental Manager of Business Development 2008 to 2010.	41
Roy Pineci	Executive Vice President—Finance since 2014; Occidental Vice President and Controller 2008 to 2014; Occidental Oil and Gas Senior Vice President 2007 to 2008.	55
Michael L. Preston	Executive Vice President, General Counsel and Corporate Secretary since 2014; Occidental Oil and Gas Vice President and General Counsel 2001 to 2014.	53
Charles F. Weiss	Executive Vice President—Public Affairs since 2014; Occidental Vice President, Health, Environment and Safety 2007 to 2014.	54
Darren Williams	Executive Vice President—Operations and Geoscience—2018; Executive Vice President—Exploration 2014 to 2018; Marathon Upstream Gabon Limited President and Africa Exploration Manager 2013 to 2014; Marathon Oil Oklahoma Subsurface Manager 2010 to 2013; Marathon Oil Gulf of Mexico Exploration and Appraisal Manager 2008 to 2010.	46

PART II

ITEM 5 MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information for Common Stock

Our common stock began trading "regular way" on the New York Stock Exchange (NYSE) under the symbol "CRC" on December 1, 2014. Prior to that date there was no public trading market for our common stock. On May 31, 2016, we completed a reverse stock split using a ratio of one share of common stock for every ten shares then outstanding. All share-related information is presented on a split-adjusted basis.

The following schedule sets forth the high and low sales price per share of our common stock as reported on the NYSE for the periods indicated:

	Stock Price			
	2017		2016	
	High	Low	High	Low
First Quarter	$ 23.42	$ 12.30	$ 23.30	$ 2.81
Second Quarter	$ 16.25	$ 7.73	$ 25.50	$ 9.20
Third Quarter	$ 11.31	$ 6.47	$ 15.18	$ 8.79
Fourth Quarter	$ 20.19	$ 8.84	$ 21.97	$ 9.84

Holders of Record

Our common stock was held by approximately 21,400 stockholders of record at December 31, 2017.

Dividend Policy

In 2017 and 2016, no dividends were paid. In 2015, we paid quarterly dividends of $0.10 per share for the first three quarters of the year.

In November 2015, our Board of Directors suspended the payment of any dividends. This decision remains consistent with the Company's broader initiatives to contain costs and strengthen the balance sheet. The payment of future dividends, if any, will be at the discretion of our Board of Directors and will depend upon, among other things, our financial condition, results of operations, capital requirements and development expenditures, future business prospects and any restrictions imposed by future debt instruments. See *Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Agreements* for a description of limitations on paying dividends in our credit facilities.

Securities Authorized for Issuance Under Equity Compensation Plans

Our stock-based compensation plans were approved by our stockholders at the May 2016 annual meeting. A description of the plans can be found in *Item 8—Financial Statements and Supplementary Data—Note 10 Stock Compensation*. The aggregate number of shares of our common stock authorized for issuance under stock-based compensation plans for our employees and non-employee directors is 5.7 million, of which approximately 4.3 million had been issued or reserved through December 31, 2017.

The following is a summary of the securities available for issuance under such plans as of December 31, 2017:

a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	b) Weighted-average exercise price of outstanding options, warrants and rights	c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities in column (a))
2,906,623	$69.95 (1)	1,414,162 (2)

(1) Exercise price applies only to approximately 1.1 million options included in column (a) and not to any other awards.
(2) Includes 306,154 shares available under our 2014 Employee Stock Purchase Plan (ESPP) for purchase at 85% of the lower of the market price at (i) the beginning of a quarter and (ii) the end of a quarter.

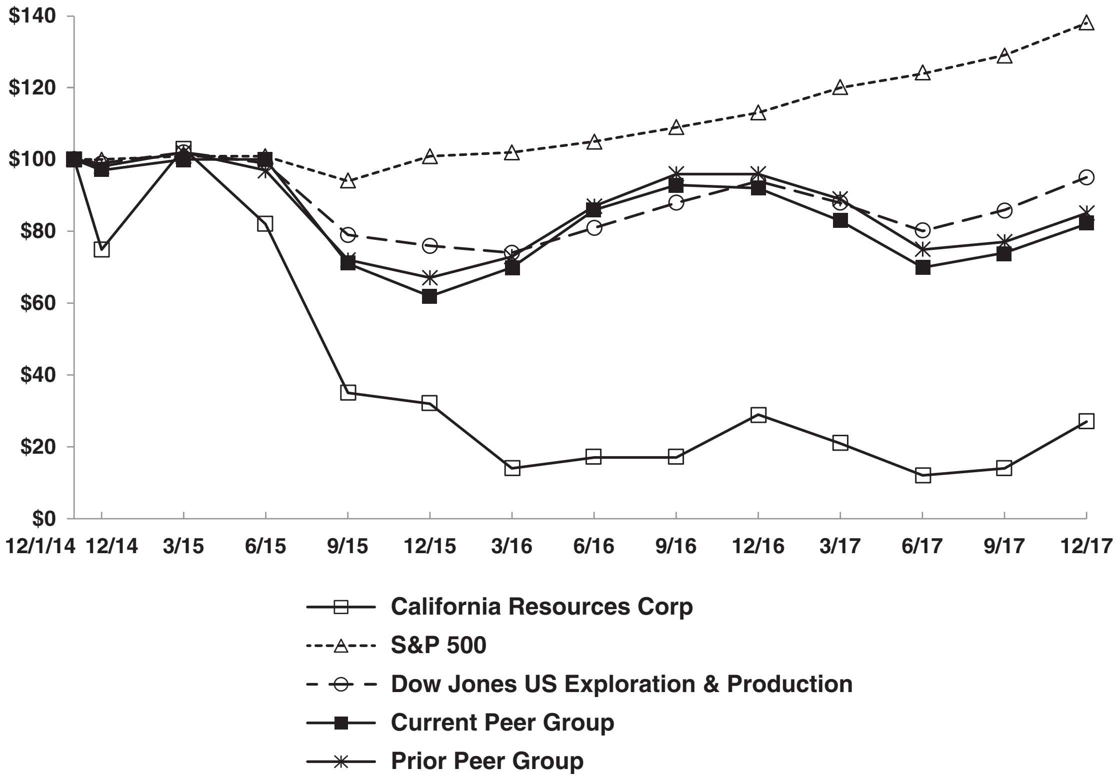
Performance Graph

The following graph compares the cumulative total return to stockholders on our common stock relative to the cumulative total returns of the S&P 500 and Dow Jones U.S. Exploration and Production indexes and our peer groups (with reinvestment of all dividends). The graph assumes that on December 1, 2014, the date our common stock began trading on the NYSE, $100 was invested in our common stock, in each index and in each of the peer group companies' common stock weighted by their relative market values within the peer group, and that all dividends were reinvested. The returns shown are based on historical results and are not intended to suggest future performance.

Our peer group changed in 2017 from prior years. Our current peer group consists of Cabot Oil and Gas Corporation; Cimarex Energy Co.; Concho Resources Inc.; Denbury Resources Inc.; Energen Corporation; EP Energy Corporation; Murphy Oil Corporation; Newfield Exploration Company; Oasis Petroleum Inc.; Parsley Energy, Inc.; QEP Resources, Inc.; Range Resources Corporation; SM Energy Company; Whiting Petroleum Corporation and WPX Energy, Inc. Previously, our peer group also included Noble Energy Inc. and Pioneer Natural Resources Co.

PERFORMANCE GRAPH*

Among California Resources Corp, the S&P 500 Index, the Dow Jones US Exploration & Production Index, Prior Peer Group and Current Peer Group



	2014		2015				2016				2017			
	12/1	12/31	3/31	6/30	9/30	12/31	3/31	6/30	9/30	12/31	3/31	6/30	9/30	12/31
California Resources Corp	$ 100	$ 75	$ 103	$ 82	$ 35	$ 32	$ 14	$ 17	$ 17	$ 29	$ 21	$ 12	$ 14	$ 27
S&P 500	100	100	101	101	94	101	102	105	109	113	120	124	129	138
Dow Jones US Exploration & Production	100	99	102	99	79	76	74	81	88	94	88	80	86	95
Current Peer Group	100	97	100	100	71	62	70	86	93	92	83	70	74	82
Prior Peer Group	100	98	102	97	72	67	73	87	96	96	89	75	77	85

* This performance graph shall not be deemed “soliciting material” or to be “filed” with the SEC for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liabilities under that Section, and shall not be deemed to be incorporated by reference into any filing of CRC under the Securities Act of 1933, as amended, or the Exchange Act except to the extent that we specifically request it be treated as soliciting material or specifically incorporate it by reference.

ITEM 6 SELECTED FINANCIAL DATA

Prior to the Spin-off on November 30, 2014, financial data was derived from Occidental's California oil and gas exploration and production operations and related assets, liabilities and obligations (California business), which we assumed with the Spin-off. All financial information presented after the Spin-off represents our stand-alone consolidated results of operations, financial position and cash flows. Accordingly:

- The selected statement of operations and cash flows data for the years ended December 31, 2017, 2016 and 2015 consist of our stand-alone consolidated results post Spin-off. For the year ended December 31, 2014 the statement of operations and cash flows data includes the consolidated results for the month ended December 31, 2014 and the combined results of the California business prior to the Spin-off. The selected statement of operations and cash flow data for the year ended December 31, 2013 consists entirely of the combined results of the California business.
- The selected balance sheet data at December 31, 2017, 2016, 2015 and 2014 consists of our stand-alone consolidated balances, while the selected balance sheet data at December 31, 2013 consists of the combined balances of the California business.

All share-related information is presented on a split-adjusted basis.

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(in millions, except for per share data)				
Statement of Operations Data					
Revenues	$ 2,006	$ 1,547	$ 2,403	$ 4,173	$ 4,284
(Loss) income before income taxes	$ (262)	$ 201	$ (5,476)	$ (2,421)	$ 1,447
Net (loss) income attributable to common stock	$ (266)	$ 279	$ (3,554)	$ (1,434)	$ 869
Per common share					
Basic and diluted	$ (6.26)	$ 6.76	$ (92.79)	$ (37.54)	$ 22.38
Statement of Cash Flows Data					
Net cash provided by operating activities	$ 248	$ 130	$ 403	$ 2,371	$ 2,476
Capital investments	$ (371)	$ (75)	$ (401)	$ (2,089)	$ (1,669)
Acquisitions and other	$ (2)	$ —	$ (151)	$ (292)	$ (44)
Net (repayments) borrowings and related costs	$ (18)	$ (73)	$ 356	$ 6,290	$ —
Contribution from noncontrolling interest, net	$ 98	$ —	$ —	$ —	$ —
Spin-off related dividends to Occidental	$ —	$ —	$ —	$ (6,000)	$ —
Distributions to Occidental, net	$ —	$ —	$ —	$ (335)	$ (763)
Dividends per Common Share	$ —	$ —	$ 0.30	$ —	$ —

	As of December 31,				
	2017	2016	2015	2014	2013
	(in millions)				
Balance Sheet Data					
Total current assets	$ 483	$ 425	$ 438	$ 701	$ 254
Property, plant and equipment, net	$ 5,696	$ 5,885	$ 6,312	$ 11,685	$ 14,008
Total assets	$ 6,207	$ 6,354	$ 7,053	$ 12,429	$ 14,297
Current maturities of long-term debt	$ —	$ 100	$ 100	$ —	$ —
Total current liabilities	$ 732	$ 726	$ 605	$ 922	$ 689
Long-term debt—principal amount	$ 5,306	$ 5,168	$ 6,043	$ 6,360	$ —
Deferred gain and issuance costs, net	$ 287	$ 397	$ 491	$ (68)	$ —
Other long-term liabilities	$ 602	$ 620	$ 830	$ 549	$ 497
Equity attributable to common stock	$ (814)	$ (557)	$ (916)	$ 2,611	$ 9,989

The selected financial data presented above should be read in conjunction with *Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations* and the consolidated financial statements and accompanying notes included elsewhere in this Form 10-K.

ITEM 7 MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

We are an independent oil and natural gas exploration and production company operating properties within California. We are incorporated in Delaware and became a publicly traded company on December 1, 2014. Except when the context otherwise requires or where otherwise indicated, all references to ''CRC,'' the ''Company,'' ''we,'' ''us'' and ''our'' refer to California Resources Corporation and its subsidiaries.

Basis of Presentation and Certain Factors Affecting Comparability

All financial information presented consists of our consolidated results of operations, financial position and cash flows. The assets and liabilities in the consolidated financial statements are presented on a historical cost basis. We have eliminated all of our significant intercompany transactions and accounts. We account for our share of oil and gas exploration and production ventures, in which we have a direct working interest, by reporting our proportionate share of assets, liabilities, revenues, costs and cash flows within the relevant lines on the balance sheets and statements of operations and cash flows.

On May 31, 2016 we completed a reverse stock split using a ratio of one share of common stock for every ten shares then outstanding. Share and per share amounts included in this report reflect this stock split for all periods presented.

Business Environment and Industry Outlook

Our operating results and those of the oil and gas industry as a whole are heavily influenced by commodity prices. Oil and gas prices and differentials may fluctuate significantly, generally as a result of market-related variables such as consumption patterns; inventory levels; global and local economic conditions; the actions of the Organization of the Petroleum Exporting Countries (OPEC) and other producers and governments; actual or threatened disruptions in production, refining and processing; currency exchange rates; worldwide drilling and exploration activities; the effects of conservation, weather, geophysical and technical limitations; technological advances; transportation and storage capacity; bottlenecks and costs in producing areas; alternative energy sources; regional market conditions; and other matters affecting the supply and demand dynamics for our products; as well as the effect of changes in these variables on market perceptions. These and other factors make it impossible to predict realized prices reliably.

Much of the global exploration and production industry has been challenged in the low-commodity price cycle in recent years, putting pressure on the industry's ability to generate positive cash flow and access capital. Global oil prices were higher in 2017 compared to 2016. Natural gas liquids (NGLs) prices have improved relative to crude oil prices throughout 2017 due to tighter domestic supplies, the strength of exports and higher contract prices on natural gasoline. Full year average natural gas prices in the U.S. were higher in 2017 than in 2016 due to lower production and higher demand.

The following table presents the average daily Brent, WTI and NYMEX prices for each of the years ended December 31, 2017, 2016 and 2015:

	2017	2016	2015
Brent oil ($/Bbl)	$ 54.82	$ 45.04	$ 53.64
WTI oil ($/Bbl)	$ 50.95	$ 43.32	$ 48.80
NYMEX gas ($/MMBtu)	$ 3.09	$ 2.42	$ 2.75

We currently sell all of our crude oil into the California refining markets, which we believe have offered relatively favorable pricing compared to other U.S. regions for similar grades. California is heavily reliant on imported sources of energy, with approximately 72% of the oil consumed in 2017 imported from outside the state. A vast majority of the imported oil arrives via supertanker, mostly from foreign locations. As a result, California refiners have typically purchased crude oil at international waterborne-based prices. We believe that the limited crude transportation infrastructure from other parts of the U.S. to California will continue to contribute to higher realizations than most other U.S. oil markets for comparable grades. Additionally, our differentials improved against Brent during 2017, as a result of an increase in the benchmark prices to North America from the Middle East and higher-than-expected demand in Asia. The improvement continued into the early part of 2018.

Prices and differentials for NGLs are related to the supply and demand for the products making up these liquids. Some of them more typically correlate to the price of oil while others are affected by natural gas prices as well as the demand for certain chemical products for which they are used as feedstock. In addition, infrastructure constraints magnify pricing volatility.

Natural gas prices and differentials are strongly affected by local market fundamentals, as well as availability of transportation capacity from producing areas. Capacity influences prices because California imports about 90% of its natural gas from other states and Canada. As a result, we typically enjoy favorable pricing relative to out-of-state producers since we can deliver our gas for lower transportation costs. Due to our much lower natural gas production compared to our oil production, the changes in natural gas prices have a smaller impact on our operating results.

In addition to selling natural gas, we also use gas for our steamfloods and power generation. As a result, the positive impact of higher natural gas prices is partially offset by higher operating costs but higher prices still have a net positive effect on our operating results. Conversely, lower natural gas prices generally have a net negative effect on our results, but lower the cost of our steamflood projects and power generation. In 2017, greater availability of hydroelectricity in California due to higher-than-normal rainfalls caused downward pressure on natural gas prices, reducing our realized prices as a percentage of the NYMEX index, and gas storage capacity disruptions caused seasonal price volatility.

Our earnings are also affected by the performance of our processing and power generation assets. We process our wet gas to extract NGLs and other natural gas byproducts. We then deliver dry gas to pipelines and separately sell the NGLs. The efficiency with which we extract liquids from the wet gas stream affects our operating results. Additionally, we use part of the electricity from the Elk Hills power plant to reduce operating costs at Elk Hills and nearby fields and increase reliability. The remaining electricity is sold to the grid and a utility under a power purchase and sales agreement that includes a capacity payment. The price obtained for excess power impacts our earnings but generally by an insignificant amount.

We opportunistically seek strategic hedging transactions to help protect our cash flows, margins and capital investment program from the cyclical nature of commodity prices and to improve our ability to comply with our debt covenants. We can give no assurances that our hedges will be adequate to accomplish our objectives. Unless otherwise indicated, we use the term “hedge” to describe derivative instruments that are designed to achieve our hedging program goals, even though they are not necessarily accounted for as cash-flow or fair-value hedges.

We respond to economic conditions by adjusting the amount and allocation of our capital program, aligning the size of our workforce with our level of activity, continuing to improve efficiencies and finding cost savings. The reductions in our capital program in 2015 and 2016 negatively impacted our 2017 production levels. With our increased capital program in 2017, our oil production flattened. With our 2018 program we expect to achieve sustained oil production growth and end the year with higher production than the beginning of the year. Volatility in oil prices may materially affect the quantities of oil and gas reserves we can economically produce over the longer term.

Seasonality

While certain aspects of our operations are affected by seasonal factors, such as electricity costs, overall, seasonality is not a material driver of changes in our earnings during the year.

Joint Ventures

Exploration and Development Joint Ventures

In line with our strategy, we have entered into a number of joint ventures (JVs) where our partners carry all or substantially all of our exploration and development costs. These JVs allow us to continue to develop our assets while providing us with financial flexibility and immediate production benefit.

In February 2017, we entered into a JV with Benefit Street Partners (BSP) where BSP will contribute up to $250 million, subject to agreement of the parties, in exchange for a preferred interest in the JV (BSP JV). The funds contributed by BSP are designated to be used to develop certain of our oil and gas properties. We contributed a net profits interest (NPI) in existing and future cash flow from such properties in exchange for a common interest in the JV. BSP is entitled to preferential distributions and, if BSP receives cash distributions equal to a predetermined threshold, the preferred interest is automatically redeemed in full with no additional payment. BSP funded two $50 million tranches in March and July 2017, which were net of a $2 million issuance fee. The $98 million net proceeds were used to fund capital investments of $96 million and the remainder for hedging activities. Proceeds from the NPI are used by the BSP JV to (1) pay quarterly minimum distributions to BSP, (2) pay for development costs within the project area, upon mutual agreement between members, and (3) make distributions to BSP until the predetermined threshold is achieved.

In April 2017, we entered into a JV with Macquarie Infrastructure and Real Assets Inc. (MIRA) under which MIRA will invest up to $300 million, subject to agreement of the parties, to develop certain of our oil and gas properties in exchange for a 90% working interest in the related properties (MIRA JV). MIRA will fund 100% of the development cost of such properties. Our 10% working interest reverts to 75% if MIRA receives cash distributions equal to a predetermined threshold return. MIRA initially committed $160 million, which is intended to be invested over two years. Of the committed amount, MIRA contributed $58 million for drilling projects in 2017, with additional funding of up to $96 million expected in 2018.

Our consolidated results reflect the full operations of our BSP JV, with BSP's share of net income and stockholders' equity being shown separately as a noncontrolling interest in the accompanying consolidated statements of operations and consolidated balance sheets, respectively. Our consolidated results reflect only our working interest share in our MIRA JV.

We also entered into several other development and exploration JVs in which our JV partners have committed capital of approximately $30 million. These JVs could provide more than $75 million in capital if certain milestones are met.

Midstream Joint Venture

In February 2018, we entered into a midstream JV with ECR Corporate Holdings L.P. (ECR), a portfolio company of Ares. This Ares JV holds the Elk Hills power plant, a 550 megawatt natural gas fired power plant, and the 200 million cubic foot per day cryogenic gas processing plant. Through one of our wholly owned subsidiaries, we hold 50% of the Class A common interest and 95.25% of the Class C common interest in the Ares JV. ECR holds 50% of the Class A common interest, 100% of the Class B preferred interest and 4.75% of the Class C common interest in the Ares JV. The proceeds will be utilized for our highest value projects, including but not limited to, acquisitions, investing in our business or buying our debt. At closing, in accordance with the terms of our credit agreement, we used $297 million of the $747 million in net proceeds to pay off the then outstanding balance of our 2014 Revolving Credit Facility.

We will consolidate the Ares JV in our financial statements and reflect the Class A common interest and Class B preferred interest as noncontrolling interest in mezzanine equity and the Class C common interest in equity on our balance sheet. Net income allocable to ECR will be reported as income attributable to noncontrolling interest. Distributions will be paid to the preferred interest on a priority basis with the remaining cash distributed pro-rata to the common interests.

Private Placement

In February 2018 and in connection with the formation of the Ares JV, an Ares-led investor group purchased approximately 2.3 million shares of our common stock in a private placement for an aggregate purchase price of $50 million.

Acquisitions and Divestitures

In February 2017, we divested non-core assets resulting in $32 million of proceeds and a $21 million gain. During the year ended December 31, 2016, we divested non-core assets resulting in $20 million of proceeds and a $30 million gain. During the year ended December 31, 2015, we paid approximately $140 million to acquire certain producing and non-producing oil and gas properties, primarily in the San Joaquin basin.

Income Taxes

On December 22, 2017, the Tax Cuts and Jobs Act (the Tax Act) was enacted. The Tax Act includes significant changes to U.S. income tax and related laws. In addition to the reduction in the top corporate tax rate, other provisions of the Tax Act include, but are not limited to, fully expensing the cost of acquired qualified property, subject to certain phase-out provisions, and limiting the interest expense deduction. We evaluated the provisions of the Tax Act, most of which are effective January 1, 2018, and determined that because of our tax loss and valuation allowance position there is no net current impact in our financial statements. Over the long term, the provisions are expected to be favorable to us and should result in the deferral of cash tax payments from when they otherwise would have been due once we begin to generate taxable income.

The following table sets forth our pre- and after-tax (loss) income and income tax amounts:

	For the years ended December 31,		
	2017	**2016**	**2015**
		(in millions)	
Pre-tax (loss) income	$ (262)	$ 201	$ (5,476)
Income tax benefit	—	78	1,922
Net (loss) income	(262)	279	(3,554)

We did not make United States federal and state income tax payments in 2017, 2016 or 2015 due to the tax losses we incurred.

Total income tax expense (benefit) differs from the amounts computed by applying the U.S. federal income tax rate to pre-tax income (loss) as follows:

	For the years ended December 31,		
	2017	2016	2015
U.S. federal statutory tax rate	(35)%	35%	(35) %
State income taxes, net	(6)	6	(5)
Decrease in U.S. federal corporate tax rate	91	—	—
Changes in tax attributes, net	(19)	—	—
Cancellation of debt income, net	—	(275)	—
Stock-based compensation, net	1	2	—
Valuation allowance, net	(33)	192	5
Other	1	1	—
Effective tax rate	—%	(39)%	(35)%

During 2017, our effective tax rate differed from the statutory tax rate of 35% due to (1) a 91% decrease related to a one-time adjustment of $240 million for the remeasurement of our net deferred tax asset as a result of the Tax Act, (2) a 19% increase related to EOR tax credits, marginal well tax credits and other items, and (3) a 6% increase related to state taxes. All of these items resulted in a corresponding change to our valuation allowance, increasing our effective tax rate by 33%, because it is not more-likely-than-not that our net deferred tax asset is realizable.

In the first quarter of 2016, we reduced our valuation allowance due to our evaluation of our assets and liabilities at the time of our 2015 debt exchange, which generated $1.4 billion of cancellation of debt income (CODI) for tax purposes. Our evaluation indicated that our liabilities exceeded the value of our assets, both calculated in accordance with tax rules, enabling us to move the liability related to CODI to deferred tax liabilities. The resulting increase of our deferred tax liabilities that could be offset against deferred tax assets caused an $82 million reduction in the valuation allowance and resulted in a benefit of $78 million, net of $4 million in state tax. During the rest of 2016, we increased the valuation allowance by $480 million, which resulted in a net increase of the allowance by $398 million for the year. The net change in the valuation allowance had the effect of increasing our provision by $384 million, after $14 million in state taxes, which increased our effective tax rate by 192%. We concluded, on a more-likely-than-not basis, that we could not realize any of the deferred tax assets generated during 2016.

Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit use of existing deferred tax assets. A significant piece of evidence evaluated is a history of operating losses. Such evidence limits our ability to consider other evidence such as projections for growth. As of December 31, 2017, we concluded that we could not realize, on a more-likely-than-not basis, any of our deferred tax assets and there is not sufficient evidence to support the reversal of all or any portion of this allowance. Given our recent and anticipated future earnings trends, we do not believe any of the valuation allowance will be released within the next 12 months. The amount of the deferred tax assets considered realizable could however be adjusted if estimates or amounts of deferred tax liabilities change.

Cancellation of debt income

As a result of our 2015, 2016 and 2017 debt transactions and amendments, we generated CODI of $1.4 billion, $1.3 billion and $13 million, respectively ($2.7 billion in the aggregate), for both U.S. federal and California state tax purposes. These respective amounts were excluded from taxable income because we determined, in 2016, that our liabilities exceeded the value of our assets for tax purposes immediately prior to each of the deleveraging transactions. In exchange for this exclusion, tax rules require us to reduce the tax basis of our assets. Accordingly, we have reduced our net operating losses and the basis of property, plant and equipment by $1.2 billion for U.S. federal tax purposes and $1.9 billion for California tax purposes. We were not required to make any further reductions in those assets because, beyond this point, our liabilities would have exceeded the tax basis of our assets. Accordingly, any tax liability attributable to the remaining approximately $1.5 billion of federal and $800 million of California CODI was relieved without any future tax liability, which reduced our 2016 effective rate by 275%.

Operations

We conduct our operations on properties that we hold through fee interests, mineral leases and other contractual arrangements. We believe we are the largest private oil and natural gas mineral acreage holder in California, with interests in approximately 2.3 million net mineral acres, approximately 60% of which we hold in fee and approximately 15% of which is held by production. Our oil and gas leases have a primary term ranging from one to ten years, which is extended through the end of production once it commences. We also own a network of strategically placed infrastructure that is integrated with, and complementary to, our operations, including gas plants, oil and gas gathering systems, power plants and other related assets, which we use to maximize the value generated from our production.

Our share of production and reserves from operations in the Wilmington field is subject to contractual arrangements similar to production-sharing contracts (PSCs) that are in effect through the economic life of the assets. Under such contracts we are obligated to fund all capital and production costs. We record a share of production and reserves to recover a portion of such capital and production costs and an additional share for profit. Our portion of the production represents volumes: (i) to recover our partners' share of capital and production costs that we incur on their behalf, (ii) for our share of contractually defined base production, and (iii) for our share of remaining production thereafter. We recover our share of capital and production costs, and generate returns, through our defined share of production from (ii) and (iii) above. These contracts do not transfer any right of ownership to us and reserves reported from these arrangements are based on our economic interest as defined in the contracts. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline assuming comparable capital investment and production costs. However, our net economic benefit is greater when product prices are higher. The contracts represented approximately 20% of our production for the year ended December 31, 2017.

In addition, in line with industry practice for reporting PSC-type contracts, we report 100% of operating costs under the PSCs in our consolidated statements of operations as opposed to reporting only our share of those costs. We report the proceeds from production designed to recover our partners' share of such costs (cost recovery) in our revenues. Our reported production volumes reflect only our share of the total volumes produced, including cost recovery, which is less than the total volumes produced under the PSCs. This difference in reporting full operating costs but only our net share of production inflates our operating costs per barrel, with an equal corresponding increase in revenues, with no effect on our net results.

With our significant land holding in California, we have undertaken new initiatives to unlock additional value from our real estate. Our developing real estate initiatives include renewable energy opportunities such as solar energy projects; agricultural activities such as the production of fruits and nuts; and commercial real estate. We are also exploring carbon dioxide capture and storage projects and reclaimed water opportunities.

Production and Prices

The following table sets forth our average production volumes of oil, NGLs and natural gas per day for the years ended December 31, 2017, 2016 and 2015:

	2017	2016	2015
Oil (MBbl/d)			
San Joaquin Basin	52	57	64
Los Angeles Basin	27	29	34
Ventura Basin	4	5	6
Sacramento Basin	—	—	—
Total	83	91	104
NGLs (MBbl/d)			
San Joaquin Basin	15	15	17
Los Angeles Basin	—	—	—
Ventura Basin	1	1	1
Sacramento Basin	—	—	—
Total	16	16	18
Natural gas (MMcf/d)			
San Joaquin Basin	140	150	172
Los Angeles Basin	1	3	2
Ventura Basin	8	8	11
Sacramento Basin	33	36	44
Total	182	197	229
Total Production (MBoe/d)[(a)]	129	140	160

Note: MBbl/d refers to thousands of barrels per day; MMcf/d refers to millions of cubic feet per day; MBoe/d refers to thousands of barrels of oil equivalent per day.

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

The following table sets forth the average realized prices for our products for the years ended December 31, 2017, 2016 and 2015:

	2017	2016	2015
Oil prices with hedge ($ per Bbl)	$ 51.24	$ 42.01	$ 49.19
Oil prices without hedge ($ per Bbl)	$ 51.47	$ 39.72	$ 47.15
NGLs prices ($ per Bbl)	$ 35.76	$ 22.39	$ 19.62
Natural gas prices ($ per Mcf)[(a)]	$ 2.67	$ 2.28	$ 2.66

(a) For 2015, the average realized price of natural gas includes the effect of hedges.

The following table presents our average price realizations as a percentage of Brent, WTI and NYMEX for the years ended December 31, 2017, 2016 and 2015:

	2017	2016	2015
Oil with hedge as a percentage of Brent	93%	93%	92%
Oil with hedge as a percentage of WTI	101%	97%	101%
Oil without hedge as a percentage of Brent	94%	88%	88%
Oil without hedge as a percentage of WTI	101%	92%	97%
NGLs as a percentage of Brent	65%	50%	37%
NGLs as a percentage of WTI	70%	52%	40%
Natural gas as a percentage of NYMEX[(a)]	86%	94%	97%

(a) For 2015, the average realized price of natural gas as a percentage of NYMEX includes the effect of hedges.

Balance Sheet Analysis

The changes in our balance sheet as of December 31, 2017 and 2016, are discussed below:

	2017	2016
	(in millions)	
Cash	$ 20	$ 12
Trade receivables	$ 277	$ 232
Inventories	$ 56	$ 58
Other current assets, net	$ 130	$ 123
Property, plant and equipment, net	$ 5,696	$ 5,885
Other assets	$ 28	$ 44
Current maturities of long-term debt	$ —	$ 100
Accounts payable	$ 257	$ 219
Accrued liabilities	$ 475	$ 407
Long-term debt—principal amount	$ 5,306	$ 5,168
Deferred gain and financing costs, net	$ 287	$ 397
Other long-term liabilities	$ 602	$ 620
Equity attributable to common stock	$ (814)	$ (557)
Equity attributable to noncontrolling interest	$ 94	$ —

Cash at December 31, 2017 included approximately $5 million that is restricted under our BSP JV agreement for distributions to BSP unless otherwise mutually agreed to by the parties. See the *Liquidity and Capital Resources* section below for discussion of changes in our cash.

The increase in trade receivables was largely the result of higher year-end prices partially offset by lower production volumes in 2017 compared to 2016. The decrease in property, plant and equipment reflected depreciation, depletion and amortization (DD&A) for the period, partially offset by capital investments. The decrease in other assets was primarily due to changes in the fair value of our long-term derivative assets.

The reduction in current maturities of long-term debt was the result of the repayment of the remaining balance on our 2014 Term Loan in November 2017. The increase in accounts payable reflected higher capital investments in 2017 compared to 2016. The increase in accrued liabilities was primarily due to higher derivative and greenhouse gas obligations. The small increase in our debt, including the current maturities of our long-term debt, reflected the proceeds from the $1.3 billion credit agreement entered into in November 2017, net of transaction costs, partially offset by early repayment of our 2014 Term Loan, net paydown on our 2014 Revolving Credit Facility and repurchases of our Senior Notes. See the *Liquidity and Capital Resources* section below for further discussion on our debt-related activities. The decrease in deferred gain and issuance costs, net, reflected the amortization of deferred gains, partially offset by new deferred transaction costs related to our debt transactions and the amortization of deferred issuance costs. The decrease in other long-term liabilities reflected changes in the fair value of our derivative liabilities, partially offset by an increase in equity and deferred compensation obligations. The decrease in equity attributable to common stock primarily reflected the net loss for the period. Equity attributable to noncontrolling interest primarily reflected contributions from BSP, partially offset by distributions to BSP.

Statement of Operations Analysis

Results of Oil and Gas Operations

The following represents key operating data for our oil and gas operations, excluding certain corporate items, on a per Boe basis for the years ended December 31, 2017, 2016 and 2015:

	2017	2016	2015
Production costs	$ 18.64	$ 15.61	$ 16.30
Production costs, excluding effects of PSC contracts[a]	$ 17.48	$ 14.69	$ 15.58
Field general and administrative expenses[b]	$ 0.82	$ 0.84	$ 1.31
Field general and administrative expenses, adjusted[c]	$ 0.72	$ 0.72	$ 1.00
Field other operating expenses[b]	$ 0.66	$ 1.02	$ 1.78
Field other operating expenses, adjusted[d]	$ 0.56	$ 0.67	$ 0.36
Field depreciation, depletion and amortization[b]	$ 10.85	$ 10.28	$ 16.72
Field taxes other than on income[b]	$ 2.34	$ 2.36	$ 2.67

(a) As described in the Operations section, the reporting of our PSC-like contracts creates a difference between reported production costs, which are for the full field, and reported volumes, which are only our net share, inflating the per barrel production costs. The amounts represent the production costs for the company after adjusting for this difference.

(b) Amounts exclude corporate charges.

(c) Amounts exclude corporate charges. Amounts also exclude unusual and infrequent charges related to severance and early retirement costs associated with field personnel totaling $0.10 per Boe, $0.12 per Boe and $0.31 per Boe, for 2017, 2016 and 2015, respectively.

(d) Amounts exclude corporate charges. For 2017, the amount excludes net unusual and infrequent charges of $0.10 primarily related to rig termination expenses partially offset by property tax refunds, recovery of amounts due from joint interest partners and other items. For 2016, the amount excludes net unusual and infrequent gains of $0.35 that include refunds partially offset by plant turnaround charges and other items. For 2015, the amount excludes charges related to the write-down of certain assets and rig termination charges of $1.42 per Boe.

Consolidated Results of Operations

The following represents key operating data for consolidated operations for the years ended December 31, 2017, 2016 and 2015:

	2017	2016	2015
		(in millions)	
Oil and gas net sales	$1,936	$ 1,621	$ 2,134
Net derivative (losses) gains	(90)	(206)	133
Other revenue	160	132	136
Production costs	(876)	(800)	(951)
General and administrative expenses	(259)	(248)	(354)
Depreciation, depletion and amortization	(544)	(559)	(1,004)
Asset impairments	—	—	(4,852)
Taxes other than on income	(136)	(144)	(180)
Exploration expense	(22)	(23)	(36)
Other expenses, net	(106)	(79)	(168)
Interest and debt expense, net	(343)	(328)	(326)
Net gains on early extinguishment of debt	4	805	20
Gains on asset divestitures	21	30	—
Other non-operating expense	(7)	—	(28)
(Loss) income before income taxes	(262)	201	(5,476)
Income tax benefit	—	78	1,922
Net (loss) income	(262)	279	(3,554)
Net income attributable to noncontrolling interest	$ (4)	$ —	$ —
Net (loss) income attributable to common stock	$ (266)	$ 279	$(3,554)
Adjusted net loss	$ (187)	$ (317)	$ (311)
Adjusted EBITDAX	$ 761	$ 616	$ 906
Effective tax rate	— %	(39)%	(35)%

Non-GAAP Financial Measures

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 loss and adjusted general and administrative expenses, both of 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 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.

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

	2017	2016	2015
	(in millions, except share data)		
Net (loss) income attributable to common stock	$ (266)	$ 279	$ (3,554)
Unusual and infrequent items:			
Non-cash derivative losses (gains), excluding noncontrolling interest	78	283	(52)
Early retirement, severance and other costs	5	20	67
Net gains on early extinguishment of debt	(4)	(805)	(20)
Gains on asset divestitures	(21)	(30)	—
Asset impairments	—	—	4,852
Write-down of certain assets	—	—	71
Debt issuance costs	—	—	28
Other	21	(13)	11
Total unusual and infrequent items	79	(545)	4,957
Deferred debt issuance costs write-off	—	12	—
Reversal of valuation allowance for deferred tax assets(a)	—	(63)	294
Tax effects of these items	—	—	(2,008)
Adjusted net loss	$ (187)	$ (317)	$ (311)
Net (loss) income attributable to common stock per diluted share	$ (6.26)	$ 6.76	$ (92.79)
Adjusted net loss per diluted share	$ (4.40)	$ (7.85)	$ (8.12)

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

The following table presents a reconciliation of the GAAP financial measure of net (loss) income attributable to common stock to the non-GAAP financial measure of Adjusted EBITDAX:

	2017	2016	2015
	(in millions)		
Net (loss) income attributable to common stock	$ (266)	$ 279	$ (3,554)
Interest and debt expense, net	343	328	326
Income tax benefit	—	(78)	(1,922)
Depreciation, depletion and amortization, excluding noncontrolling interest	535	559	1,004
Exploration expense	22	23	36
Unusual and infrequent items	79	(545)	4,957
Other non-cash items	48	50	59
Adjusted EBITDAX	$ 761	$ 616	$ 906

The following table presents the components of our net derivative (losses) gains:

	2017	2016	2015
		(in millions)	
Non-cash derivative (losses) gains, excluding noncontrolling interest	$ (78)	$ (283)	$ 52
Non-cash derivative losses for noncontrolling interest	(5)	—	—
Cash (payments) proceeds from settled derivatives	(7)	77	81
Net derivative (losses) gains	$ (90)	$ (206)	$ 133

The following table presents the reconciliation of our company-wide GAAP financial measure of general and administrative expenses to the non-GAAP financial measure of adjusted general and administrative expenses:

	2017	2016	2015
		(in millions)	
General and administrative expenses	$ 259	$ 248	$ 354
Early retirement and severance costs	(5)	(20)	(67)
Adjusted general and administrative expenses	$ 254	$ 228	$ 287

Year Ended December 31, 2017 vs. 2016

Oil and gas net sales increased 19%, or $315 million, in 2017 compared to 2016, due to increases of approximately $392 million, $78 million and $29 million from higher oil, NGL and natural gas realized prices, respectively, partially offset by the effects of lower oil and natural gas production of $168 million and $16 million, respectively. The higher realized oil prices reflected the significant increase in global oil prices and improved differentials. Our total daily production volumes averaged 129 MBoe in 2017, compared with 140 MBoe in 2016, representing a year-over-year decline rate of 8%. Average oil production decreased by 9%, or 8,000 barrels per day, from 91,000 barrels per day in 2016 to 83,000 barrels per day in 2017. NGL production was 16,000 barrels per day in both 2017 and 2016. Natural gas production decreased by 8% to 182 MMcf per day.

Net derivative losses were $90 million in 2017 compared to $206 million in 2016, representing an overall change of $116 million. In 2017, we recorded $200 million less in non-cash derivative losses, partially offset by a cash payment of $7 million in 2017 compared with cash proceeds of $77 million in 2016. The non-cash change reflected changes in the commodity price curves based on our derivative positions at the end of each of the respective periods.

Other revenue increased 21%, or $28 million, in 2017 compared to 2016, due to increased margins from natural gas trading activities and increased third-party power sales from the Elk Hills power plant, which was offline for about half of the first quarter of 2016 for a planned turnaround.

Production costs increased $76 million to $876 million or $18.64 per Boe in 2017, compared to $800 million or $15.61 per Boe in 2016, resulting in 10% increase on an absolute dollar basis. The year-over-year increase was driven by increased activity in line with the stronger commodity prices and higher gas and electricity costs. Total production costs in 2016 reflected management's decision to selectively defer workovers and downhole maintenance activity in light of low commodity prices. The 2017 costs reflected higher downhole maintenance activity in line with the current price environment.

Our general and administrative expenses increased $11 million to $259 million in 2017 compared to 2016. Our adjusted general and administrative expenses, which excluded early retirement and severance costs, were $254 million and $228 million in 2017 and 2016, respectively. The 2017 period primarily reflected higher compensation expense related to bonus and the timing of equity-based compensation grants between years. The non-cash portion of general and administrative expenses, comprising equity compensation and pension settlement costs, was approximately $19 million and $25 million in 2017 and 2016, respectively.

DD&A expense decreased by $15 million in 2017 compared to 2016. Of this decrease, approximately $45 million was attributable to lower volumes, partially offset by an increase in the DD&A rate of approximately $30 million.

Taxes other than on income decreased 6% in 2017 compared to 2016, largely due to lower property taxes and greenhouse gas emissions costs.

The increase in other expenses, net of $27 million to $106 million in 2017, compared to $79 million in 2016, was largely the result of the absence of energy and property tax refunds received in 2016 as well as charges related to fires in the Ventura basin, increased fuel gas costs at our Elk Hills power plant and higher accretion expense.

Interest and debt expense, net, increased to $343 million in 2017, compared to $328 million in 2016, primarily due to higher blended interest rates, increased average borrowings as a result of our debt transactions and increased amortization of our deferred financing costs.

Net gains on early extinguishment of debt consisted of the gains on open-market repurchases in 2017 of $12 million, partially offset by a net loss related to early repayment of our 2014 Term Loan of $8 million. Net gains on early extinguishment of debt in 2016 consisted of open-market purchases, a debt-for-equity exchange and a cash tender for our Senior Notes.

Gains on asset divestitures reflected non-core asset sales during each of the respective periods.

Other non-operating expense in 2017 primarily reflected transaction costs related to our JVs.

In 2017, we did not provide any current or deferred tax benefit on pre-tax loss of $262 million as a result of our continued financial losses. For the same period of 2016, we had a deferred tax benefit of $78 million resulting from an adjustment to our 2015 valuation allowance. For 2016, we did not provide a tax provision on our pre-tax income of $279 million because the exclusion of gains related to our debt-reduction actions resulted in a tax loss, which we determined was not more-likely-than-not to be realized in the future.

Year Ended December 31, 2016 vs. 2015

Oil and gas net sales decreased 24%, or $513 million, in 2016 compared to 2015, due to reductions of approximately $282 million and $181 million from lower oil prices and volumes, respectively; $28 million and $26 million from lower natural gas prices and volumes, respectively; $14 million from lower NGL volumes; and an increase of $18 million from higher NGL prices. The lower realized oil prices reflected a 16% decrease in global oil prices. Daily oil and gas production volumes averaged 140,000 Boe in 2016, compared with 160,000 Boe in 2015, representing a 12.5% year-over-year decline rate, consistent with our estimated overall annual base decline rate. The 2016 production was negatively impacted by 1,000 Boe per day due to the PSCs in our Long Beach operations. Excluding this PSC effect, our year-over-year production decline would have been under 12%. Average oil production decreased by 13%, or 13,000 barrels per day, to 91,000 barrels per day in 2016 compared to 2015. NGL production decreased by 11% to 16,000 barrels per day. Natural gas production decreased by 14% to 197,000 MMcf per day, consistent with our focus on oil-based projects. The overall production decline continued to reflect our decision to withhold development capital and selectively defer workover and downhole maintenance activity in the early part of the year.

Derivative losses were $206 million in 2016, compared to gains of $133 million in 2015. Of the change, $335 million was due to the valuation of outstanding derivative contracts at the end of 2016 and $4 million was the result of lower gains from cash settlements. Overall, the 2016 derivative losses were primarily a function of the higher commodity price curve at the end of 2016 compared to the curve when the derivatives were implemented.

Production costs were $800 million or $15.61 per Boe in 2016, compared to $951 million or $16.30 per Boe in 2015, resulting in a 16% reduction on an absolute dollar basis. Of the absolute dollar reduction, approximately 25% related to lower energy costs, largely resulting from lower natural gas prices. The balance, or 75% of the reduction, came from ongoing cost-reduction initiatives which reduced costs across our operations in all categories including surface operations, downhole maintenance and labor costs.

Our general and administrative expenses were lower in 2016 compared to 2015 on a total dollar and per Boe basis, reflecting continued employee and contractor cost-reduction initiatives. Severance and early retirement costs of $20 million and $67 million were included in general and administrative expenses in 2016 and 2015, respectively. The non-cash portion of general and administrative expenses, comprising equity compensation and a portion of pension costs, was approximately $25 million and $30 million in 2016 and 2015, respectively.

DD&A expense decreased 44%, or $445 million, in 2016 compared to 2015, primarily due to a $376 million decrease in the DD&A rate that resulted from asset impairments in the fourth quarter of 2015, and an approximately $73 million decrease attributable to lower volumes.

At year-end 2015, we performed impairment tests with respect to our proved and unproved properties triggered by the sharp drop in oil prices in the fourth quarter of 2015, resulting in pre-tax asset impairment charges of $4.9 billion.

Taxes other than on income, which include ad valorem taxes, greenhouse gas emissions costs and production taxes, decreased 20%, or $36 million, in 2016 compared to 2015, reflecting lower property taxes assessed in the lower price environment.

Exploration expense decreased 36%, or $13 million, in 2016 compared to 2015, due to reduced lease rentals that we negotiated during the year and lower exploration activity.

The decrease in other expenses from $168 million in 2015 to $79 million in 2016 was largely the result of net gains in 2016 principally from energy and property tax refunds as well as certain 2015 asset write-downs.

Interest and debt expense, net, of $328 million in 2016, compared to $326 million in 2015, reflected higher interest rates on our new debt, increased amortization of deferred financing costs including a $12 million write-off of the deferred financing costs associated with the tender for our notes during 2016. Offsetting these effects were $71 million of amortization of the deferred gains from our December 2015 debt exchange and lower overall debt principal amounts.

Net gains on early extinguishment of debt of $805 million in 2016 consisted of open-market purchases, a debt-for-equity exchange and a cash tender for our Senior Notes. Net gains on early extinguishment of debt of $20 million in 2015 resulted from note repurchases, net of related expenses.

Gains on asset divestitures reflected non-core asset sales during 2016.

Other non-operating expense consisted of debt-related transaction costs in 2015.

In 2016, we had pre-tax income of $201 million and an income tax benefit of $78 million reflecting the release of a portion of the beginning of the year valuation allowance. Further, in 2016, we excluded CODI from taxable income which resulted in a tax loss. We did not recognize a resulting tax benefit due to the uncertainty of realizing such benefit. For 2015, we had a pre-tax loss of $5.5 billion and a $1.9 billion benefit which was net of a $294 million change related to a valuation allowance.

Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are cash flow from operations and available borrowing capacity under our 2014 Revolving Credit Facility. We also rely on other sources such as JV funding to supplement our capital program. During 2017, we closed two key JV transactions. Under these arrangements our JV partners invested $154 million in our drilling programs, some of which is not included in our consolidated results. In February 2018, we entered into the Ares JV in which we received $747 million in net proceeds and raised $50 million in a private placement of our common stock with an Ares-led investor group.

We expect the combination of these sources of capital will be adequate to fund future capital expenditures, debt service and operating needs. Through 2017, we maintained limited cash on hand due to our leverage position. Following the Ares JV and the private placement in February 2018, we paid off the then outstanding balance on our 2014 Revolving Credit Facility of $297 million and expect to carry a greater amount of cash on hand until the proceeds from these transactions are invested.

Significant changes in oil and natural gas prices have a material impact on our liquidity. Declining commodity prices negatively affect our operating cash flow but have a positive indirect effect on operating expenses. The inverse is also true during periods of rising commodity prices. To mitigate some of the risk inherent in oil prices, we have utilized various derivative instruments to hedge price risk. If commodity prices were to prevail through 2018 at about current levels, we would expect to be able to fund our operations and capital program with our operating cash flows and would not anticipate a net draw down on our 2014 Revolving Credit Facility. We maintain flexibility within our capital program that helps us to scale our internally funded capital as necessary to stay within our operating cash flow.

The Tax Act, signed into law on December 22, 2017, includes significant changes to corporate tax provisions including a reduction in the corporate tax rate, limitations on certain corporate deductions and favorable capital recovery provisions. This change in tax law is not expected to have any impact on our liquidity in the foreseeable future.

Currently, we have approximately $850 million of available borrowing capacity under our 2014 Revolving Credit Facility, before taking into account the monthly minimum $150 million liquidity requirement. Our ability to borrow funds under our 2014 Revolving Credit Facility is limited by the terms and conditions of that facility and our ability to comply with its covenants.

As of December 31, 2017, our debt consisted of the following credit agreements, second lien notes and senior notes:

	Outstanding Principal (in millions)	Interest Rate	Maturity	Security[(a)]
Credit Agreements				
2014 Revolving Credit Facility[(a)]	$ 363	LIBOR plus 3.25%-4.00% ABR plus 2.25%-3.00%	June 30, 2021	Shared First-Priority Lien
2017 Credit Agreement	1,300	LIBOR plus 4.75% ABR plus 3.75%	December 31, 2022[(b)]	Shared First-Priority Lien
2016 Credit Agreement	1,000	LIBOR plus 10.375% ABR plus 9.375%	December 31, 2021	First-Priority Lien
Second Lien Notes				
Second Lien Notes	2,250	8%	December 15, 2022	Second-Priority Lien
Senior Notes				
5% Senior Notes due 2020	100	5%	January 15, 2020	Unsecured
5 ½% Senior Notes due 2021	100	5.5%	September 15, 2021	Unsecured
6% Senior Notes due 2024	193	6%	November 15, 2024	Unsecured
Long-Term Debt—Principal Amount	$ 5,306			

(a) Following the Ares JV transaction in February 2018, (i) we have no outstanding principal balance on our 2014 Revolving Credit Facility and (ii) the Elk Hills power plant and certain other midstream assets are no longer subject to liens securing our indebtedness.

(b) The 2017 Credit Agreement is subject to a springing maturity of 91 days prior to the maturity of our 2016 Credit Agreement if more than $100 million is outstanding at that time.

Credit Agreements

2014 Revolving Credit Facility

In September 2014, we entered into a Credit Agreement with JPMorgan Chase Bank, N.A, as administrative agent, and certain other lenders. This credit agreement currently consists of a $1 billion senior revolving loan facility (2014 Revolving Credit Facility), which we are permitted to increase by up to $50 million if we obtain additional commitments from new or existing lenders. Previously this credit agreement included a term loan facility (2014 Term Loan) that was repaid in full in November 2017.

As of December 31, 2017, we had approximately $489 million of available borrowing capacity, before taking into account a $150 million month-end minimum liquidity requirement. Our 2014 Revolving Credit Facility also includes a sub-limit of $400 million for the issuance of letters of credit. As of December 31, 2017 and 2016, we had letters of credit of approximately $148 million and $130 million, respectively. These letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters.

Security – The lenders share a first-priority lien on a substantial majority of our assets with the lenders under of 2017 Credit Agreement. Following the formation of the Ares JV in February 2018, the Elk Hills power plant and certain other midstream assets are no longer subject to the shared first-priority lien.

Interest Rate – We can elect to borrow at either a London Interbank Offered Rate (LIBOR) rate or an alternate base rate (ABR), in each case plus an applicable margin. The ABR is equal to the highest of (i) the federal funds effective rate plus 0.50%, (ii) the administrative agent's prime rate and (iii) the one-month LIBOR rate plus 1.00%. The applicable margin is adjusted based on the borrowing base utilization percentage under the 2014 Revolving Credit Facility and will vary from (i) in the case of

LIBOR loans, 3.25% to 4.00% and (ii) in the case of ABR loans, 2.25% to 3.00%. The unused portion of our commitments is subject to a commitment fee that ranges from 0.30% to 0.50% per annum. We also pay customary fees and expenses. Interest on ABR loans is payable quarterly in arrears. Interest on LIBOR loans is payable at the end of each LIBOR period, but not less than quarterly.

Maturity Date – Our 2014 Revolving Credit Facility matures on June 30, 2021. Previously this facility was subject to a springing maturity of 273 days prior to the maturity of each of our 2020 Notes or our 2021 Notes if more than $100 million of such notes were outstanding on such date. During the fourth quarter of 2017, we repurchased $65 million in principal amount of 2020 Notes and $35 million in principal amount of 2021 Notes which eliminated this springing maturity feature.

Amortization Payments – The 2014 Revolving Credit Facility does not include any obligation to make amortization payments. In November 2017, we paid the remaining balance of our 2014 Term Loan in the amount of $559 million. Prior to that, we made a $16 million prepayment on our 2014 Term Loan from the proceeds of non-core asset sales in February 2017. In 2016 and through the nine months ended September 30, 2017, we made scheduled quarterly payments of $25 million on our 2014 Term Loan for an aggregate amount of $175 million. In August 2016, we made a $250 million prepayment on our 2014 Term Loan from the proceeds of our 2016 Credit Agreement.

Borrowing Base – The borrowing base is redetermined each May 1 and November 1, and was mostly recently reaffirmed at $2.3 billion on November 1, 2017. The borrowing base is based upon a number of factors, including commodity prices and reserves, declines in which could cause our borrowing base to be reduced. Increases in our borrowing base require approval of at least 80% of our lenders while decreases or affirmations require a two-thirds approval, in each case as measured by relative commitment amount. We and the lenders (requiring a request from the lenders holding two-thirds of the commitments) each may request a special redetermination once in any period between three consecutive scheduled redeterminations. We will be permitted to have collateral released when both (i) our credit ratings are at least Baa3 from Moody's and BBB- from S&P, in each case with a stable or better outlook, and (ii) certain permitted liens securing other debt are released.

Financial Covenants – As of December 31, 2017, our financial performance covenants included a monthly minimum liquidity requirement of not less than $150 million and the following:

Ratio	Components[(a)]	Required Levels	Tested
Maximum leverage ratio	Ratio of indebtedness under our 2014 Revolving Credit Facility to trailing four-quarter Adjusted EBITDAX	Not greater than 1.90 to 1.00 through 2019 Not greater than 1.50 to 1.00 after 2019	Quarterly
Minimum interest coverage ratio	Ratio of Adjusted EBITDAX to consolidated cash interest charges	Not less than 1.20 to 1.00	Quarterly
Minimum asset coverage ratio	Ratio of PV-10 to first lien indebtedness	Not less than 1.20 to 1.00	Quarterly

(a) Refer to the terms of our credit agreements for more detailed descriptions of the components of our financial covenants.

Other Covenants – Our 2014 Revolving Credit Facility include covenants that, among other things, restrict our ability to incur additional indebtedness, grant liens, make asset sales and investments, repay existing indebtedness, pay dividends to common stockholders, make subsidiary distributions and enter into transactions that would result in fundamental changes. Generally, these covenants include exceptions that allow us to pursue some of these activities in certain circumstances. In addition to these covenants, we must also apply cash on hand in excess of $150 million daily to repay amounts outstanding.

Except for dispositions to development JVs, we must generally apply all of the proceeds from the sale of assets included in our borrowing base to repay loans outstanding under our 2014 Revolving Credit Facility. With respect to the sale of non-borrowing base assets (other than the Elk Hills power plant), we must apply the net cash proceeds to repay outstanding loans as follows:

- 25% of such proceeds for all net cash proceeds received up to $500 million
- 50% of such proceeds for all net cash proceeds received between $500 million and $1 billion
- 75% of such proceeds for all net cash proceeds received in excess of $1 billion.

We are permitted to use the balance of the proceeds for general corporate purposes, including acquisitions, and to repurchase our Second Lien Notes and Senior Notes subject to certain conditions, including that any repurchase be at a 20% minimum discount to par, pro-forma compliance with our financial performance covenants and that we maintain minimum liquidity of $250 million following such repurchase.

In connection with the Ares JV transaction, we used $297 million of the net proceeds to repay all of the then outstanding loans under our 2014 Revolving Credit Facility.

Prior Amendments – Our 2014 Revolving Credit Facility was most recently amended in November 2017. As part of that amendment, we repaid the $559 million balance of our 2014 Term Loan and modified the financial and other covenants of our 2014 Revolving Credit Facility.

2017 Credit Agreement

In November 2017, we entered into a 1.3 billion credit agreement with The Bank of New York Mellon Trust Company, N.A., as administrative agent, and certain other lenders (2017 Credit Agreement). The net proceeds were used to pay the $559 million remaining balance of our 2014 Term Loan, resulting in a loss on the early extinguishment of debt of $8 million, reduce the balance of our 2014 Revolving Credit Facility and pay accrued interest. The proceeds received were net of a $26 million original issue discount and $38 million in transaction costs. As of December 31, 2017, we had a $1.3 billion term loan outstanding under our 2017 Credit Agreement.

Security – Our 2017 Credit Agreement is secured by the same shared first-priority lien used to secure our 2014 Revolving Credit Facility.

Maturity Date – The loans mature on December 31, 2022, subject to a springing maturity of 91 days prior to the maturity of our 2016 Credit Agreement if more than $100 million is outstanding at that time. Previously these loans included a springing maturity of 91 days prior to the maturity of our 2020 Notes or our 2021 Notes if more than $100 million of such notes were outstanding on such date. During the fourth quarter of 2017, we repurchased $65 million in principal amount of 2020 Notes and $35 million in principal amount of 2021 Notes which eliminated the springing maturity feature in the 2017 Credit Agreement that was tied to those notes. Prepayment more than 90 days prior to maturity is subject to a 2% premium.

Financial and Other Covenants – We are required to maintain a first-lien asset coverage ratio of not less than 1.20 to 1.00 as of any June 30 and December 31. In addition, our 2017 Credit Agreement provides for customary covenants and events of default consistent with, or generally less restrictive than, the covenants in our 2014 Revolving Credit Facility, including limitations on additional indebtedness, liens, asset dispositions, investments and restricted payments and other negative covenants, in each case subject to certain limitations and exceptions.

2016 Credit Agreement

In August 2016, we entered into a $1 billion credit agreement with The Bank of New York Mellon Trust Company, N.A., as administrative agent, and certain other lenders (2016 Credit Agreement). The net proceeds from the 2016 Credit Agreement were used to (i) prepay $250 million of our 2014 Term Loan and (ii) reduce our 2014 Revolving Credit Facility by $740 million. The proceeds received were net of a $10 million original issue discount. As of December 31, 2017, we had a $1 billion term loan outstanding under our 2016 Credit Agreement.

Security – Our 2016 Credit Agreement is secured by a first-priority lien on a substantial majority of our assets but is second in collateral recovery to our 2014 Revolving Credit Facility and 2017 Credit Agreement.

Maturity Date – The loans mature on December 31, 2021. Previously these loans included a springing maturity of 91 days prior to the maturity of our 2020 Notes or our 2021 Notes if more than $100 million of such notes were outstanding on such date. During the fourth quarter of 2017, we repurchased $65 million in principal amount of 2020 Notes and $35 million in principal amount of 2021 Notes which eliminated the springing maturity feature in the 2016 Credit Agreement that was tied to those notes. Prepayment is subject to a variable make-whole amount prior to the fourth anniversary. Following the fourth anniversary, we may redeem at par.

Financial and Other Covenants – We are required to maintain a first–lien asset coverage ratio of not less than 1.20 to 1.00 as of any June 30 and December 31. Our 2016 Credit Agreement also includes other covenants that are substantially similar to our 2017 Credit Agreement.

Second Lien Notes

In December 2015, we issued $2.25 billion in aggregate principal amount of 8% senior secured second-lien notes due December 15, 2022 (Second Lien Notes). The Second Lien Notes were issued in exchange for $2.8 billion of our then outstanding Senior Notes. We recorded a deferred gain of approximately $560 million on the debt exchange, which is being amortized using the effective interest rate method over the term of our Second Lien Notes. We pay cash interest semiannually in arrears on June 15 and December 15.

Security – Our Second Lien Notes are secured on a junior-priority basis to the first-priority liens that secure the loans under our 2014 Revolving Credit Facility, 2017 Credit Agreement and 2016 Credit Agreement.

Financial and Other Covenants – The indenture includes covenants that, among other things, limit our ability to grant liens securing borrowed money (subject to certain exceptions) and restrict our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. The covenants are not, however, directly linked to measures of our financial performance. In addition, if we experience a “change of control triggering event” (as defined in the indenture), we will be required, unless we have exercised our right to redeem our Second Lien Notes, to offer to purchase our Second Lien Notes at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest. The indenture also restricts our ability to sell certain assets and to release collateral from liens securing our Second Lien Notes, unless the collateral is also released in compliance with our senior credit facilities.

Redemption – We may redeem our Second Lien Notes (i) prior to December 15, 2018, in whole or in part at a redemption price equal to 100% of the principal amount redeemed plus a make-whole amount and accrued and unpaid interest, (ii) between December 15, 2018 and 2020, in whole or in part at a fixed redemption price ranging from 104% to 102% of the principal amount redeemed plus accrued and unpaid interest and (iii) thereafter in whole or in part at a redemption price equal to 100% of the principal amount redeemed plus accrued and unpaid interest.

Senior Notes

In October 2014, we issued $5 billion in aggregate principal amount of our senior unsecured notes, including $1 billion of 5% notes due January 15, 2020 (2020 Notes), $1.75 billion of 5 ½% notes due September 15, 2021 (2021 Notes) and $2.25 billion of 6% notes due November 15, 2024 (2024 Notes and, collectively, Senior Notes). We used the net proceeds from the issuance of our Senior Notes to make a $4.95 billion cash distribution to Occidental in connection with the Spin-off in October 2014.

Repurchases and Exchanges – In 2015, we repurchased approximately $33 million in principal amount of our 2020 Notes for $13 million in cash. We also exchanged a substantial majority of our Senior Notes for our Second Lien Notes in December 2015 as described above. In 2016, we repurchased over $1.5 billion in principal amount of our outstanding Senior Notes, primarily using drawings of $750 million on our 2014 Revolving Credit Facility and cash from operations. We also exchanged approximately 3.4 million shares of our common stock for $100 million in aggregate principal amount of our Senior Notes. In the first quarter of 2017, we purchased $28 million in aggregate principal amount of our 2020 Notes for $24 million in cash, resulting in a $4 million pre-tax gain. As described above, in the fourth quarter of 2017, we also repurchased $65 million and $35 million in aggregate principal amount of our 2020 Notes and our 2021 Notes, respectively, for $92 million in cash, resulting in an $8 million pre-tax gain.

Financial and Other Covenants – The indenture includes covenants that, among other things, limits our ability to grant liens securing borrowed money subject to certain exceptions and restricts our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. The covenants are not, however, directly linked to measures of our financial performance. In addition, if we experience a “change of control triggering event” (as defined in the indenture), we will be required, unless we have exercised our right to redeem our Senior Notes, to offer to purchase our Senior Notes at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest.

Redemption – We may redeem our Senior Notes prior to their maturity dates, in whole or in part, at a redemption price equal to 100% of the principal amount redeemed plus accrued and unpaid interest and, generally, a make-whole amount.

Other

At December 31, 2017, we were in compliance with all financial and other debt covenants.

All obligations under our 2014 Revolving Credit Facility, 2017 Credit Agreement and 2016 Credit Agreement (collectively, Credit Facilities) as well as our Second Lien Notes are guaranteed both fully and unconditionally and jointly and severally by all of our material wholly owned subsidiaries.

The terms and conditions of all of our indebtedness are subject to additional qualifications and limitations that are set forth in the relevant governing documents.

A one-eighth percent change in the variable interest rates on the borrowings under our Credit Facilities on December 31, 2017 would result in a $3 million change in annual interest expense.

Derivatives and Hedging

Our most significant market exposure is the volatility of commodity prices. Realized prices are primarily driven by prevailing worldwide prices for crude oil and fluctuations in spot market prices, which are outside of our control, and can result in unpredictable operating cash flows. Global oil markets are influenced by many factors, including the over-supply of oil in the last few years. We maintain a commodity hedging program to help protect our cash flows, margins and capital program from the volatility of commodity prices and to improve our ability to comply with our debt covenants.

We currently have the following Brent-based crude oil contracts, which includes activity subsequent to December 31, 2017:

	Q1 2018	Q2 2018	Q3 2018	Q4 2018	Q1 2019	Q2 -Q4 2019	FY 2020
Sold Calls:							
Barrels per day	9,000	6,200	16,100	16,100	1,100	1,000	500
Weighted-average 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 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 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 price per barrel	$ 45.00	$ 45.00	$ 46.04	$ 45.00	$ 47.50	$ —	$ —
Swaps:							
Barrels per day	38,300	34,000 (1)	19,000 (2)	19,000 (2)	7,000 (3)	—	—
Weighted-average price per barrel	$ 60.03	$ 60.00	$ 60.13	$ 60.13	$ 67.71	$ —	$ —

(1) Certain of our counterparties have options to increase swap volumes by up to 19,000 barrels per day at a weighted-average price of $60.00 for the second quarter of 2018.

(2) Certain of our counterparties have options to increase swap volumes by up to 29,000 barrels per day at a weighted-average price of $60.50 for the second half of 2018.

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

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

The outcomes of the derivative positions are as follows:

- Sold calls – we make settlement payments for prices above the indicated weighted-average price per barrel.
- Purchased calls – we receive settlement payments for prices above the indicated weighted-average price per barrel.
- Purchased puts – we receive settlement payments for prices below the indicated weighted-average price per barrel.
- Sold puts – we make settlement payments for prices below the indicated weighted-average price per barrel.

From time to time, we may use combinations of these positions to increase the efficacy of our hedging program.

Cash Flow Analysis

	2017	2016	2015
		(in millions)	
Net cash provided by operating activities	$ 248	$ 130	$ 403
Net cash used in investing activities	$ (313)	$ (61)	$ (757)
Net cash provided (used) by financing activities	$ 73	$ (69)	$ 352
Adjusted EBITDAX	$ 761	$ 616	$ 906

Year Ended December 31, 2017 vs. 2016

Our net cash provided by operating activities is sensitive to many variables including market changes in commodity prices. Commodity price sensitivity triggers changes in other variables in our business including our level of workover activity and adjustments to our capital program. Operating cash flow increased 91% or $118 million to $248 million in 2017 from $130 million in 2016 due to higher realized prices on lower volumes, partially offset by lower receipts from settlements related to our derivative contracts. Production costs increased in 2017 by $76 million as we ramped up activity primarily related to downhole maintenance and as fuel gas and electricity prices increased. Our hedging program reduced our sensitivity to price changes.

Cash interest increased $12 million in 2017 due to higher blended interest rates and increased average borrowings on our overall debt. Taxes other than on income decreased $8 million from 2016 due to lower property taxes and greenhouse gas taxes, partially offset by an increase in the production tax rate. Other changes in operating cash flow relate to higher general and administrative expenses and changes in working capital.

Our net cash used in investing activities of $313 million in 2017 included approximately $344 million of capital investments (net of $27 million in capital-related accruals), of which $96 million was funded by BSP and reported as cash provided by financing activities. Our share of the total capital investment of $248 million was funded with cash from operations. The capital investment was partially offset by proceeds from asset divestitures of $33 million. Our net cash used in investing activities of $61 million in 2016 primarily included $81 million of capital investments (net of changes in capital-related accruals), partially offset by $20 million from asset divestitures.

Our net cash provided by financing activities of $73 million in 2017 was primarily comprised of $1.3 billion of proceeds from our 2017 Credit Agreement and $98 million in net contributions from our BSP JV, partially offset by $650 million in repayments on our 2014 Term Loan, $484 million of net payments on our 2014 Revolving Credit Facility, $158 million of debt repurchases and transaction costs and $8 million of distributions paid to BSP. In 2016, our net cash used by financing activities of $69 million included approximately $821 million in debt repurchases and transaction costs and $350 million of payments on our 2014 Term Loan, partially offset by the $990 million in proceeds from the issuance of our 2016 Credit Agreement and $108 million of net proceeds from our 2014 Revolving Credit Facility.

Year Ended December 31, 2016 vs. 2015

Our net cash provided by operating activities in 2016 decreased by $273 million from $403 million in 2015 to $130 million in 2016. The decrease reflected lower revenues of approximately $521 million, primarily due to lower commodity prices and volumes, net of cash generated from our hedging program, $25 million of higher interest payments and the negative effect of working capital changes of $16 million, partially offset by lower costs including lower production costs of $151 million, cash general and administrative expenses of $47 million, taxes other than on income of $36 million and exploration expense of $13 million.

Our net cash used in investing activities decreased by approximately $696 million from $757 million in 2015 to $61 million in 2016. The decrease reflected significantly reduced capital investments, lower payments related to capital activity from prior periods and no acquisitions in 2016.

Our net cash used in financing activities of $69 million in 2016 included approximately $350 million of payments on our 2014 Term Loan and debt repurchases and transaction costs of $821 million, partially offset by the issuance of our 2016 Credit Agreement for $990 million and $108 million of net proceeds from our 2014 Revolving Credit Facility. Our net cash provided by financing activities of $352 million in 2015 primarily included approximately $379 million of net proceeds on our 2014 Revolving Credit Facility, partially offset by 2015 debt repurchase and amendment costs of $23 million and $12 million in cash dividends paid.

Non-GAAP Financial Measures

The following table sets forth a reconciliation of the GAAP measure of net cash provided by operating activities to the non-GAAP financial measure of Adjusted EBITDAX. For a discussion of our non-GAAP financial measure of Adjusted EBITDAX, see *Statements of Operations* above.

	2017	2016	2015
		(in millions)	
Net cash provided by operating activities	$ 248	$ 130	$ 403
Cash interest	396	384	359
Exploration expenditures	20	20	27
Other changes in operating assets and liabilities	76	95	106
Other, net	21	(13)	11
Adjusted EBITDAX	$ 761	$ 616	$ 906

The increase in Adjusted EBITDAX in 2017 compared to 2016 primarily resulted from higher revenues partially offset by higher production costs, reflecting increased activity and higher gas and electricity costs. The decrease in Adjusted EBITDAX in 2016 compared to 2015 primarily resulted from lower revenues partially offset by lower production costs and general and administrative expenses.

2017 and 2018 Capital Program

We create value by investing our operating cash flows back into our business. We are focusing our 2018 capital plan on oil projects, which provide high margins and low decline rates that we believe will generate positive cash flow to fund increasing capital budgets that will grow production. Our low decline rates compared to our industry peers plus our high level of operational control give us the flexibility to adjust the level of such capital investments as circumstances warrant.

In 2017, we invested approximately $371 million of capital, excluding $58 million funded by our JV partner MIRA, as compared to the total capital deployed of approximately $75 million in 2016. Our capital predominantly targeted projects in the San Joaquin and Los Angeles basins. Virtually all of our 2017 capital was directed towards oil-weighted production consistent with 2016 and 2015. Of the total 2017 capital program, approximately $177 million was allocated to drilling wells, $89 million to capital workovers, $71 million to facilities and compression expansion, $25 million to maintenance and occupational health, safety and environmental projects and $9 million to exploration and other items.

The table below sets forth our capital investments by basin and recovery mechanism for the year ended December 31, 2017 (in millions):

	Conventional				Unconventional		
	Primary	Waterflood	Steamflood	Total	Primary	Other	Total Capital Investments
Basin:							
San Joaquin	$ 27	$ 40	$ 38	$ 105	$ 172	$ —	$ 277
Los Angeles	—	54	—	54	—	—	54
Ventura	23	2	—	25	—	—	25
Sacramento	6	—	—	6	—	—	6
Basin Total	56	96	38	190	172	—	362
Exploration and other	—	—	—	—	—	9	9
Total[(a)]	$ 56	$ 96	$ 38	$ 190	$ 172	$ 9	$ 371

(a) Of the net $98 million contributed by BSP, $96 million was used for capital investment.

With stronger expected cash flows, we estimate our 2018 capital program will range from $425 million to $450 million, which includes approximately $100 to $150 million in JV capital. Our 2018 capital program may grow further through additional tranches from existing JVs as well as potential new JVs.

We are focusing our 2018 capital on oil projects, which provide higher margins and low decline rates that we believe will generate cash flow to fund increasing capital budgets that will grow production. Our approach to our 2018 drilling program is consistent with our stated strategy to remain financially disciplined and fund projects through either internally generated cash flow or JV capital to maintain our liquidity and further strengthen our balance sheet. We continue to deploy our partners' capital as part of our BSP and MIRA joint ventures and opportunistically pursue additional strategic relationships. We will deploy capital to projects that help continue to stabilize our production, develop our long-term resources and return our production to a growth profile. Our current drilling inventory comprises a diversified portfolio of oil and natural gas locations that are economically viable in a variety of operating and commodity price conditions.

We will continue to focus on our core fields: Elk Hills, Wilmington, Kern Front and the delineation and appraisal of Kettleman North Dome and Buena Vista. We will also restart our development activities in the Huntington Beach field.

Our 2018 drilling program includes development of conventional and unconventional resources. The depth of our primary conventional wells is expected to range from 2,000 to 15,000 feet. With a significant reduction in our drilling costs since 2014, many of our deep conventional and unconventional wells have become more competitive, and we expect to use approximately 60% of our capital on drilling. We expect to focus our conventional program of approximately 130 wells primarily in Wilmington, Huntington Beach, Kern Front, Pleito Ranch and Mount Poso, which will largely consist of waterfloods and steamfloods along with some primary drilling. We intend to drill approximately 20 unconventional wells in the Buena Vista and Kettleman areas.

We also plan to use over 20% of our 2018 capital program for capital workovers on existing well bores. Capital workovers are some of the highest VCI projects in our portfolio and generally include well deepenings, recompletions, changes of lift methods and other activities designed to add incremental productive intervals and reserves.

Further, over 15% of our 2018 capital program is intended for development facilities for our newer projects, including pipeline and gathering line interconnections, gas compression and water management systems, and about 5% is intended to be used for exploration and to maintain the mechanical integrity, safety and environmental performance of our operations.

As a result of higher activity levels, our production flattened in the second half of 2017 and continues to improve in 2018 on a gross basis. We believe that the actions we have taken since the Spin-off to streamline our business and reduce costs, together with recent price increases, have enabled us to increase our activity level and grow our production. In addition, we will continue to build our inventory of available projects, which will position us to take advantage of future higher prices.

Off-Balance-Sheet Arrangements

As of December 31, 2017, we had letters of credit of $148 million under our 2014 Revolving Credit Facility and no other material off-balance-sheet arrangements other than those noted below.

Leases

We, or certain of our subsidiaries, have entered into various operating lease agreements, mainly for field equipment, office space and office equipment. We lease assets when leasing offers greater operating flexibility. Lease payments are generally expensed as part of production costs or general and administrative expenses. For more information, see *Contractual Obligations* below.

Contractual Obligations

The table below summarizes and cross-references our contractual obligations as of December 31, 2017. This summary indicates on- and off-balance-sheet obligations as of December 31, 2017.

	Payments Due by Year				
	Total	**2018**	**2019 and 2020**	**2021 and 2022**	**2023 and thereafter**
			(in millions)		
On-Balance Sheet					
Long-term debt—principal amount[(a)]	$ 5,306	$ —	$ 100	$ 5,013	$ 193
Interest on long-term debt[(b)]	1,960	423	842	673	22
Asset retirement obligations[(c)]	422	19	—	—	403
Pension and postretirement	113	3	7	7	96
Greenhouse gas emissions[(d)]	106	106			
Production and ad valorem taxes	24	24	—	—	—
Other liabilities	14	5	4	4	1
Off-Balance Sheet					
Operating leases	43	12	16	7	8
Purchase obligations[(e)(f)]	215	129	51	7	28
Total[(g)]	$ 8,203	$ 721	$ 1,020	$ 5,711	$ 751

(a) In performing the calculation, the 2014 Revolving Credit Facility borrowings outstanding at December 31, 2017 of $363 million were assumed to be outstanding for the entire term of the agreement. See *Item 8—Financial Statements and Supplementary Data—Note 5 Debt* for more information.

(b) The calculation of interest payable on the variable interest debt assumes the interest rate at December 31, 2017 to be the applicable interest rate for the entire term.

(c) Represents the estimated future asset retirement obligations on a discounted basis. We do not show the long-term asset retirement obligations by year as we are not able to precisely predict the timing of these amounts. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to revisions based on numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See *Item 8—Financial Statements and Supplementary Data—Note 1 The Spin-Off, Summary of Significant Accounting Policies and Other* for more information.

(d) The amount reflects (i) our expected cost in 2018 to acquire remaining allowances for the 2015-2017 compliance period, including replacement of GHG allowances that we previously monetized in 2016 and (ii) a minor amount to obtain and acquire allowances for the compliance period that commences in 2018.

(e) Amounts include payments that will become due under long-term agreements to purchase goods and services used in the normal course of business including pipeline capacity and rig termination costs.

(f) Included in these obligations is a commitment to invest approximately $84 million in evaluation and development activities for one of our oil and gas properties prior to the end of 2018. Any deficiency in meeting this capital investment obligation would need to be paid in cash. Our 2018 capital program includes the required development plans for this property, and we expect to fulfill the minimum investment requirement.

(g) Amount excludes (1) unrecognized tax benefit of $25 million due to uncertainty with respect to the timing of future cash outflows and (2) $19 million in obligations for derivatives based on market information as of December 31, 2017 due to the potential significant changes to the value based on changing market conditions.

Lawsuits, Claims, Commitments and Contingencies

We are involved, in the normal course of business, in lawsuits, environmental and other claims and other contingencies that seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2017 and 2016 were not material to our balance sheets as of such dates. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We have certain commitments under contracts, including purchase commitments for goods and services used in the normal course of business including pipeline capacity and rig termination costs. At December 31, 2017, total purchase obligations on a discounted basis were approximately $215 million, which included approximately $129 million, $33 million, $18 million, $4 million and $3 million that will be paid in 2018, 2019, 2020, 2021 and 2022, respectively. Included in these obligations is a commitment to invest approximately $84 million in evaluation and development activities for one of our oil and gas properties prior to the end of 2018. Any deficiency in meeting this capital investment obligation would need to be paid in cash. Our 2018 capital program includes development plans for these properties, and we expect to fulfill the minimum investment requirement.

We, our subsidiaries, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with the Spin-off, purchases and other transactions that they have entered into with us. These indemnities include indemnities made to Occidental Petroleum Corporation (Occidental), our former parent, against certain tax-related liabilities that may be incurred by Occidental relating to the Spin-off and liabilities related to operation of our business while it was still owned by Occidental. As of December 31, 2017, we are not aware of material indemnity claims pending or threatened against us.

We are currently under examination by the Internal Revenue Service for our U.S. federal income tax returns for the post-Spin-off period in 2014 and calendar year 2015. No significant issues have been raised to date. The U.S. federal income tax return for 2016 and the California franchise tax returns for 2014 through 2016 remain subject to examination.

Critical Accounting Policies and Estimates

See *Item 8—Financial Statements and Supplementary Data—Note 1 The Spin-Off, Summary of Significant Accounting Policies and Other* for our critical accounting policies and estimates that involve management's judgment and that could result in a material impact to the financial statements due to the levels of subjectivity and judgment.

Significant Accounting and Disclosure Changes

See *Item 8—Financial Statements and Supplementary Data—Note 2 Accounting and Disclosure Changes* for a discussion of new accounting matters.

ITEM 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

General

Our financial results are sensitive to fluctuations in oil, NGL and gas prices. In 2018, we expect that price changes at current levels of production, including the impact of existing hedges, will affect our pre-tax annual income and cash flows as follows:

		(in millions)
Pre-tax 2018 Price Sensitivities		
$1 change in Brent index - Oil[(a)]	$	3.3
$1 change in Brent index - NGLs	$	3.2
$0.50 change in NYMEX - Gas[(b)]	$	14.0

(a) Amounts reflect the sensitivity with respect to unhedged barrels at a Brent index price at $60.00 per barrel and include the effect of production sharing type contracts in our Wilmington field operations.

(b) Amounts reflect the sensitivity with respect to unhedged barrels at a NYMEX index price at $3.00 per barrel and includes the offsetting effect of Elk Hills power plant and steam consumption.

Due to our tax position, there is no difference between the impact on our income and cash flows. These price-change sensitivities include the impact on income of volume changes under arrangements similar to production-sharing contracts. If production and price levels change in the future, the sensitivity of our results to prices also will change.

Derivatives

As of December 31, 2017, we had a net derivative liability of $133 million carried at fair value, using industry-standard models with various inputs, including quoted forward prices. See additional hedging information in *Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources*.

Counterparty Credit Risk

Our credit risk relates primarily to trade receivables and derivative financial instruments. Credit exposure for each customer is monitored for outstanding balances and current activity. For derivative instruments entered into as part of our hedging program, we are subject to counterparty credit risk to the extent the counterparty is unable to meet its settlement commitments. We actively manage this credit risk by selecting counterparties that we believe to be financially strong and continue to monitor their financial health. Concentration of credit risk is regularly reviewed to ensure that counterparty credit risk is adequately diversified.

As of December 31, 2017, the substantial majority of the credit exposures related to our derivative financial instruments was with investment grade counterparties. We believe exposure to credit-related losses at December 31, 2017 was not material and losses associated with credit risk have been insignificant for all years presented.

Interest Rate Risk

As of December 31, 2017, we had borrowings of $1.3 billion outstanding under our 2017 Credit Agreement, $1 billion outstanding under our 2016 Credit Agreement and $363 million outstanding under our 2014 Revolving Credit Facility, all of which carry variable interest rates. A one-eighth percent change in the interest rates on these outstanding borrowings under these facilities would result in an approximately $3 million change in annual interest expense.

The following table shows our fixed- and variable-rate debt as of December 31, 2017 (in millions):

Year of Maturity	U.S. Dollar Fixed-Rate Debt	U.S. Dollar Variable-Rate Debt	Total
2018	$ —	$ —	$ —
2019	—	—	—
2020	100	—	100
2021	526	1,363	1,889
2022	1,824	1,300	3,124
Thereafter	193	—	193
Total	$ 2,643	$ 2,663	$ 5,306
Weighted-average interest rate	7.65%	8.31%	7.98%
Fair value	$ 2,185	$ 2,663	$ 4,848

FORWARD-LOOKING STATEMENTS

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

- financial position, liquidity, cash flows and results of operations
- business prospects
- transactions and projects
- operating costs
- Value Creation Index (VCI) metrics are based on certain estimates including future rates, costs and commodity prices
- operations and operational results including production, hedging and capital investment
- 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. We also believe third-party statements we cite are accurate but have not independently verified them and do not warrant their accuracy or completeness. Factors (but not necessarily all the factors) that could cause results to differ include:

- commodity price changes
- debt limitations on our financial flexibility
- insufficient cash flow to fund planned investment
- inability to enter desirable transactions including acquisitions, asset sales and joint ventures
- legislative or regulatory changes, including those related to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products
- 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 *Item 1A—Risk Factors*.

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

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
California Resources Corporation:

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of California Resources Corporation and subsidiaries (the Company) as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes (collectively, the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Basis for Opinion

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Assessment of and Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control Over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

We have served as the Company’s auditor since 2014.

Los Angeles, California
February 26, 2018

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets
As of December 31, 2017 and 2016
(in millions, except share data)

	2017	2016
CURRENT ASSETS		
Cash	$ 20	$ 12
Trade receivables	277	232
Inventories	56	58
Other current assets, net	130	123
Total current assets	483	425
PROPERTY, PLANT AND EQUIPMENT	21,260	20,915
Accumulated depreciation, depletion and amortization	(15,564)	(15,030)
Total property, plant, equipment, net	5,696	5,885
OTHER ASSETS	28	44
TOTAL ASSETS	$ 6,207	$ 6,354
CURRENT LIABILITIES		
Current maturities of long-term debt	$ —	$ 100
Accounts payable	257	219
Accrued liabilities	475	407
Total current liabilities	732	726
LONG-TERM DEBT—PRINCIPAL AMOUNT	5,306	5,168
DEFERRED GAIN AND ISSUANCE COSTS, NET	287	397
OTHER LONG-TERM LIABILITIES	602	620
EQUITY		
Preferred stock (20 million shares authorized at $0.01 par value) no shares outstanding at December 31, 2017 or 2016	—	—
Common stock (200 million shares authorized at $0.01 par value) outstanding shares (2017—42,901,946 shares and 2016—42,542,637 shares)	—	—
Additional paid-in capital	4,879	4,861
Accumulated deficit	(5,670)	(5,404)
Accumulated other comprehensive loss	(23)	(14)
Total equity attributable to common stock	(814)	(557)
Noncontrolling interest	94	—
Total equity	(720)	(557)
TOTAL LIABILITIES AND EQUITY	$ 6,207	$ 6,354

The accompanying notes are an integral part of these consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations
For the years ended December 31, 2017, 2016 and 2015
(in millions, except share data)

	2017	2016	2015
REVENUES AND OTHER			
Oil and gas net sales	$ 1,936	$ 1,621	$ 2,134
Net derivative (losses) gains	(90)	(206)	133
Other revenue	160	132	136
Total revenues and other	2,006	1,547	2,403
COSTS AND OTHER			
Production costs	876	800	951
General and administrative expenses	259	248	354
Depreciation, depletion and amortization	544	559	1,004
Asset impairments	—	—	4,852
Taxes other than on income	136	144	180
Exploration expense	22	23	36
Other expenses, net	106	79	168
Total costs and other	1,943	1,853	7,545
OPERATING INCOME (LOSS)	63	(306)	(5,142)
NON-OPERATING (LOSS) INCOME			
Interest and debt expense, net	(343)	(328)	(326)
Net gains on early extinguishment of debt	4	805	20
Gains on asset divestitures	21	30	—
Other non-operating expense	(7)	—	(28)
(LOSS) INCOME BEFORE INCOME TAXES	(262)	201	(5,476)
Income tax benefit	—	78	1,922
NET (LOSS) INCOME	(262)	279	(3,554)
Net income attributable to noncontrolling interest	(4)	—	—
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	$ (266)	$ 279	$ (3,554)
Net (loss) income attributable to common stock per share			
Basic and diluted	$ (6.26)	$ 6.76	$ (92.79)
Dividends per common share	$ —	$ —	$ 0.30

The accompanying notes are an integral part of these consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Comprehensive Income
For the years ended December 31, 2017, 2016 and 2015
(in millions)

	2017	2016	2015
Net (loss) income	$ (262)	$ 279	$ (3,554)
Other comprehensive (loss) income items:			
Pension and postretirement losses[(a)]	(14)	(9)	(2)
Reclassification to income of realized losses on pension and postretirement[(b)]	5	10	11
Total other comprehensive income, net of tax	(9)	1	9
Comprehensive income attributable to noncontrolling interest	—	—	—
Comprehensive (loss) income attributable to common stock	$ (271)	$ 280	$ (3,545)

(a) No associated tax for 2017 and 2016. Net of tax of $1 million for 2015. See *Note 13 Pension and Postretirement Benefit Plans*, for additional information.

(b) No associated tax for 2017 and 2016. Net of tax $(7) million for 2015. See *Note 13 Pension and Postretirement Benefit Plans*, for additional information.

The accompanying notes are an integral part of these consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Equity
For the years ended December 31, 2017, 2016 and 2015
(in millions)

	Common Stock	Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive (Loss) Income	Equity Attributable to Common Stock	Noncontrolling Interest	Total Equity
Balance, December 31, 2014	$ —	$ 4,752	$ (2,117)	$ (24)	$ 2,611	$ —	$ 2,611
Net loss	—	—	(3,554)	—	(3,554)	—	(3,554)
Other comprehensive income, net of tax	—	—	—	9	9	—	9
Dividends on common stock	—	—	(12)	—	(12)	—	(12)
Share-based compensation, net	—	30	—	—	30	—	30
Balance, December 31, 2015	$ —	$ 4,782	$ (5,683)	$ (15)	$ (916)	$ —	$ (916)
Net income	—	—	279	—	279	—	279
Other comprehensive income	—	—	—	1	1	—	1
Share-based compensation, net	—	79	—	—	79	—	79
Balance, December 31, 2016	$ —	$ 4,861	$ (5,404)	$ (14)	$ (557)	$ —	$ (557)
Net loss (income)	—	—	(266)	—	(266)	4	(262)
Contribution from noncontrolling interest, net	—	—	—	—	—	98	98
Distributions paid to noncontrolling interest holders	—	—	—	—	—	(8)	(8)
Other comprehensive income	—	—	—	(9)	(9)	—	(9)
Share-based compensation, net	—	18	—	—	18	—	18
Balance, December 31, 2017	$ —	$ 4,879	$ (5,670)	$ (23)	$ (814)	$ 94	$ (720)

The accompanying notes are an integral part of these consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows
For the years ended December 31, 2017, 2016 and 2015
(in millions)

	2017	2016	2015
CASH FLOW FROM OPERATING ACTIVITIES			
Net (loss) income	$ (262)	$ 279	$ (3,554)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	544	559	1,004
Asset impairments	—	—	4,852
Deferred income tax benefit	—	(78)	(2,258)
Net derivative losses (gains)	90	206	(133)
Net (payments) proceeds on settled derivatives	(7)	77	81
Net gains on early extinguishment of debt	(4)	(805)	(20)
Amortization of deferred gain	(74)	(71)	(3)
Gains on asset divestitures	(21)	(30)	—
Other non-cash tax provision	—	—	310
Other non-cash charges to income, net	77	101	210
Dry hole expenses	2	3	9
Changes in operating assets and liabilities, net:			
(Increase) decrease in trade receivables	(45)	(33)	99
Decrease in inventories	2	—	—
(Increase) decrease in other current assets	(2)	25	18
Decrease in accounts payable and accrued liabilities	(52)	(103)	(212)
Net cash provided by operating activities	248	130	403
CASH FLOW FROM INVESTING ACTIVITIES			
Capital investments	(371)	(75)	(401)
Changes in capital investment accruals	27	(6)	(205)
Asset divestitures	33	20	—
Acquisitions and other	(2)	—	(151)
Net cash used in investing activities	(313)	(61)	(757)
CASH FLOW FROM FINANCING ACTIVITIES			
Proceeds from 2014 Revolving Credit Facility	1,696	2,218	2,035
Repayments of 2014 Revolving Credit Facility	(2,180)	(2,110)	(1,656)
Proceeds from 2016 Credit Agreement	—	990	—
Proceeds from 2017 Term Loan	1,274	—	—
Payments on 2014 Term Loan	(650)	(350)	—
Debt repurchases	(116)	(770)	(12)
Debt transaction costs	(42)	(51)	(11)
Contribution from noncontrolling interest, net	98	—	—
Distributions paid to noncontrolling interest holders	(8)	—	—
Employee stock purchases and other	3	4	—
Shares canceled for taxes	(2)	—	—
Issuance of common stock	—	—	8
Cash dividends paid	—	—	(12)
Net cash provided (used) by financing activities	73	(69)	352
Increase (decrease) in cash	8	—	(2)
Cash—beginning of year	12	12	14
Cash—end of year	$ 20	$ 12	$ 12

The accompanying notes are an integral part of these consolidated financial statements.

NOTE 1 THE SPIN-OFF, SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND OTHER

The Separation and Spin-off

We are an independent oil and natural gas exploration and production company operating properties within California. We were incorporated in Delaware as a wholly owned subsidiary of Occidental Petroleum Corporation (Occidental) on April 23, 2014, and remained a wholly owned subsidiary of Occidental until November 30, 2014. On November 30, 2014, Occidental distributed shares of our common stock on a pro-rata basis to Occidental stockholders. We became an independent, publicly traded company (the Spin-off) on December 1, 2014. Occidental initially retained approximately 18.5% of our outstanding shares of common stock, which it distributed to Occidental stockholders on March 24, 2016.

Except when the context otherwise requires or where otherwise indicated, (1) all references to ''CRC,'' the ''Company,'' ''we,'' ''us'' and ''our'' refer to California Resources Corporation and its subsidiaries or the California business, (2) all references to the ''California business'' refer to Occidental's California oil and gas exploration and production operations and related assets, liabilities and obligations, which we have assumed in connection with the Spin-off, and (3) all references to ''Occidental'' refer to Occidental Petroleum Corporation, our former parent, and its subsidiaries.

Basis of Presentation

All financial information presented consists of our consolidated results of operations, financial position and cash flows. The assets and liabilities in the consolidated financial statements are presented on a historical cost basis. We have eliminated all of our significant intercompany transactions and accounts. We account for our share of oil and gas exploration and production ventures, in which we have a direct working interest, by reporting our proportionate share of assets, liabilities, revenues, costs and cash flows within the relevant lines on the balance sheets and statements of operations and cash flows.

As discussed more fully in *Note 3 Acquisitions and Divestitures*, we entered into a development joint venture with Benefit Street Partners (BSP) in 2017 in which we have a controlling financial interest. Therefore, the accounts of the BSP joint venture (BSP JV) are included in our accompanying consolidated financial statements beginning with the completion of the transaction. BSP's portion of net earnings and stockholders' equity is shown separately as a noncontrolling interest in the accompanying consolidated statements of operations and consolidated balance sheets, respectively. Our consolidated results reflect only our working interest share in our JV with Macquarie Infrastructure and Real Assets Inc. (MIRA JV).

Certain prior year amounts have been reclassified to conform to the 2017 presentation. On the statement of operations, we reclassified gains on asset divestitures out of other non-operating income (expense). On the statement of cash flows, we also moved gains on asset divestitures out of other non-cash charges to income, net.

On May 31, 2016, we completed a reverse stock split using a ratio of one share of common stock for every ten shares then outstanding. Share and per share amounts included in this report have been restated to reflect this reverse stock split. The split proportionally decreased the number of authorized shares of common stock from 2.0 billion shares to 200 million shares and preferred stock from

200 million to 20 million shares. The Compensation Committee of our Board approved proportionate adjustments to the number of shares outstanding and available for issuance under our stock-based compensation plans and to the exercise price, grant price or purchase price relating to any award under the plans, using the same reverse-split ratio, pursuant to existing authority granted to the Committee under the plans.

Risks and Uncertainties

The process of preparing financial statements in conformity with United States generally accepted accounting principles requires management to select appropriate accounting policies and make informed estimates and judgments regarding certain types of financial statement balances and disclosures. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements and judgments on expected outcomes as well as the materiality of transactions and balances. Changes in facts and circumstances or discovery of new information relating to such transactions and events may result in revised estimates and judgments and actual results may differ from estimates upon settlement. Management believes that these estimates and judgments provide a reasonable basis for the fair presentation of our financial statements.

Concentration of Customers

For the years ended December 31, 2017 and 2016, Phillips 66 Company, Andeavor (formerly Tesoro Refining & Marketing Company LLC), Valero Marketing & Supply Company and Shell Trading (US) Company each accounted for at least 10%, and, collectively, 67% of our revenue. For the year ended December 31, 2015, Phillips 66 Company, Tesoro Refining & Marketing Company LLC and Valero Marketing & Supply Company each accounted for more than 10%, and collectively, 64% of our revenue.

Critical Accounting Policies

Property, Plant and Equipment

We use the successful efforts method to account for our oil and gas properties. Under this method, we capitalize costs of acquiring properties, costs of drilling successful exploration wells and development costs. The costs of exploratory wells, including permitting, land preparation and drilling costs, are initially capitalized pending a determination of whether we find proved reserves. If we find proved reserves, the costs of exploratory wells remain capitalized. Otherwise, we charge the costs of the related wells to expense. In some cases, we cannot determine whether we have found proved reserves at the completion of exploration drilling, and must conduct additional testing and evaluation of the wells. We generally expense the costs of such exploratory wells if we do not determine we have found proved reserves within a 12-month period after drilling is complete.

Proved reserves are those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. We have no proved oil and gas reserves for which the determination of economic producibility is subject to the completion of major additional capital investments.

Several factors could change our proved oil and gas reserves. For example, for long-lived properties, higher product prices typically result in additional reserves becoming economic and lower product prices may lead to existing reserves becoming uneconomic. Estimation of future production and development costs is also subject to change partially due to factors beyond our control, such as energy costs and inflation or deflation of oil field service costs. These factors, in turn, could lead to changes in the quantity of proved reserves. Additional factors that could result in a change of proved reserves include production decline rates and operating performance differing from those estimated when the proved reserves were initially recorded as well as availability of capital to implement the development activities contemplated in the reserves estimates and changes in management's plans with respect to such development activities.

We perform impairment tests with respect to proved properties when product prices decline other than temporarily, reserves estimates change significantly, other significant events occur or management's plans change with respect to these properties in a manner that may impact our ability to realize the recorded asset amounts. Impairment tests incorporate a number of assumptions involving expectations of undiscounted future cash flows, which can change significantly over time. These assumptions include estimates of future product prices, which we base on forward price curves and, when applicable, contractual prices, estimates of oil and gas reserves and estimates of future expected operating and development costs. Any impairment loss would be calculated as the excess of the asset's net book value over its estimated fair value. We recognize any impairment loss on proved properties by adjusting the carrying amount of the asset.

A portion of the carrying value of our oil and gas properties is attributable to unproved properties. At December 31, 2017, the net capitalized costs attributable to unproved properties were approximately $300 million. When we make acquisitions that include unproved properties, we assign values based on estimated reserves that we believe will ultimately be proved. As exploration and development work progresses and if reserves are proved, we transfer the book value from unproved based on the initially determined rate, not based on specific areas, leases or other units. If the exploration and development work were to be unsuccessful, or management decided not to pursue development of these properties as a result of lower commodity prices, higher development and operating costs, contractual conditions or other factors, the capitalized costs of the related properties would be expensed. The unproved amounts are not subject to DD&A until they are classified as proved properties. As exploration and development work progresses, if reserves on these properties are proved, capitalized costs attributable to the properties become subject to DD&A.

Impairments of unproved properties are primarily based on qualitative factors including intent of property development, primary lease term and recent development activity. The timing of impairments on unproved properties, if warranted, depends upon management's plans, the nature, timing and extent of future exploration and development activities and their results. We recognize any impairment loss on unproved properties by providing a valuation allowance.

We determine depreciation and depletion of oil and gas producing properties by the unit-of-production method. We amortize acquisition costs over total proved reserves, and capitalize development and successful exploration costs over proved developed reserves. Our remaining assets are depreciated on a straight-line basis.

The most significant ongoing financial statement effect from a change in our proved oil and gas reserves or impairment of the carrying value of our proved properties would be to our DD&A rate. For example, a 5% increase or decrease in the amount of oil and gas reserves would change our DD&A rate by $0.61 per barrel, which would increase or decrease pre-tax income (loss) by $29 million annually based on production rates for the year ended December 31, 2017.

Asset Retirement Obligations

We recognize the fair value of asset retirement obligations in the period in which a determination is made that a legal obligation exists to dismantle an asset and reclaim or remediate the property at the end of its useful life and the cost of the obligation can be reasonably estimated. The liability amounts are based on future retirement cost estimates and incorporate many assumptions such as time of abandonment, technological changes, future inflation rates and the risk-adjusted discount rate. When the liability is initially recorded, we capitalize the cost by increasing the related PP&E balances. If the estimated future cost of the asset retirement obligation changes, we record an adjustment to both the asset retirement obligation and PP&E. Over time, the liability is increased and expense is recognized for accretion, and the capitalized cost is recovered over either the useful life of our facilities or the unit-of-production method for our minerals.

At certain of our facilities, we have identified asset retirement obligations that are related mainly to plant and field decommissioning, including plugging and abandonment of wells. In certain cases, we do not know or cannot estimate when we may settle these obligations and, therefore, we cannot reasonably estimate the fair value of these liabilities. We will recognize these asset retirement obligations in the periods in which sufficient information becomes available to reasonably estimate their fair values. Additionally, for certain plants, we do not have a legal obligation to decommission them and accordingly we have not recorded a liability.

The following table summarizes the activity of our asset retirement obligation, of which $403 million and $397 million is included in other long-term liabilities, with the remaining current portion in accrued liabilities at December 31, 2017 and 2016, respectively.

	For the years ended December 31,	
	2017	2016
	(in millions)	
Beginning balance	$ 411	$ 357
Liabilities incurred—capitalized to PP&E	2	2
Liabilities settled and paid	(9)	(10)
Accretion expense	25	22
Disposition and other—changes in PP&E	—	(17)
Revisions to estimated cash flows—changes in PP&E	(7)	57
Ending balance	$ 422	$ 411

Pension and Postretirement Benefit Plans

All of our employees participate in postretirement benefit plans sponsored by us. These plans are funded as benefits are paid. In addition, a small number of our employees also participate in defined benefit pension plans sponsored by us. We recognize the net overfunded or underfunded amounts in the financial statements using a December 31 measurement date.

We determine our defined benefit pension and postretirement benefit plan obligations based on various assumptions and discount rates. The discount rate assumptions used are meant to reflect the interest rate at which the obligations could effectively be settled on the measurement date. We estimate the rate of return on assets with regard to current market factors but within the context of historical returns.

Pension plan assets are measured at fair value. Publicly registered mutual funds are valued using quoted market prices in active markets. Commingled funds are valued at the fund units' net asset value

(NAV) provided by the issuer, which represents the quoted price in a non-active market. Guaranteed deposit accounts are valued at the book value provided by the issuer.

Actuarial gains and losses that have not yet been recognized through income are recorded in accumulated other comprehensive income within equity, net of taxes, until they are amortized as a component of net periodic benefit cost.

Fair Value Measurements

We have categorized our assets and liabilities that are measured at fair value in a three-level fair value hierarchy, based on the inputs to the valuation techniques: Level 1—using quoted prices in active markets for the assets or liabilities; Level 2—using observable inputs other than quoted prices for the assets or liabilities; and Level 3—using unobservable inputs. Transfers between levels, if any, are recognized at the end of each reporting period. We apply the market approach for certain recurring fair value measurements, maximize our use of observable inputs and minimize use of unobservable inputs. We generally use an income approach to measure fair value when observable inputs are unavailable. This approach utilizes management’s judgments regarding expectations of projected cash flows using a risk-adjusted discount rate.

Commodity derivatives are carried at fair value. We utilize the mid-point between bid and ask prices for valuing these instruments. In addition to using market data in determining these fair values, we make assumptions about the risks inherent in the inputs to the valuation technique. Our commodity derivatives comprise over-the-counter (OTC) bilateral financial commodity contracts, which are generally valued using industry-standard models that consider various inputs, including quoted forward prices for commodities, time value, volatility factors, credit risk and current market and contracted prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable data or are supported by observable prices at which transactions are executed in the marketplace. We classify these measurements as Level 2. The most significant items on our balance sheet that would be affected by recurring fair value measurements are derivatives. Based on the $133 million net derivative liability as of December 31, 2017, a 10% increase or decrease in their fair value would affect pre-tax earnings by approximately $13 million.

Our property, plant and equipment is written down to fair value if we determine that there has been an impairment in its value. The fair value is determined as of the date of the assessment using discounted cash flow models based on management’s expectations for the future. Inputs include estimates of future production, prices based on commodity forward price curves as of the date of the estimate, estimated future operating and development costs and a risk-adjusted discount rate.

The carrying amounts of cash and other on-balance sheet financial instruments, other than fixed-rate debt, approximate fair value.

Other Accounting Policies

Revenue Recognition

We recognize revenue from oil and natural gas production when delivery occurs and title has passed from us to the transportation company or the customer, as applicable. We recognize our share of revenues net of any royalties and other third-party share.

Inventories

Materials and supplies are valued at weighted-average cost and are reviewed periodically for obsolescence. Finished goods is primarily comprised of oil and NGLs, which are valued at the lower of cost or market. Inventories as of December 31, 2017 and 2016 consisted of the following:

	2017	2016
	(in millions)	
Materials and supplies	$ 53	$ 55
Finished goods	3	3
Total	$ 56	$ 58

Derivative Instruments

Our derivatives are carried at fair value and on a net basis when a legal right of offset exists with the same counterparty. Fair value gains and losses from derivative instruments are recognized on a net basis in our consolidated statements of operations. Unless otherwise indicated, we use the term "hedge" to describe derivative instruments that are designed to achieve our hedging program goals, even though they are not necessarily accounted for as cash-flow or fair-value hedges.

Stock-Based Incentive Plans

We have stockholder-approved stock-based incentive plans for certain employees and directors that are more fully described in *Note 10 Stock Compensation*.

Earnings Per Share

We compute basic and diluted earnings per share (EPS) using the two-class method required for participating securities. Certain restricted and performance stock awards are considered participating securities when such shares have non-forfeitable dividend rights at the same rate as common stock.

Under the two-class method, undistributed earnings allocated to participating securities are subtracted from net income attributable to common stock in determining net income available to common stockholders. In loss periods, no allocation is made to participating securities because the participating securities do not share in losses. For basic EPS, the weighted-average number of common shares outstanding excludes outstanding shares related to unvested restricted stock awards. For diluted EPS, the basic shares outstanding are adjusted by adding potentially dilutive securities.

Other Loss Contingencies

In the normal course of business, we are involved in lawsuits, claims and other environmental and legal proceedings and audits. We accrue reserves for these matters when it is probable that a liability has been incurred and the liability can be reasonably estimated. In addition, we disclose, if material, in aggregate, our exposure to loss in excess of the amount recorded on the balance sheet for these matters if it is reasonably possible that an additional material loss may be incurred. We review our loss contingencies on an ongoing basis.

Loss contingencies are based on judgments made by management with respect to the likely outcome of these matters and are adjusted as appropriate. Management's judgments could change based on new information, changes in, or interpretations of, laws or regulations, changes in management's plans or intentions, opinions regarding the outcome of legal proceedings, or other factors.

Income Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. Deferred tax assets are recognized when it is more-likely-than-not that they will be realized. We periodically assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets will not be realized.

We recognize the financial statement effects of tax positions when it is more-likely-than-not, based on the technical merits, that the position will be sustained upon examination by a tax authority. We recognize interest and penalties, if any, related to uncertain tax positions as a component of the income tax provision. No interest or penalties related to uncertain tax positions were recognized in the financial statements for the periods presented.

Production Sharing Type Contracts

Our share of production and reserves from operations in the Wilmington field is subject to contractual arrangements similar to production-sharing contracts (PSCs) that are in effect through the economic life of the assets. Under such contracts we are obligated to fund all capital and production costs. We record a share of production and reserves to recover a portion of such capital and production costs and an additional share for profit. Our portion of the production represents volumes: (i) to recover our partners' share of capital and production costs that we incur on their behalf, (ii) for our share of contractually defined base production and (iii) for our share of remaining production thereafter. We recover our share of capital and production costs, and generate returns, through our defined share of production from (ii) and (iii) above. These contracts do not transfer any right of ownership to us and reserves reported from these arrangements are based on our economic interest as defined in the contracts. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline assuming comparable capital investment and production costs. However, our net economic benefit is greater when product prices are higher. The contracts represented approximately 20% of our production for the year ended December 31, 2017.

In addition, in line with industry practice for reporting PSC-type contracts, we report 100% of operating costs under the PSCs in our consolidated statements of operations as opposed to reporting only our share of those costs. We report the proceeds from production designed to recover our partners' share of such costs (cost recovery) in our revenues. Our reported production volumes reflect only our share of the total volumes produced, including cost recovery, which is less than the total volumes produced under the PSCs. This difference in reporting full operating costs but only our net share of production inflates our operating costs per barrel, with an equal corresponding increase in revenues, with no effect on our net results.

Cash

Cash at December 31, 2017 included approximately $5 million that is restricted for distributions to BSP unless otherwise mutually agreed to by the parties. For more on this acquisition, see *Note 3 Acquisitions and Divestitures.*

Other Current Assets

Other current assets as of December 31, 2017 and 2016 consisted of the following:

	2017	2016
	(in millions)	
Amounts due from joint interest partners	$ 76	$ 51
Derivative assets from commodities contracts	23	39
Assets held for sale	12	19
Prepaid expenses	19	14
Other current assets	$ 130	$ 123

Accrued Liabilities

Accrued liabilities as of December 31, 2017 and 2016 consisted of the following:

	2017	2016
	(in millions)	
Derivative liabilities from commodities contracts	$ 154	$ 103
Greenhouse gas obligations	106	89
Accrued employee-related costs	86	91
Other	129	124
Accrued liabilities	$ 475	$ 407

Supplemental Cash Flow Information

We did not make U.S. federal and state income tax payments in 2017, 2016 or 2015. Interest paid, net of capitalized amounts, totaled approximately $393 million, $382 million and $350 million, respectively, for the years ended December 31, 2017, 2016 and 2015.

NOTE 2 ACCOUNTING AND DISCLOSURE CHANGES

Recently Issued Accounting and Disclosure Changes

In 2016, the Financial Accounting Standards Board (FASB) issued rules clarifying the revenue recognition standard issued in 2014. The new revenue recognition model is based on control, which differs from the previous model which was based on a transfer of risks and rewards. Under the new rules, revenue is recognized when a customer obtains control of promised goods or services in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. As a result, depending on where control transfers, certain fees for transportation, marketing and processing, which were previously netted against revenue, will prospectively be presented as expenses. We have not identified any changes to the timing of revenue recognition based on the requirements of the new rules. The new rules also require more detailed disclosures related to the nature, timing, amount and uncertainty of revenue and cash flows arising from contracts with customers. We will adopt these rules in the first quarter of 2018 and apply the modified retrospective approach.

In February 2016, the FASB issued rules requiring lessees to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months and to include qualitative and quantitative disclosures with respect to the amount, timing, and uncertainty of cash flows arising from leases. These rules will be effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with earlier application permitted. We are currently evaluating the impact of these rules on our financial statements.

In January 2017, the FASB issued rules that changed the definition of a business to assist entities with evaluating when a set of transferred assets and activities is a business. The rules are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. We do not expect the adoption of these rules to have a significant impact on our financial statements.

In March 2017, the FASB issued rules requiring employers that sponsor defined benefit plans for pensions and postretirement benefits to present the service cost component of net periodic benefit cost in the same income statement line item as other employee compensation costs arising from services rendered during the period. Only the service cost component will be eligible for capitalization in assets. Employers will present the other components of the net periodic benefit cost separately from the line item that includes the service cost and outside of any subtotal of operating income. The rules are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. We do not expect the adoption of these rules to have a significant impact on our financial statements.

In May 2017, the FASB issued rules to simplify the guidance on the modification of share-based payment awards. The amendments provide clarity on which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting prospectively. The rules are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. The new rules will be applied prospectively to any awards modified on or after the adoption date.

Recently Adopted Accounting and Disclosure Changes

In July 2015, the FASB issued rules requiring entities to measure inventory at the lower of cost or net realizable value. We adopted these rules in the first quarter of 2017 with no changes to our financial statements.

NOTE 3 ACQUISITIONS AND DIVESTITURES

2017

In February 2017, we divested non-core assets resulting in $32 million of proceeds and a $21 million gain.

In February 2017, we entered into a joint venture (JV) with BSP where BSP will contribute up to $250 million, subject to agreement of the parties, in exchange for a preferred interest in the BSP JV. The funds contributed by BSP are designated to be used to develop certain of our oil and gas properties. We contributed a net profits interest (NPI) in existing and future cash flow from such properties in exchange for a common interest in the JV. BSP is entitled to preferential distributions and, if BSP receives cash distributions equal to a predetermined threshold, the preferred interest is automatically redeemed in full with no additional payment. BSP funded two $50 million tranches in March and July 2017, which were net of a $2 million issuance fee. The $98 million net proceeds were used to fund capital investments of $96 million and the remainder for hedging activities. Proceeds from the NPI are used by the BSP JV to (1) pay quarterly minimum distributions to BSP, (2) pay for development costs within the project area, upon mutual agreement between members, and (3) make distributions to BSP until the predetermined threshold is achieved.

In April 2017, we entered into a JV with Macquarie Infrastructure and Real Assets Inc. (MIRA) under which MIRA will invest up to $300 million, subject to agreement of the parties, to develop certain of our oil and gas properties in exchange for a 90% working interest in the related properties (MIRA JV). MIRA will fund 100% of the development cost of such properties. Our 10% working interest reverts to 75% if MIRA receives cash distributions equal to a predetermined threshold return. MIRA initially committed $160 million, which is intended to be invested over two years. Of the committed amount, MIRA contributed $58 million for drilling projects in 2017, with additional funding of up to $96 million expected in 2018.

Our consolidated results reflect the full operations of our BSP JV, with BSP's share of net income and stockholders' equity being shown separately as a noncontrolling interest in the accompanying consolidated statements of operations and consolidated balance sheets, respectively. Our consolidated results reflect only our working interest share in our MIRA JV.

2016

During the year ended December 31, 2016, we divested non-core assets resulting in $20 million of proceeds and a $30 million gain.

2015

During the year ended December 31, 2015, we paid approximately $140 million to acquire certain producing and non-producing oil and gas properties, primarily in the San Joaquin basin.

NOTE 4 PROPERTY, PLANT AND EQUIPMENT

The carrying value of our property, plant and equipment (PP&E) represents the cost incurred to acquire or develop the asset, including any asset retirement obligations and capitalized interest, net of accumulated depreciation, depletion and amortization (DD&A) and any impairment charges. For assets acquired, initial PP&E cost is based on fair values at the acquisition date. Asset retirement obligations are capitalized and amortized over the lives of the related assets.

The following table summarizes the activity of capitalized exploratory well costs for the years ended December 31:

	2017	2016	2015
		(in millions)	
Balance—beginning of year	$ 4	$ 6	$ 4
Additions to capitalized exploratory well costs pending the determination of proved reserves	4	1	16
Reclassification to property, plant and equipment based on the determination of proved reserves	(2)	—	(5)
Capitalized exploratory well costs charged to expense	(2)	(3)	(9)
Balance—end of year	$ 4	$ 4	$ 6

We expense annual lease rentals; the costs of injection used in production and exploration; and geological, geophysical and seismic costs as incurred. Costs of maintenance and repairs are expensed as incurred, except that the costs of replacements that expand capacity or add proven oil and gas reserves are capitalized.

Our gas plant and power plant assets are depreciated over the estimated useful lives of the assets, using the straight-line method, with expected initial useful lives of the assets ranging from two to 30 years. Other non-producing property and equipment is depreciated using the straight-line method based on expected initial lives of the individual assets or group of assets ranging from two to 20 years.

No impairment charges were recorded in 2017 or 2016. In 2015, we recorded impairment charges on our properties, in part, based on year-end forward price curves, as well as assessing projects we determined we would not pursue in the foreseeable future given the then current environment. As a result, in the fourth quarter of 2015, we recorded pre-tax asset impairment charges of $4.9 billion on certain proved and unproved properties throughout our asset base. Approximately $100 million of the charge was related to unproved properties.

NOTE 5 DEBT

As of December 31, 2017 and 2016, our debt consisted of the following credit agreements, second lien notes and senior notes:

	Outstanding Principal (in millions)		Interest Rate	Maturity	Security
	2017	**2016**			
Credit Agreements					
2014 Revolving Credit Facility[a]	$ 363	$ 847	LIBOR plus 3.25%-4.00% ABR plus 2.25%-3.00%	June 30, 2021	Shared First-Priority Lien
2014 Term Loan	—	650	LIBOR plus 3.25%-4.00% ABR plus 2.25%-3.00%	June 30, 2021	Shared First-Priority Lien
2017 Credit Agreement	1,300	—	LIBOR plus 4.75% ABR plus 3.75%	December 31, 2022[b]	Shared First-Priority Lien
2016 Credit Agreement	1,000	1,000	LIBOR plus 10.375% ABR plus 9.375%	December 31, 2021	First-Priority Lien
Second Lien Notes					
Second Lien Notes	2,250	2,250	8%	December 15, 2022	Second-Priority Lien
Senior Notes					
5% Senior Notes due 2020	100	193	5%	January 15, 2020	Unsecured
5 ½% Senior Notes due 2021	100	135	5.5%	September 15, 2021	Unsecured
6% Senior Notes due 2024	193	193	6%	November 15, 2024	Unsecured
Total Debt—Principal Amount	5,306	5,268			
Less Current Maturities of Long-Term Debt	—	(100)			
Long-Term Debt—Principal Amount	$5,306	$5,168			

(a) Following the Ares JV transaction in February 2018, we have no outstanding principal balance on our 2014 Revolving Credit Facility. See *Note 14 Subsequent Event* for further information on the Ares JV.
(b) The 2017 Credit Agreement is subject to a springing maturity of 91 days prior to the maturity of our 2016 Credit Agreement if more than $100 million is outstanding at that time.

At December 31, 2017, deferred gain and issuance costs were $287 million net, consisting of $415 million of deferred gains offset by $128 million of deferred issuance costs and original issue discounts. The December 31, 2016 deferred gain and issuance costs were $397 million net, consisting of $489 million of deferred gains offset by $92 million of deferred issuance costs and original issue discounts.

Credit Agreements

2014 Revolving Credit Facility

In September 2014, we entered into a Credit Agreement with JPMorgan Chase Bank, N.A, as administrative agent, and certain other lenders. This credit agreement currently consists of a $1 billion senior revolving loan facility (2014 Revolving Credit Facility), which we are permitted to increase by up to $50 million if we obtain additional commitments from new or existing lenders. Previously this credit agreement included a term loan facility (2014 Term Loan) that was repaid in full in November 2017.

As of December 31, 2017, we had approximately $489 million of available borrowing capacity, before taking into account a $150 million month-end minimum liquidity requirement. Our 2014 Revolving Credit Facility also includes a sub-limit of $400 million for the issuance of letters of credit. As of December 31, 2017 and 2016, we had letters of credit of approximately $148 million and $130 million, respectively. These letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters.

Security – As of December 31, 2017, the lenders had a shared first-priority lien on a substantial majority of our assets, including our Elk Hills power plant and midstream assets. Following the formation of the Ares JV in February 2018, the Elk Hills power plant and certain other midstream assets are no longer subject to the shared first-priority lien. See *Note 14 Subsequent Event* for further information on the Ares JV.

Interest Rate – We can elect to borrow at either a London Interbank Offered Rate (LIBOR) rate or an alternate base rate (ABR), in each case plus an applicable margin. The ABR is equal to the highest of (i) the federal funds effective rate plus 0.50%, (ii) the administrative agent's prime rate and (iii) the one-month LIBOR rate plus 1.00%. The applicable margin is adjusted based on the borrowing base utilization percentage under the 2014 Revolving Credit Facility and will vary from (i) in the case of LIBOR loans, 3.25% to 4.00% and (ii) in the case of ABR loans, 2.25% to 3.00%. The unused portion of our commitments is subject to a commitment fee that ranges from 0.30% to 0.50% per annum. We also pay customary fees and expenses. Interest on ABR loans is payable quarterly in arrears. Interest on LIBOR loans is payable at the end of each LIBOR period, but not less than quarterly.

Maturity Date – Our 2014 Revolving Credit Facility matures on June 30, 2021. Previously this facility was subject to a springing maturity of 273 days prior to the maturity of each of our 2020 Notes or our 2021 Notes if more than $100 million of such notes were outstanding on such date. During the fourth quarter of 2017, we repurchased $65 million in principal amount of 2020 Notes and $35 million in principal amount of 2021 Notes which eliminated this springing maturity feature.

Amortization Payments – The 2014 Revolving Credit Facility does not include any obligation to make amortization payments. In November 2017, we paid the remaining balance of our 2014 Term Loan in the amount of $559 million. Prior to that, we made a $16 million prepayment on our 2014 Term Loan from the proceeds of non-core asset sales in February 2017. In 2016 and through the nine months ended September 30, 2017, we made scheduled quarterly payments of $25 million on our 2014 Term Loan for an aggregate amount of $175 million. In August 2016, we made a $250 million prepayment on our 2014 Term Loan from the proceeds of our 2016 Credit Agreement.

Borrowing Base – The borrowing base is redetermined each May 1 and November 1, and was mostly recently reaffirmed at $2.3 billion on November 1, 2017. The borrowing base is based upon a number of factors, including commodity prices and reserves, declines in which could cause our borrowing base to be reduced. Increases in our borrowing base require approval of at least 80% of our lenders while decreases or affirmations require a two-thirds approval, in each case as measured by relative commitment amount. We and the lenders (requiring a request from the lenders holding two-thirds of the commitments) each may request a special redetermination once in any period between three consecutive scheduled redeterminations. We will be permitted to have collateral released when both (i) our credit ratings are at least Baa3 from Moody's and BBB- from S&P, in each case with a stable or better outlook, and (ii) certain permitted liens securing other debt are released.

Financial Covenants – As of December 31, 2017, our financial performance covenants included a monthly minimum liquidity requirement of not less than $150 million and the following:

Ratio	Components[(a)]	Required Levels	Tested
Maximum leverage ratio	Ratio of indebtedness under our 2014 Revolving Credit Facility to trailing four-quarter Adjusted EBITDAX	Not greater than 1.90 to 1.00 through 2019 Not greater than 1.50 to 1.00 after 2019	Quarterly
Minimum interest coverage ratio	Ratio of Adjusted EBITDAX to consolidated cash interest charges	Not less than 1.20 to 1.00	Quarterly
Minimum asset coverage ratio	Ratio of PV-10 to first lien indebtedness	Not less than 1.20 to 1.00	Quarterly

(a) Refer to the terms of our credit agreements for more detailed descriptions of the components of our financial covenants.

Other Covenants – Our 2014 Revolving Credit Facility includes covenants that, among other things, restrict our ability to incur additional indebtedness, grant liens, make asset sales and investments, repay existing indebtedness, pay dividends to common stockholders, make subsidiary distributions and enter into transactions that would result in fundamental changes. Generally, these covenants include exceptions that allow us to pursue some of these activities in certain circumstances. In addition to these covenants, we must also apply cash on hand in excess of $150 million daily to repay amounts outstanding.

Except for dispositions to development JVs, we must generally apply all of the proceeds from the sale of assets included in our borrowing base to repay loans outstanding under our 2014 Revolving Credit Facility. With respect to the sale of non-borrowing base assets (other than the Elk Hills power plant), we must apply the net cash proceeds to repay outstanding loans as follows:

- 25% of such proceeds for all net cash proceeds received up to $500 million
- 50% of such proceeds for all net cash proceeds received between $500 million and $1 billion
- 75% of such proceeds for all net cash proceeds received in excess of $1 billion.

We are permitted to use the balance of the proceeds for general corporate purposes including acquisitions and to repurchase our Second Lien Notes and Senior Notes subject to certain conditions, including that any repurchase be at a 20% minimum discount to par, pro-forma compliance with our financial performance covenants and that we maintain minimum liquidity of $250 million following such repurchase.

Consistent with the terms of the 2014 Credit Facility, 50% of the proceeds of an Elk Hills power plant sale are required to be used to repay outstanding loans with the balance of the funds used as described above for non-borrowing base assets. In connection with the February 2018 Ares JV transaction, we used $297 million of the net proceeds to repay all of the then outstanding loans under our 2014 Revolving Credit Facility. See *Note 14 Subsequent Event* for further information on the Ares JV.

Prior Amendments – Our 2014 Revolving Credit Facility was most recently amended in November 2017. As part of that amendment, we repaid the $559 million balance of our 2014 Term Loan and modified the financial and other covenants of our 2014 Revolving Credit Facility.

2017 Credit Agreement

In November 2017, we entered into a $1.3 billion credit agreement with The Bank of New York Mellon Trust Company, N.A., as administrative agent, and certain other lenders (2017 Credit Agreement). The net proceeds were used to pay the $559 million remaining balance of our 2014 Term Loan, resulting in a loss on the early extinguishment of debt of $8 million, reduce the balance of our 2014 Revolving Credit Facility and pay accrued interest. The proceeds received were net of a $26 million original issue discount and $38 million in transaction costs. As of December 31, 2017, we had a $1.3 billion term loan outstanding under our 2017 Credit Agreement.

Security – Our 2017 Credit Agreement is secured by the same shared first-priority lien used to secure our 2014 Revolving Credit Facility.

Maturity Date – The loans mature on December 31, 2022, subject to a springing maturity of 91 days prior to the maturity of our 2016 Credit Agreement if more than $100 million is outstanding at that time. Previously these loans included a springing maturity of 91 days prior to the maturity of our 2020 Notes or our 2021 Notes if more than $100 million of such notes were outstanding on such date. During the fourth quarter of 2017, we repurchased $65 million in principal amount of 2020 Notes and $35 million in principal amount of 2021 Notes which eliminated the springing maturity feature in the 2017 Credit Agreement that was tied to those notes. Prepayment more than 90 days prior to maturity is subject to a 2% premium.

Financial and Other Covenants – We are required to maintain a first-lien asset coverage ratio of not less than 1.20 to 1.00 as of any June 30 and December 31. In addition, our 2017 Credit Agreement provides for customary covenants and events of default consistent with, or generally less restrictive than, the covenants in our 2014 Revolving Credit Facility, including limitations on additional indebtedness, liens, asset dispositions, investments and restricted payments and other negative covenants, in each case subject to certain limitations and exceptions.

2016 Credit Agreement

In August 2016, we entered into a $1 billion credit agreement with The Bank of New York Mellon Trust Company, N.A., as administrative agent, and certain other lenders (2016 Credit Agreement). The net proceeds from the 2016 Credit Agreement were used to (i) prepay $250 million of our 2014 Term Loan and (ii) reduce our 2014 Revolving Credit Facility by $740 million. The proceeds received were net of a $10 million original issue discount. As of December 31, 2017, we had a $1 billion term loan outstanding under our 2016 Credit Agreement.

Security – Our 2016 Credit Agreement is secured by a first-priority lien on a substantial majority of our assets but is second in collateral recovery to our 2014 Revolving Credit Facility and 2017 Credit Agreement.

Maturity Date – The loans mature on December 31, 2021. Previously these loans included a springing maturity of 91 days prior to the maturity of our 2020 Notes or our 2021 Notes if more than $100 million of such notes were outstanding on such date. During the fourth quarter of 2017, we repurchased $65 million in principal amount of 2020 Notes and $35 million in principal amount of 2021 Notes which eliminated the springing maturity feature in the 2016 Credit Agreement that was tied to those notes. Prepayment is subject to a variable make-whole amount prior to the fourth anniversary. Following the fourth anniversary, we may redeem at par.

Financial and Other Covenants – We are required to maintain a first–lien asset coverage ratio of not less than 1.20 to 1.00 as of any June 30 and December 31. Our 2016 Credit Agreement also includes other covenants that are substantially similar to our 2017 Credit Agreement.

Second Lien Notes

In December 2015, we issued $2.25 billion in aggregate principal amount of 8% senior secured second-lien notes due December 15, 2022 (Second Lien Notes). The Second Lien Notes were issued in exchange for $2.8 billion of our then outstanding Senior Notes. We recorded a deferred gain of approximately $560 million on the debt exchange, which is being amortized using the effective interest rate method over the term of our Second Lien Notes. We pay cash interest semiannually in arrears on June 15 and December 15.

Security – Our Second Lien Notes are secured on a junior-priority basis to the first-priority liens that secure the loans under our 2014 Revolving Credit Facility, 2017 Credit Agreement and 2016 Credit Agreement.

Financial and Other Covenants – The indenture includes covenants that, among other things, limit our ability to grant liens securing borrowed money (subject to certain exceptions) and restrict our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. The covenants are not, however, directly linked to measures of our financial performance. In addition, if we experience a “change of control triggering event” (as defined in the indenture), we will be required, unless we have exercised our right to redeem our Second Lien Notes, to offer to purchase our Second Lien Notes at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest. The indenture also restricts our ability to sell certain assets and to release collateral from liens securing our Second Lien Notes, unless the collateral is also released in compliance with our senior credit facilities.

Redemption – We may redeem our Second Lien Notes (i) prior to December 15, 2018, in whole or in part at a redemption price equal to 100% of the principal amount redeemed plus a make-whole amount and accrued and unpaid interest, (ii) between December 15, 2018 and 2020, in whole or in part at a fixed redemption price ranging from 104% to 102% of the principal amount redeemed plus accrued and unpaid interest and (iii) thereafter in whole or in part at a redemption price equal to 100% of the principal amount redeemed plus accrued and unpaid interest.

Senior Notes

In October 2014, we issued $5 billion in aggregate principal amount of our senior unsecured notes, including $1 billion of 5% notes due January 15, 2020 (2020 Notes), $1.75 billion of 5 ½% notes due September 15, 2021 (2021 Notes) and $2.25 billion of 6% notes due November 15, 2024 (2024 Notes and, collectively, Senior Notes). We used the net proceeds from the issuance of our Senior Notes to make a $4.95 billion cash distribution to Occidental in October 2014.

Repurchases and Exchanges – In 2015, we repurchased approximately $33 million in principal amount of our 2020 Notes for $13 million in cash. We also exchanged a substantial majority of our

Senior Notes for our Second Lien Notes in December 2015 as described above. In 2016, we repurchased over $1.5 billion in principal amount of our outstanding Senior Notes, primarily using drawings of $750 million on our 2014 Revolving Credit Facility and cash from operations. We also exchanged approximately 3.4 million shares of our common stock for $100 million in aggregate principal amount of our Senior Notes. In the first quarter of 2017, we purchased $28 million in aggregate principal amount of our 2020 Notes for $24 million in cash, resulting in a $4 million pre-tax gain. As described above, in the fourth quarter of 2017, we also repurchased $65 million and $35 million in aggregate principal amount of our 2020 Notes and our 2021 Notes, respectively, for $92 million in cash, resulting in an $8 million pre-tax gain.

Financial and Other Covenants – The indenture includes covenants that, among other things, limits our ability to grant liens securing borrowed money subject to certain exceptions and restricts our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. The covenants are not, however, directly linked to measures of our financial performance. In addition, if we experience a “change of control triggering event” (as defined in the indenture), we will be required, unless we have exercised our right to redeem our Senior Notes, to offer to purchase our Senior Notes at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest.

Redemption – We may redeem our Senior Notes prior to their maturity dates, in whole or in part, at a redemption price equal to 100% of the principal amount redeemed plus accrued and unpaid interest and, generally, a make-whole amount.

Other

At December 31, 2017, we were in compliance with all financial and other debt covenants.

All obligations under our 2014 Revolving Credit Facility, 2017 Credit Agreement and 2016 Credit Agreement (collectively, Credit Facilities) as well as our Second Lien Notes are guaranteed both fully and unconditionally and jointly and severally by all of our material wholly owned subsidiaries.

The terms and conditions of all of our indebtedness are subject to additional qualifications and limitations that are set forth in the relevant governing documents.

Principal maturities of long-term debt outstanding at December 31, 2017 are as follows (in millions):

2018	$	—
2019		—
2020		100
2021		1,890
2022		3,123
Thereafter		193
Total	$	5,306

We estimate the fair value of fixed-rate debt, which is classified as Level 1, based on prices from known market transactions for our instruments. The estimated fair value of our debt at December 31, 2017 and 2016, including the fair value of the variable-rate portion, was approximately $4.8 billion and $4.9 billion, respectively, compared to a carrying value of approximately $5.3 billion in both years. A one-eighth percent change in the variable interest rates on the borrowings under our Credit Facilities on December 31, 2017 would result in a $3 million change in annual interest expense.

NOTE 6 LEASE COMMITMENTS

We have entered into various operating lease agreements, mainly for office space, office equipment and field equipment. We lease assets when leasing offers greater operating flexibility. Lease payments are generally expensed as part of production costs or general and administrative expenses. At December 31, 2017, future net minimum lease payments for noncancelable operating leases (excluding oil and natural gas and other mineral leases, utilities, taxes, insurance and maintenance expense) totaled:

	Amount (in millions)
2018	$ 12
2019	11
2020	5
2021	4
2022	3
Thereafter	8
Total minimum lease payments	$ 43

Rental expense for operating leases was $13 million in both 2017 and 2016 and $11 million in 2015. Minimum future lease payments and rental income from subleases was immaterial in 2017, 2016 and 2015.

NOTE 7 LAWSUITS, CLAIMS, COMMITMENTS AND CONTINGENCIES

We, or certain of our subsidiaries, are involved, in the normal course of business, in lawsuits, environmental and other claims and other contingencies that seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2017 and 2016 were not material to our balance sheets as of such dates. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We have certain commitments under contracts, including purchase commitments for goods and services used in the normal course of business including pipeline capacity and rig termination costs. At December 31, 2017, total purchase obligations on a discounted basis were approximately $215 million, which included approximately $129 million, $33 million, $18 million, $4 million and $3 million that will be paid in 2018, 2019, 2020, 2021 and 2022, respectively. Included in these obligations is a commitment to invest approximately $84 million in evaluation and development activities for one of our oil and gas properties prior to the end of 2018. Any deficiency in meeting this capital investment obligation would need to be paid in cash. Our 2018 capital program includes development plans for these properties, and we expect to fulfill the minimum investment requirement.

We, our subsidiaries, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with the Spin-off, purchases and other transactions that they have entered into with us. These indemnities include indemnities made to Occidental against certain tax-related liabilities that may be incurred by Occidental relating to the Spin-off and liabilities related to operation of our business while it was still owned by Occidental. As of December 31, 2017, we are not aware of material indemnity claims pending or threatened against us.

We are currently under examination by the Internal Revenue Service for our U.S. federal income tax returns for the post-Spin-off period in 2014 and calendar year 2015. No significant issues have been raised to date. The U.S. federal income tax return for 2016 and the California franchise tax returns for 2014 through 2016 remain subject to examination.

NOTE 8 DERIVATIVES

We maintain a commodity hedging program to help protect our cash flows, margins and capital program from the volatility of commodity prices and to improve our ability to comply with the covenants under our credit facilities. We will continue to be strategic and opportunistic in implementing our hedging program as market conditions permit.

Derivatives are carried at fair value and on a net basis when a legal right of offset exists with the same counterparty. We apply hedge accounting when transactions meet specified criteria for cash-flow hedge treatment and management elects and documents such treatment. Otherwise, we recognize any fair value gains or losses, over the remaining term of the hedge instrument, in earnings in the current period.

As of December 31, 2017, we did not have any derivatives designated as hedges. Unless otherwise indicated, we use the term “hedge” to describe derivative instruments that are designed to achieve our hedging program goals, even though they are not necessarily accounted for as cash-flow or fair-value hedges. As part of our hedging program, we entered into a number of derivative transactions that resulted in the following Brent-based crude oil contracts as of December 31, 2017:

	Q1 2018	Q2 2018	Q3 2018	Q4 2018	FY 2019	FY 2020
Sold Calls:						
Barrels per day	10,400	10,400	16,100	16,100	1,000	500
Weighted-average price per barrel	$ 59.38	$ 59.37	$ 58.91	$ 58.91	$60.00	$60.00
Purchased Puts:						
Barrels per day	1,200	1,200	1,100	1,100	1,000	500
Weighted-average price per barrel	$ 45.82	$ 45.83	$ 45.83	$ 45.85	$45.84	$43.91
Sold Puts:						
Barrels per day	29,000	29,000	19,000	19,000	—	—
Weighted-average price per barrel	$ 45.00	$ 45.00	$ 45.00	$ 45.00	$ —	$ —
Swaps:						
Barrels per day	38,300	34,000(1)	19,000(2)	19,000(2)	—	—
Weighted-average price per barrel	$ 60.03	$ 60.00	$ 60.13	$ 60.13	$ —	$ —

Note: Additional hedges for 2018 and 2019 were put in place after December 31, 2017 that are not included in the table above.

(1) Certain of our counterparties have options to increase swap volumes by up to 19,000 barrels per day at a weighted-average price of $60.00 for the second quarter of 2018.

(2) Certain of our counterparties have options to increase swap volumes by up to 29,000 barrels per day at a weighted-average price of $60.50 for the second half of 2018.

As of December 31, 2017, a small portion of the crude oil derivatives in the table above were entered into by our BSP joint venture entity, including all of the 2019 and 2020 positions. This joint venture also entered into natural gas swaps for insignificant volumes for the period of February 2018 to July 2020.

The outcomes of the derivative positions are as follows:

- Sold calls – we make settlement payments for prices above the indicated weighted-average price per barrel.

- Purchased calls – we receive settlement payments for prices above the indicated weighted-average price per barrel.
- Purchased puts – we receive settlement payments for prices below the indicated weighted-average price per barrel.
- Sold puts – we make settlement payments for prices below the indicated weighted-average price per barrel.

From time to time, we may use combinations of these positions to increase the efficacy of our hedging program.

For the years ended December 31, 2017, 2016 and 2015, we recognized non-cash derivative (losses) gains of approximately \$(83) million, \$(283) million and \$52 million, respectively, from marking these contracts to market, which were included in revenues.

We did not have any cash-flow hedges in 2017 and 2016. The after-tax gains and losses recognized in, and reclassified to income from accumulated other comprehensive income (AOCI), for derivative instruments classified as cash-flow hedges for the year ended December 31, 2015, and the ending AOCI balances for each period were not material. The amount of the ineffective portion of cash-flow hedges was immaterial for the year ended December 31, 2015.

We had no fair-value hedges as of and during the years ended December 31, 2017, 2016 and 2015.

Fair Value of Derivatives

Our commodity derivatives are measured at fair value using industry-standard models with various inputs, including quoted forward prices, and are all classified as Level 2 in the required fair value hierarchy for the periods presented. The following table presents the fair values (at gross and net) of our outstanding derivatives as of December 31, 2017 and 2016 (in millions):

	December 31, 2017			
	Balance Sheet Classification	**Gross Amounts Recognized at Fair Value**	**Gross Amounts Offset in the Balance Sheet**	**Net Fair Value Presented in the Balance Sheet**
Assets				
Commodity Contracts	Other current assets	$ 39	$ (16)	$ 23
Commodity Contracts	Other assets	1	—	1
Liabilities				
Commodity Contracts	Accrued liabilities	(170)	16	(154)
Commodity Contracts	Other long-term liabilities	(3)	—	(3)
Total derivatives		$ (133)	$ —	$ (133)

	December 31, 2016			
	Balance Sheet Classification	**Gross Amounts Recognized at Fair Value**	**Gross Amounts Offset in the Balance Sheet**	**Net Fair Value Presented in the Balance Sheet**
Assets				
Commodity Contracts	Other current assets	$ 88	$ (49)	$ 39
Commodity Contracts	Other assets	25	(6)	19
Liabilities				
Commodity Contracts	Accrued liabilities	(152)	49	(103)
Commodity Contracts	Other long-term liabilities	(58)	6	(52)
Total derivatives		$ (97)	$ —	$ (97)

Counterparty Credit Risk

Our credit risk relates primarily to trade receivables and derivative financial instruments. Credit exposure for each customer is monitored for outstanding balances and current activity. For derivative swaps and options entered into as part of our hedging program, we are subject to counterparty credit risk to the extent the counterparty is unable to meet its settlement commitments. We actively manage this credit risk by selecting counterparties that we believe to be financially strong and continuing to monitor their financial health. Concentration of credit risk is regularly reviewed to ensure that counterparty credit risk is adequately diversified.

As of December 31, 2017, the substantial majority of the credit exposures related to our derivative financial instruments was with investment-grade counterparties. We believe exposure to credit-related losses at December 31, 2017 was not material and losses associated with credit risk have been insignificant for all years presented.

NOTE 9 INCOME TAXES

Income (loss) before income taxes, which is all domestic, was $(262) million, $201 million and $(5,476) million for the years ended December 31, 2017, 2016 and 2015, respectively. The provision (benefit) for federal, state and local income taxes consisted of the following:

For the years ended December 31,	United States Federal	State and Local	Total
		(in millions)	
2017			
Current	$ —	$ —	$ —
Deferred	—	—	—
	$ —	$ —	$ —
2016			
Current	$ —	$ —	$ —
Deferred	(66)	(12)	(78)
	$ (66)	$ (12)	$ (78)
2015			
Current	$ 255	$ 81	$ 336
Deferred	(1,961)	(297)	(2,258)
	$ (1,706)	$ (216)	$ (1,922)

Total income tax expense (benefit) differs from the amounts computed by applying the U.S. federal income tax rate to pre-tax income (loss) as follows:

	For the years ended December 31,		
	2017	2016	2015
U.S. federal statutory tax rate	(35)%	35%	(35)%
State income taxes, net	(6)	6	(5)
Decrease in U.S. federal corporate tax rate	91	—	—
Changes in tax attributes, net	(19)	—	—
Cancellation of debt income, net	—	(275)	—
Stock-based compensation, net	1	2	—
Valuation allowance, net	(33)	192	5
Other	1	1	—
Effective tax rate	—%	(39)%	(35)%

The Tax Cuts and Jobs Act (the Tax Act) was enacted on December 22, 2017. The Tax Act includes significant changes to U.S. income tax and related laws. In addition to the reduction in the top corporate tax rate, other provisions of the Tax Act include, but are not limited to, fully expensing the cost of acquired qualified property, subject to certain phase-out provisions, and limiting the interest expense deduction. We evaluated the provisions of the Tax Act, most of which are effective January 1, 2018, and determined that because of our tax-loss and valuation allowance position there will be no net current impact on our financial statements. Over the long term, the provisions are expected to be favorable to us when we begin to generate taxable income and should result in the deferral of cash tax payments from when they otherwise would have been due.

During 2017, our effective tax rate differed from the statutory tax rate of 35% due to (1) a 91% decrease related to a one-time adjustment of $240 million for the remeasurement of our net deferred tax asset as a result of the Tax Act, (2) a 19% increase related to enhanced oil recovery (EOR) tax credits, marginal well tax credits and other items and (3) a 6% increase related to state taxes. All of these items resulted in a corresponding change to our valuation allowance increasing our effective tax rate by 33%, because it is not more-likely-than-not that our net deferred tax asset is realizable.

In the first quarter of 2016, we reduced our valuation allowance due to our evaluation of our assets and liabilities at the time of our 2015 debt exchange, which generated $1.4 billion of cancellation of debt income (CODI) for tax purposes. Our evaluation indicated that our liabilities exceeded the value of our assets, both calculated in accordance with tax rules, enabling us to move the liability related to CODI to deferred tax liabilities. The resulting increase of our deferred tax liabilities that could be offset against deferred tax assets caused an $82 million reduction in the valuation allowance and resulted in a benefit of $78 million, net of $4 million in state tax. During the rest of 2016, we increased the valuation allowance by $480 million, which resulted in a net increase of the allowance by $398 million for the year. The net change in the valuation allowance had the effect of increasing our provision by $384 million, after $14 million in state taxes, which increased our effective tax rate by 192%. We concluded, on a more-likely-than-not basis, that we could not realize any of the deferred tax assets generated during 2016.

Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit use of existing deferred tax assets. A significant piece of evidence evaluated is a history of operating losses. Such evidence limits our ability to consider other evidence such as projections for growth. As of December 31, 2017, we concluded that we could not realize, on a more-likely-than-not basis, any of our deferred tax assets and there is not sufficient evidence to support the reversal of all or any portion of this allowance. Given our recent and anticipated future earnings trends, we do not believe any of the valuation allowance will be released within the next 12 months. The amount of the deferred tax assets considered realizable could however be adjusted if estimates or amounts of deferred tax liabilities change.

Cancellation of debt income

As a result of our 2015, 2016 and 2017 debt transactions and amendments, we generated CODI of $1.4 billion, $1.3 billion and $13 million, respectively ($2.7 billion in the aggregate), for both U.S. federal and California state tax purposes. These respective amounts were excluded from taxable income because we determined, in 2016, that our liabilities exceeded the value of our assets for tax purposes immediately prior to each of the deleveraging transactions. In exchange for this exclusion, tax rules require us to reduce the tax basis of our assets. Accordingly, we have reduced our net operating losses and the basis of property, plant and equipment by $1.2 billion for U.S. federal tax purposes and $1.9 billion for California tax purposes. We were not required to make any further reductions in those assets because, beyond this point, our liabilities would have exceeded the tax basis of our assets. Accordingly, any tax liability attributable to the remaining approximately $1.5 billion of federal and $800 million of California CODI was relieved without any future tax liability, which reduced our effective rate by 275%.

The tax effects of temporary differences resulting in deferred income taxes at December 31, 2017 and 2016 were as follows:

	2017		2016	
	Deferred Tax Assets	Deferred Tax Liabilities	Deferred Tax Assets	Deferred Tax Liabilities
	(in millions)			
Debt	$ 324	$ —	$ 693	$ —
Property, plant and equipment differences	33	(261)	60	(335)
Postretirement benefit accruals	33	—	45	—
Deferred compensation and benefits	53	—	74	—
Asset retirement obligations	126	—	183	—
Federal effect of state income taxes	—	—	—	—
Net operating loss carryforwards and credits	417	—	61	—
All other	22	(41)	39	(40)
Subtotal	1,008	(302)	1,155	(375)
Valuation allowance	(706)	—	(780)	—
Total net deferred taxes	$ 302	$ (302)	$ 375	$ (375)

Prior to the Spin-off date, we were included in the Occidental income tax returns for all applicable years. Under the tax sharing agreement, Occidental controls tax examinations for the periods in which we were included in a consolidated or combined income tax return filed by Occidental. There were no amounts due to Occidental as of December 31, 2017 and 2016 under the tax sharing agreement.

Tax benefits are recognized only for tax positions that are more-likely-than-not to be sustained upon examination by tax authorities. The amount recognized is measured as the largest amount of benefit that is greater than 50 percent likely to be realized upon settlement. A liability for unrecognized tax benefits is recorded for any tax benefits claimed in the Company's tax returns that do not meet these recognition and measurement standards. As of December 31, 2017 and 2016, we recorded a $25 million liability for tax positions taken in prior periods which has been classified as a deferred tax liability. This amount of unrecognized tax benefit, if recognized, would affect the effective tax rate positively. We believe there will not be significant increases or decreases to our unrecognized tax benefits within the next 12 months.

As of December 31, 2017, we had a U.S. federal net operating loss carryforward of $1.1 billion and $1.9 billion of net operating loss carryforwards in California. The U.S. federal net operating loss carryforward expires in 2037. The California net operating loss carryforwards began expiring in 2026. A portion of the California net operating loss carryforwards resulted from acquisitions in prior years and is subject to an annual limitation. Accordingly, no financial statement benefit has been recognized for $88 million of the California net operating loss carryforwards. The deduction and carryforward period for the U.S. federal net operating loss generated in 2017 are unchanged by the Tax Act.

During 2017, we generated $27 million of U.S federal credits primarily related to EOR projects and marginal well credits. We also generated an $8 million California credit related to EOR projects. The U.S. federal and California credits begin expiring in 2037.

NOTE 10 STOCK COMPENSATION

General

Effective May 2016, our stockholders approved the California Resources Corporation Long-Term Incentive Plan (the Plan), which provides for the issuance of incentive and non-qualified stock options, restricted stock awards, restricted stock units, stock appreciation rights, stock bonuses, performance-based awards and other awards to officers, employees and non-employee directors. The maximum number of authorized shares of our common stock that may be issued pursuant to our long-term incentive plan is 4.7 million shares. As of December 31, 2017, 3.6 million shares were issued or reserved under the Plan and 1.1 million shares were available for future issuance of awards under the Plan. Our incentive compensation program is administered by the Compensation Committee of our Board of Directors.

Compensation expense for stock-based awards for the year ended December 31, 2017 was $29 million, of which $22 million was included in general and administrative expenses and $7 million was included in production costs in our consolidated statement of operations. Compensation expense for stock-based awards for the year ended December 31, 2016 was $34 million, of which $27 million was included in general and administrative expenses and $7 million was included in production costs in our consolidated statement of operations. Compensation expense for stock-based awards for the year ended December 31, 2015 was $37 million, of which $28 million was included in general and administrative expenses and $9 million was included in production costs in our consolidated statement of operations. For the years ended December 31, 2017 and 2016, we did not recognize any income tax benefit related to our stock-based compensation. For the year ended December 31, 2015, we recognized income tax expense of approximately $2 million. For the years ended December 31, 2017, 2016 and 2015, we made cash payments of $6 million, $5 million and $10 million for the cash-settled portion of our awards, respectively.

As of December 31, 2017, unrecognized compensation expense for all our unvested stock-based incentive awards, based on the year-end value of our common stock, was $40 million. This expense is expected to be recognized over a weighted-average period of two years.

Restricted Stock

Certain employees and non-employee directors are granted restricted stock units (RSUs) or restricted stock awards (RSAs) which are in the form of, or equivalent in value to, actual shares of our common stock. Restricted stock is service-based and, depending on the terms of the grants, is settled in cash or stock at the time of vesting. The service-based awards vest ratably over three years or at the end of three years for employees and one year for directors following the date of grant. Our RSUs and RSAs have nonforfeitable dividend rights, and any dividends or dividend equivalents declared during the vesting period are paid as declared.

For cash- and stock-settled RSUs and RSAs, compensation value is initially measured on the grant date using the quoted market price of our common stock. Compensation expense for cash-settled RSUs is adjusted on a quarterly basis for the cumulative change in the value of the underlying stock. Compensation expense for the stock-settled RSUs and RSAs is recognized on a straight-line basis over the requisite service periods, adjusted for actual forfeitures.

The following summarizes our restricted stock activity for the year ended December 31, 2017:

	Stock-Settled		Cash-Settled
	Number of Awards and Units (in thousands)	Weighted-Average Grant-Date Fair Value	Number of Units (in thousands)
Unvested at January 1	682	$ 20.90	1,580
Granted	718	$ 16.20	1,184
Vested	(337)	$ 25.97	(597)
Forfeited	(28)	$ 18.41	(101)
Unvested at December 31	**1,035**	**$ 16.04**	**2,066**

Note: During 2017 and 2016, our directors were granted stock-settled RSUs representing approximately 98,000 shares and 77,000 shares, respectively.

Performance Stock Unit Awards

Our performance stock units (PSUs) granted prior to 2015 are RSAs with a performance target based on cumulative earnings before interest, taxes and depreciation. The units vest at the later of the three years following the grant date or when the performance target is met, if prior to seven years following the grant date. Fair value was based on Occidental's stock price on the grant date divided by a conversion factor used at the time of the Spin-off. The resulting fair value was recognized as compensation expense on a straight-line basis over the three-year service period, adjusted for actual forfeitures. These awards have nonforfeitable dividend rights with any dividends or dividend equivalents declared during the vesting period paid as declared.

The PSUs granted in 2015 are RSUs based 50% on achievement of specified Value Creation Index (VCI) results and 50% on total stockholder return (TSR) relative to a selected peer group of companies over specified multi-year performance periods, with payouts ranging from 0% to 200% of the target award. The awards were originally granted as cash-settled awards accounted for as liability awards until they were modified in May 2016 and became stock-settled awards accounted for as equity awards from that point forward. Less than 50 people were impacted by this modification, which resulted in no incremental compensation cost.

Prior to the modification, the fair value of the VCI-based portions of the PSUs was determined on the grant date based on an estimated performance achievement at the target level. Additionally, the fair value of the TSR-based portions of the PSUs was determined on the grant date using a Monte Carlo simulation model based on applicable assumptions. The volatility is derived from corresponding peer group companies, which we used in the absence of adequate stock price history for our common stock at the date of grant. The expected life is based on the vesting period of the award. The risk-free rate is the implied yield available on zero-coupon U.S. Treasury notes at the time of grant and subsequent measurement periods with a remaining term equal to the remaining term of the awards. The dividend yield is the expected annual dividend yield over the term, expressed as a percentage of the stock price on the valuation date. The fair values were then recognized on a straight-line basis over the requisite service period, adjusted for actual forfeitures. Compensation expense was adjusted quarterly, on a cumulative basis, for any changes in the number of share equivalents expected to be paid based on the relevant performance criteria.

On the modification date, the fair value of the PSUs was redetermined based on target-level VCI and TSR Monte Carlo results as of that date. The resulting fair value is being recognized as compensation expense on a straight-line basis over the remaining requisite service period, adjusted for actual forfeitures. Dividend equivalents, if any, declared during the vesting period are accumulated and paid upon certification for the number of vested shares.

The modification and grant date assumptions used in the Monte Carlo valuation for the TSR-based portion of the outstanding PSU awards are as follows:

	Modification Date	Grant Date
Risk-free interest rate	0.77%	1.06%
Dividend yield	—%	0.95%
Volatility factor	69.69%	43.63%
Expected life (years)	2.16	2.9
Fair value of underlying common stock	$ 18.50	$ 42.00

The following summarizes our PSU activity for the year ended December 31, 2017:

	Stock-Settled	
	Number of Awards (in thousands)	Weighted-Average Grant-Date Fair Value
Unvested at January 1	459	$ 44.34
Granted	—	$ —
Vested	(72)	$ 73.70
Forfeited	(3)	$ 18.50
Unvested at December 31	**384**	**$ 39.05**

Stock Options

In 2014 and 2015, we granted stock options to certain executives under our long-term incentive plan. The options permit purchase of our common stock at exercise prices no less than the fair market value of the stock on the date the options were granted. The options have terms of seven years and vest ratably over three years, with one third of the granted shares becoming exercisable on each anniversary date following the date of grant, subject to certain restrictions including continued employment. No stock options were issued during 2017 and 2016.

The fair value of stock options is measured on the grant date using the Black-Scholes option valuation model and expensed on a straight-line basis over the vesting period. The model uses various assumptions, based on management's estimates at the time of grant, which impact the calculation of fair value and ultimately the amount of expense recognized over the vesting period of the stock option award. The expected life of stock options is calculated based on the simplified method and represents the period of time that options granted are expected to be held prior to exercise. In the absence of adequate stock price history of our common stock at the time of grant, the volatility factor was based on the average volatilities of the stocks of a select group of peer companies. The risk-free interest rate is the implied yield available on zero-coupon United States (U.S.) Treasury notes at the grant date with a remaining term approximating the expected life. The dividend yield is the expected annual dividend yield over the expected life, expressed as a percentage of the stock price on the grant date. Of the required assumptions, the expected life of the stock option award and the expected volatility have the most significant impact on the fair value calculation.

The grant date assumptions used in the Black-Scholes valuation for options granted during 2015 and 2014 were as follows:

	2015	2014
Exercise price per share	$ 42.00	$ 81.10
Expected life (in years)	4.5	4.5
Expected volatility	44.7%	35.4%
Risk-free interest rate	1.56%	1.40%
Dividend yield	0.95%	0.50%
Grant date fair value of stock option awards granted	$ 15.00	$ 19.80

The following table summarizes our option activity during the year ended December 31, 2017:

	Options (000's)	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Aggregate Intrinsic Value
Beginning balance, January 1	1,109	$ 69.89	$ 18.42	$ —
Granted	—	$ —	$ —	$ —
Exercised	—	$ —	$ —	$ —
Forfeited	(4)	$ 54.12	$ 16.49	$ —
Ending balance, December 31	**1,105**	**$ 69.95**	**$ 18.43**	**$ —**
Exercisable at December 31	**1,013**	**$ 72.47**	**$ 18.74**	**$ —**

Employee Stock Purchase Plan

Effective January 1, 2015, we adopted the California Resources Corporation 2014 Employee Stock Purchase Plan (ESPP), which was subsequently amended in May 2016. The ESPP provides our employees the ability to purchase shares of our common stock at a price equal to 85% of the closing price of a share of our common stock as of the first or last day of each offering period (a fiscal quarter), whichever amount is less.

The maximum number of shares of our common stock that may be issued pursuant to the ESPP is subject to certain annual limits and has a cumulative limit of one million shares, subject to adjustment pursuant to the terms of the ESPP. For the year ended December 31, 2017, we issued approximately 0.2 million shares of common stock in connection with our ESPP.

NOTE 11 EQUITY

The following is a summary of common stock issuances on a post-split basis:

	Common Stock (in thousands)
Balance, December 31, 2015	38,818
Issued	3,725
Balance, December 31, 2016	42,543
Issued	359
Balance, December 31, 2017	42,902

At December 31, 2017 and 2016, we had 200 million authorized shares of common stock and 20 million authorized shares of preferred stock, both with a $0.01 par value per share, and no outstanding shares of preferred stock on either date.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) consisted of pension and post-retirement losses of $23 million and $14 million, at December 31, 2017 and 2016, respectively.

NOTE 12 EARNINGS PER SHARE

The following table presents the calculation of basic and diluted EPS for the years ended December 31:

	2017	2016	2015
	(in millions, except per-share amounts)		
Basic EPS calculation			
Net (loss) income	$ (262)	$ 279	$ (3,554)
Less: net income attributable to noncontrolling interest	(4)	—	—
Net (loss) income attributable to common stock	(266)	279	(3,554)
Less: net income allocated to participating securities	—	(6)	—
Net (loss) income available to common stockholders	$ (266)	$ 273	$ (3,554)
Weighted-average common shares outstanding—basic	42.5	40.4	38.3
Basic EPS	$ (6.26)	$ 6.76	$ (92.79)
Diluted EPS calculation			
Net income (loss)	$ (262)	$ 279	$ (3,554)
Less: net income attributable to noncontrolling interest	(4)	—	—
Net (loss) income attributable to common stock	(266)	279	(3,554)
Less: net income allocated to participating securities	—	(6)	—
Net (loss) income available to common stockholders	$ (266)	$ 273	$ (3,554)
Weighted-average common shares outstanding—basic	42.5	40.4	38.3
Dilutive effect of potentially dilutive securities	—	—	—
Weighted-average common shares outstanding—diluted	42.5	40.4	38.3
Diluted EPS	$ (6.26)	$ 6.76	$ (92.79)
Weighted-average anti-dilutive shares[a]	2.1	1.7	1.3

(a) Anti-dilutive shares represent potentially dilutive securities that are excluded from the computation of diluted EPS due to our net loss position. Anti-dilutive shares include the effect of out-of-the-money stock options and exclude the performance stock units issued in 2015.

NOTE 13 PENSION AND POSTRETIREMENT BENEFIT PLANS

We have various qualified and non-qualified benefit plans for our salaried and union and nonunion hourly employees.

Defined Contribution Plans

All of our employees are eligible to participate in our defined contribution retirement plan that provides for periodic contributions by us based on plan-specific criteria, such as eligible pay and employee contributions.

Certain salaried employees participate in supplemental plans that restore benefits lost due to governmental limitations on qualified plans. As of December 31, 2017 and 2016, we recognized $32 million and $31 million in other long-term liabilities for these supplemental plans.

We expensed $33 million in 2017, $32 million in 2016 and $39 million in 2015 under the provisions of these defined contribution and supplemental plans.

Defined Benefit Plans

Participation in defined benefit pension plans sponsored by us is limited. During 2017, approximately 70 employees accrued benefits under these plans, all of whom were union employees. Effective December 31, 2015, the plans were amended such that participants other than union employees no longer earn benefits for service after December 31, 2015.

Pension costs for the defined benefit pension plans, determined by independent actuarial valuations, are funded by us through payments to trust funds, which are administered by independent trustees.

Postretirement Benefit Plans

We provide postretirement medical and dental benefits for our eligible former employees and their dependents. The benefits are funded by us and required contributions from former employees as claims are paid during the year.

Obligations and Funded Status of our Defined Benefit Plans

The following tables show the amounts recognized in our balance sheets related to pension and postretirement benefit plans, as well as plans that we or our subsidiaries sponsor, and their funding status, obligations and plan asset fair values:

	As of December 31,			
	2017	2016	2017	2016
	Pension Benefits		Postretirement Benefits	
	(in millions)			
Amounts recognized in the balance sheet:				
Accrued liabilities	$ —	$ —	$ (3)	$ (2)
Other long-term liabilities	(19)	(26)	(90)	(75)
	$ (19)	$ (26)	$ (93)	$ (77)
Amounts recognized in accumulated other comprehensive (loss) income:	$ (13)	$ (16)	$ (10)	$ 2

	As of December 31,			
	2017	2016	2017	2016
	Pension Benefits		Postretirement Benefits	
	(in millions)			
Changes in the benefit obligation:				
Benefit obligation—beginning of year	$ 70	$ 83	$ 77	$ 71
Service cost—benefits earned during the period	1	1	3	3
Interest cost on projected benefit obligation	2	3	4	3
Actuarial loss	7	7	11	1
Benefits paid	(15)	(24)	(2)	(1)
Benefit obligation—end of year	$ 65	$ 70	$ 93	$ 77
Changes in plan assets:				
Fair value of plan assets—beginning of year	$ 44	$ 56	$ —	$ —
Actual return on plan assets	5	2	—	—
Employer contributions	12	10	2	1
Benefits paid	(15)	(24)	(2)	(1)
Fair value of plan assets—end of year	$ 46	$ 44	$ —	$ —
Unfunded status	$ (19)	$ (26)	$ (93)	$ (77)

The following table sets forth our defined benefit pension plans with accumulated benefit obligations in excess of plan assets for the years ended December 31:

	2017	2016
	(in millions)	
Projected Benefit Obligation	$ 65	$ 70
Accumulated Benefit Obligation	$ 62	$ 67
Fair Value of Plan Assets	$ 46	$ 44

None of our defined benefit pension plans had plan assets in excess of accumulated benefit obligations. We do not expect any plan assets to be returned during 2018.

Components of Net Periodic Benefit Cost

The following tables set forth our pension and postretirement benefit costs and amounts recognized in other comprehensive income (before tax):

	For the years ended December 31,					
	2017	2016	2015	2017	2016	2015
	Pension Benefits			Postretirement Benefits		
	(in millions)					
Net periodic benefit costs:						
Service cost—benefits earned during the period	$ 1	$ 1	$ 4	$ 3	$ 3	$ 5
Interest cost on projected benefit obligation	2	3	4	4	3	3
Expected return on plan assets	(3)	(3)	(5)	—	—	—
Amortization of net actuarial loss	2	2	3	—	—	—
Settlement cost	5	8	18	—	—	—
Curtailment loss	—	—	—	—	—	5
Net periodic benefit cost	$ 7	$ 11	$ 24	$ 7	$ 6	$ 13

	For the years ended December 31,					
	2017	2016	2015	2017	2016	2015
	Pension Benefits			Postretirement Benefits		
	(in millions)					
Amounts recognized in other comprehensive income (loss):						
Net actuarial (loss) gain	$ (4)	$ (9)	$ (28)	$ (12)	$ —	$ 9
Net prior service credit	—	—	12	—	—	—
Settlement cost	5	8	18	—	—	—
Amortization of net actuarial gain/loss	2	2	3	—	—	—
Total recognized in other comprehensive income (loss)	$ 3	$ 1	$ 5	$ (12)	$ —	$ 9

Settlement costs related to our pension plans were associated with early retirements. The curtailment loss in 2015 related to employee reductions.

The estimated net actuarial loss and prior service credit for the defined benefit pension plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year are $2 million and $0, respectively. We do not expect to have any estimated net actuarial loss or prior service cost for the defined benefit postretirement plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year.

The following table sets forth the weighted-average assumptions used to determine our benefit obligations and net periodic benefit cost:

	For the years ended December 31,			
	2017	2016	2017	2016
	Pension Benefits		Postretirement Benefits	
Benefit Obligation Assumptions:				
Discount rate	3.53%	3.88%	3.87%	4.58%
Rate of compensation increase	4.00%	4.00%	—	—
Net Periodic Benefit Cost Assumptions:				
Discount rate	3.88%	3.99%	4.58%	4.81%
Assumed long-term rate of return on assets	6.50%	6.50%	—	—
Rate of compensation increase	4.00%	4.00%	—	—

For pension plans and postretirement benefit plans that we or our subsidiaries sponsor, we based the discount rate on the Aon/Hewitt AA Above Median yield curve in both 2017 and 2016. The weighted-average rate of increase in future compensation levels is consistent with our past and anticipated future compensation increases for employees participating in retirement plans that determine benefits using compensation. The assumed long-term rate of return on assets is estimated with regard to current market factors but within the context of historical returns for the asset mix that exists at year end.

Effective in 2017, we adopted the Society of Actuaries MP-2017 Mortality Improvement Scale, which updated the Society of Actuaries Adjusted RP-2014 mortality assumptions that private defined benefit pension plans in the United States use in the actuarial valuations that determine a plan sponsor's pension and postretirement obligations. In 2016, we utilized the Society of Actuaries Adjusted RP-2014 Mortality Table reflecting the MP-2016 Mortality Improvement Scale. At December 31, 2017, the changes in the mortality assumptions resulted in no significant change to the pension benefit obligations and a decrease of $1 million in the postretirement benefit obligations.

The postretirement benefit obligation was determined by application of the terms of medical and dental benefits, including the effect of established maximums on covered costs, together with relevant actuarial assumptions and healthcare cost trend rates projected at an assumed U.S. Consumer Price Index (CPI) increase of 1.97% as of December 31, 2017 and 2016. Under the terms of our postretirement plans, participants other than certain union employees pay for all medical cost increases in excess of increases in the CPI. For those union employees, we projected that, as of December 31, 2017, healthcare cost trend rates would decrease 0.25 percent per year from 7.00% in 2018 until they reach 6.00% in 2022, then decrease 0.50 percent per year until they reach 4.50% in 2025, and remain at 4.50% thereafter. A one-percent increase or a one-percent decrease in these assumed healthcare cost trend rates would result in an increase of $5 million or a reduction of $4 million, respectively, in the postretirement benefit obligation as of December 31, 2017. The annual service and interest costs would not be materially affected by these changes.

The actuarial assumptions used could change in the near term as a result of changes in expected future trends and other factors that, depending on the nature of the changes, could cause increases or decreases in the plan assets and liabilities.

Fair Value of Pension Plan Assets

We employ a total return investment approach that uses a diversified blend of equity and fixed-income investments to optimize the long-term return of plan assets at a prudent level of risk. Equity investments were diversified across U.S. and non-U.S. stocks, as well as differing styles and market capitalizations. Other asset classes, such as private equity and real estate, may have been used with the goals of enhancing long-term returns and improving portfolio diversification. In 2017 and 2016, the target allocation of plan assets was 65% equity securities and 35% debt securities. Investment performance was measured and monitored on an ongoing basis through quarterly investment portfolio and manager guideline compliance reviews, annual liability measurements and periodic studies.

The fair values of our pension plan assets by asset category are as follows:

	Fair Value Measurements at December 31, 2017 Using			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Asset Class:				
Cash equivalents	$ 3	$ —	$ —	$ 3
Commingled funds:				
Fixed income	—	7	—	7
U.S. equity	—	9	—	9
International equity	—	5	—	5
Mutual funds:				
Bond funds	6	—	—	6
Blend funds	3	—	—	3
Value funds	3	—	—	3
Growth funds	3	—	—	3
Guaranteed deposit account	—	—	7	7
Total pension plan assets	$ 18	$ 21	$ 7	$ 46

	Fair Value Measurements at December 31, 2016 Using			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Asset Class:				
Cash equivalents	$ 3	$ —	$ —	$ 3
Commingled funds:				
Fixed income	—	9	—	9
U.S. equity	—	10	—	10
International equity	—	6	—	6
Mutual funds:				
Bond funds	4	—	—	4
Blend funds	2	—	—	2
Value funds	2	—	—	2
Growth funds	2	—	—	2
Guaranteed deposit account	—	—	6	6
Total pension plan assets	$ 13	$ 25	$ 6	$ 44

The activity during the years ended December 31, 2017 and 2016, for the assets using Level 3 fair value measurements was insignificant.

Expected Cash Flows

In 2018, we plan to contribute $3 million to our postretirement benefit plans and at least our minimum funding requirement of $4 million to our defined benefit pension plans. Estimated future undiscounted benefit payments, which reflect expected future service, as appropriate, are as follows:

For the years ended December 31,	Pension Benefits	Postretirement Benefits
	(in millions)	
2018	$ 21	$ 3
2019	$ 5	$ 3
2020	$ 5	$ 4
2021	$ 5	$ 4
2022	$ 4	$ 4
2023 - 2027	$ 16	$ 23

NOTE 14 SUBSEQUENT EVENT

In February 2018, we entered into a midstream JV with ECR Corporate Holdings L.P. (ECR), a portfolio company of Ares Management L.P. (Ares). This JV (Ares JV) holds the Elk Hills power plant, the 550 megawatt natural gas fired power plant, and the 200 million cubic foot per day cryogenic gas processing plant. Through one of our wholly owned subsidiaries, we hold 50% of the Class A common interest and 95.25% of the Class C common interest in the Ares JV. ECR holds 50% of the Class A common interest, 100% of the Class B preferred interest and 4.75% of the Class C common interest in the Ares JV. At closing, in accordance with the terms of our credit agreement, we used $297 million of the $747 million in net proceeds to pay off the then outstanding balance of our 2014 Revolving Credit Facility.

We will consolidate the Ares JV in our financial statements and reflect the Class A common interest and Class B preferred interest as noncontrolling interest in mezzanine equity and the Class C common interest in equity on our balance sheet. Net income allocable to ECR will be reported as income attributable to noncontrolling interest. Distributions will be paid to the preferred interest on a priority basis with the remaining cash distributed pro-rata to the common interests.

In February 2018 and in connection with the formation of the Ares JV, an Ares-led investor group purchased approximately 2.3 million shares of our common stock in a private placement for an aggregate purchase price of $50 million.

NOTE 15 CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Our Credit Facilities and Second Lien Notes are guaranteed both fully and unconditionally and jointly and severally by our material wholly owned subsidiaries (Guarantor Subsidiaries). Certain of our subsidiaries are not required to guarantee our Credit Facilities and Second Lien Notes (Non-Guarantor Subsidiaries) either because they hold assets that are less than 1% of our total consolidated assets or because they are not deemed a “subsidiary” under the applicable financing agreement. The following condensed consolidating balance sheets at December 31, 2017 and 2016, condensed consolidating statements of operations and statements of cash flows for the years ended December 31, 2017, 2016 and 2015 reflect the condensed consolidating financial information of our parent company, CRC (Parent), our combined Guarantor Subsidiaries, our combined Non-Guarantor Subsidiaries and the consolidation and elimination entries necessary to arrive at the information for CRC on a consolidated basis.

The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantor Subsidiaries operated as independent entities.

Condensed Consolidating Balance Sheets

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(in millions)		
As of December 31, 2017					
Total current assets	$ 13	$ 464	$ 12	$ (6)	$ 483
Total property, plant and equipment, net	24	5,580	92	—	5,696
Investments in consolidated subsidiaries	5,105	606	—	(5,711)	—
Other assets	—	27	1	—	28
TOTAL ASSETS	$ 5,142	$ 6,677	$ 105	$ (5,717)	$ 6,207
Total current liabilities	122	613	3	(6)	732
Long-term debt - principal amount	5,306	—	—	—	5,306
Deferred gain and issuance costs, net	287	—	—	—	287
Other long-term liabilities	154	445	3	—	602
Amounts due to (from) affiliates	87	(87)	—	—	—
Total equity	(814)	5,706	99	(5,711)	(720)
TOTAL LIABILITIES AND EQUITY	$ 5,142	$ 6,677	$ 105	$ (5,717)	$ 6,207
As of December 31, 2016					
Total current assets	$ 7	$ 418	$ —	$ —	$ 425
Total property, plant and equipment, net	25	5,856	4	—	5,885
Investments in consolidated subsidiaries	5,713	537	—	(6,250)	—
Other assets	—	44	—	—	44
TOTAL ASSETS	$ 5,745	$ 6,855	$ 4	$ (6,250)	$ 6,354
Total current liabilities	221	505	—	—	726
Long-term debt - principal amount	5,168	—	—	—	5,168
Deferred gain and issuance costs, net	397	—	—	—	397
Other long-term liabilities	132	487	1	—	620
Amounts due to (from) affiliates	384	(384)	—	—	—
Total equity	(557)	6,247	3	(6,250)	(557)
TOTAL LIABILITIES AND EQUITY	$ 5,745	$ 6,855	$ 4	$ (6,250)	$ 6,354

Condensed Consolidating Statements of Operations

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(in millions)		
For the year ended December 31, 2017					
Total revenues and other	$ 42	$ 1,947	$ 17	$ —	$ 2,006
Total costs and other	230	1,700	13	—	1,943
Non-operating (loss) income	(349)	24	—	—	(325)
Income tax benefit	—	—	—	—	—
NET (LOSS) INCOME	(537)	271	4	—	(262)
Net income attributable to noncontrolling interest	—	—	(4)	—	(4)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	$ (537)	$ 271	$ —	$ —	$ (266)
For the year ended December 31, 2016					
Total revenues and other	$ —	$ 1,543	$ 4	$ —	$ 1,547
Total costs and other	205	1,644	4	—	1,853
Non-operating income	475	32	—	—	507
Income tax benefit	78	—	—	—	78
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	$ 348	$ (69)	$ —	$ —	$ 279
For the year ended December 31, 2015					
Total revenues and other	$ —	$ 2,400	$ 3	$ —	$ 2,403
Total costs and other	302	7,236	7	—	7,545
Non-operating (loss) income	(343)	9	—	—	(334)
Income tax benefit	1,922	—	—	—	1,922
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	$ 1,277	$ (4,827)	$ (4)	$ —	$ (3,554)

Condensed Consolidating Statements of Cash Flows

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(in millions)		
For the year ended December 31, 2017					
Net cash (used) provided by operating activities	$ (481)	$ 718	$ 11	$ —	$ 248
Net cash used in investing activities	(4)	(212)	(97)	—	(313)
Net cash provided (used) by financing activities	492	(510)	91	—	73
Increase (decrease) in cash and cash equivalents	7	(4)	5	—	8
Cash and cash equivalents—beginning of period	—	12	—	—	12
Cash and cash equivalents—end of period	$ 7	$ 8	$ 5	$ —	$ 20
For the year ended December 31, 2016					
Net cash (used) provided by operating activities	$ (598)	$ 727	$ 1	$ —	$ 130
Net cash used in investing activities	(1)	(60)	—	—	(61)
Net cash provided (used) by financing activities	599	(667)	(1)	—	(69)
Increase in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents—beginning of period	—	12	—	—	12
Cash and cash equivalents— end of period	$ —	$ 12	$ —	$ —	$ 12
For the year ended December 31, 2015					
Net cash (used) provided by operating activities	$ (1,676)	$ 2,086	$ (7)	$ —	$ 403
Net cash used in investing activities	(24)	(733)	—	—	(757)
Net cash provided (used) by financing activities	1,700	(1,355)	7	—	352
Decrease in cash and cash equivalents	—	(2)	—	—	(2)
Cash and cash equivalents—beginning of period	—	14	—	—	14
Cash and cash equivalents—end of period	$ —	$ 12	$ —	$ —	$ 12

Quarterly Financial Data (Unaudited)

Quarter	2017 First	2017 Second	2017 Third	2017 Fourth	2016 First	2016 Second	2016 Third	2016 Fourth
	(in millions, except per share amounts)							
Revenues[a]	$ 590	$ 516	$ 445	$ 455	$ 322	$ 317	$ 456	$ 452
Operating income (loss)	$ 111	$ 39	$ (47)	$ (40)	$ (143)	$ (141)	$ (19)	$ (3)
Net income (loss) attributable to common stock[b]	$ 53	$ (48)	$ (133)	$ (138)	$ (50)	$ (140)	$ 546	$ (77)
Earnings (loss) per share attributable to common stock:								
Basic	$ 1.23	$ (1.13)	$ (3.11)	$ 3.23	$ (1.30)	$ (3.51)	$ 13.04	$ (1.83)
Diluted	$ 1.22	$ (1.13)	$ (3.11)	$ 3.23	$ (1.30)	$ (3.51)	$ 13.04	$ (1.83)

(a) Revenues include net derivative gains (losses).
(b) Net income (loss) attributable to common stock included the following unusual, out-of-period and infrequent items:

	2017 First	2017 Second	2017 Third	2017 Fourth	2016 First	2016 Second	2016 Third	2016 Fourth
	(in millions)							
Non-cash derivative (gains) losses, excluding noncontrolling interest	$(75)	$(35)	$72	$116	$ 81	$137	$ 25	$ 40
Early retirement, severance and other costs	$ 3	$ —	$ 1	$ 1	$ 14	$ 4	$ 1	$ 1
Net gains on early extinguishment of debt	$ (4)	$ —	$—	$ —	$(89)	$ (44)	$(660)	$(12)
Gains on asset divestitures	$(21)	$ —	$—	$ —	$ —	$ (31)	$ —	$ 1
Other	$ 1	$ 5	$ 8	$ 7	$ 7	$ 2	$ 5	$(27)
Deferred debt issuance costs write-off	$ —	$ —	$—	$ —	$ —	$ —	$ 12	$ —
Reversal of valuation allowance for deferred tax assets	$ —	$ —	$—	$ —	$ 63	$ —	$ —	$ —

Supplemental Oil and Gas Information (Unaudited)

The following table sets forth our net operating and non-operating interests in quantities of proved developed and undeveloped reserves of oil (including condensate), natural gas liquids (NGLs) and natural gas and changes in such quantities. Estimated reserves include our economic interests under arrangements similar to production-sharing contracts (PSCs) relating to the Wilmington field in Long Beach. All of our proved reserves are located within the state of California. See *Item 2—Properties—Our Reserves* for a discussion of the changes in proved reserves.

PROVED DEVELOPED AND UNDEVELOPED RESERVES

	Oil (MMBbl)[(a)]	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBoe)[(b)]
Balance at December 31, 2014	551	85	790	768
Revisions of previous estimates	(80)	(23)	(33)	(108)
Improved recovery	3	—	—	3
Extensions and discoveries	25	2	34	33
Purchases	4	1	8	6
Sales	—	—	—	—
Production	(37)	(6)	(84)	(58)
Balance at December 31, 2015	466	59	715	644
Revisions of previous estimates	(40)	—	(42)	(47)
Improved recovery	3	—	—	3
Extensions and discoveries	14	2	25	20
Purchases	—	—	—	—
Sales	(1)	—	—	(1)
Production	(33)	(6)	(72)	(51)
Balance at December 31, 2016	409	55	626	568
Revisions of previous estimates	47	7	104	71
Improved recovery	—	—	—	—
Extensions and discoveries	24	2	45	34
Purchases	—	—	—	—
Sales	(8)	—	(3)	(8)
Production	(30)	(6)	(66)	(47)
Balance at December 31, 2017	442	58	706	618
PROVED DEVELOPED RESERVES				
December 31, 2014	387	64	607	552
December 31, 2015	338	47	575	481
December 31, 2016	279	44	500	406
December 31, 2017[(c)]	304	45	543	440
PROVED UNDEVELOPED RESERVES				
December 31, 2014	164	21	183	216
December 31, 2015	128	12	140	163
December 31, 2016	130	11	126	162
December 31, 2017	138	13	163	178

(a) Includes proved reserves related to economic arrangements similar to PSCs of 108 MMBbl, 85 MMBbl, 103 MMBbl and 116 MMBbl at December 31, 2017, 2016, 2015 and 2014, respectively.

(b) 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.

(c) Approximately 21% of proved developed oil reserves, 9% of proved developed NGLs reserves, 15% of proved developed natural gas reserves and, overall, 19% of total proved developed reserves are non-producing. A majority of our non-producing reserves relate to steamfloods and waterfloods where full peak production response has not yet occurred due to the nature of such projects.

CAPITALIZED COSTS

Capitalized costs relating to oil and gas producing activities and related accumulated depreciation, depletion and amortization (DD&A) were as follows:

	As of December 31,	
	2017	2016
	(in millions)	
Proved properties	$ 19,664	$ 19,325
Unproved properties	1,111	1,111
Total capitalized costs[a]	20,775	20,436
Accumulated depreciation, depletion and amortization[b]	(15,391)	(14,891)
Net capitalized costs	$ 5,384	$ 5,545

(a) Includes acquisition costs, development costs and asset retirement obligations.
(b) Includes accumulated valuation allowance for total unproved properties of $819 million at December 31, 2017, 2016 and 2015.

COSTS INCURRED

Costs incurred relating to oil and gas activities include capital investments, exploration (whether expensed or capitalized), acquisitions and asset retirement obligations but exclude corporate items. The following table summarizes our costs incurred:

	For the years ended December 31,		
	2017	2016	2015
		(in millions)	
Property acquisition costs			
Proved properties	$ —	$ —	$ 77
Unproved properties	—	—	65
Exploration costs	25	21	43
Development costs[a]	357	102	290
Costs incurred	$ 382	$ 123	$ 475

(a) Total development costs include a $5 million decrease, a $49 million increase and a $62 million decrease in asset retirement obligations in 2017, 2016 and 2015, respectively.

RESULTS OF OPERATIONS

Our oil and gas producing activities, which exclude items such as asset dispositions and corporate overhead, were as follows:

	For the years ended December 31,					
	2017		2016		2015	
	(millions)	($/Boe)[a]	(millions)	($/Boe)[a]	(millions)	($/Boe)[a]
Revenues[b]	$ 1,931	$ 41.09	$ 1,700	$ 33.17	$ 2,222	$ 38.07
Production costs[c]	876	18.64	800	15.61	951	16.30
Adjusted general and administrative expenses[d]	34	0.72	37	0.72	58	1.00
Adjusted other operating expenses[e]	26	0.56	34	0.67	21	0.36
Depreciation, depletion and amortization	510	10.85	527	10.28	976	16.72
Taxes other than on income	110	2.34	121	2.36	156	2.67
Asset impairments[f]	—	—	—	—	4,852	83.14
Exploration expenses	22	0.47	23	0.45	36	0.62
Pretax income (loss)	353	7.51	158	3.08	(4,828)	(82.74)
Income tax (expense) benefit[g]	(115)	(2.45)	(64)	(1.25)	1,968	33.72
Results of operations	$ 238	$ 5.06	$ 94	$ 1.83	$ (2,860)	$ (49.02)

(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.

(b) Revenues are net of royalty payments.

(c) Production costs are the costs incurred in lifting the oil and natural gas to the surface and include gathering, processing, field storage and insurance on proved properties. Production costs on a per Boe basis, excluding the effects of PSC contracts, were $17.48, $14.69 and $15.58 for 2017, 2016 and 2015, respectively.

(d) Amounts exclude unusual and infrequent charges related to severance and early retirement costs associated with field personnel totaling $5 million ($0.10 per Boe), $6 million ($0.12 per Boe) and $18 million ($0.31 per Boe) for 2017, 2016 and 2015, respectively.

(e) For 2017, the amount excludes net unusual and infrequent charges of $5 million ($0.10 per Boe) primarily related to rig termination expenses partially offset by property tax refunds, recovery of amounts due from joint interest partners and other items. For 2016, the amount excludes net unusual and infrequent gains of $18 million ($0.35 per Boe) that include refunds partially offset by plant turnaround charges and other items. For 2015, the amount excludes charges related to the write-down of certain assets and rig termination charges of $82 million ($1.42 per Boe).

(f) At year-end 2015, we recorded pre-tax asset impairment charges of $4.9 billion on certain proved and unproved properties in the San Joaquin, Los Angeles, Ventura and Sacramento basins

(g) Income taxes are calculated on the basis of a stand-alone tax filing entity. The 2017 amount reflects the benefit of tax credits.

STANDARDIZED MEASURE, INCLUDING YEAR-TO-YEAR CHANGES THEREIN, OF DISCOUNTED FUTURE NET CASH FLOWS

For purposes of the following disclosures, discounted future net cash flows were computed by applying to our proved oil and gas reserves the unweighted arithmetic average of the first-day-of-the-month price for each month within the years ended December 31, 2017, 2016 and 2015, respectively. The realized prices used to calculate future cash flows vary by producing area and market conditions. Future operating and capital costs were determined using the current cost environment applied to expectations of future operating and development activities. Future income tax expense was computed by applying, generally, year-end statutory tax rates (adjusted for permanent differences and tax credits) to the estimated net future pre-tax cash flows, after allowing for the deductions for intangible drilling costs and tax DD&A. The cash flows were discounted using a 10% discount factor. The calculations assumed the continuation of existing economic, operating and contractual conditions at December 31, 2017, 2016 and 2015. Such assumptions, which are prescribed by regulation, have not always proven accurate in the past. Other valid assumptions would give rise to substantially different results.

Standardized Measure of Discounted Future Net Cash Flows

	At December 31,		
	2017	2016	2015
		(in millions)	
Future cash inflows	$ 26,685	$ 18,831	$ 26,477
Future costs			
Production costs[(a)]	(13,988)	(10,092)	(13,458)
Development costs[(b)]	(3,848)	(3,376)	(3,502)
Future income tax expense	(1,585)	(340)	(1,858)
Future net cash flows	7,264	5,023	7,659
Ten percent discount factor	(3,499)	(2,356)	(3,635)
Standardized measure of discounted future net cash flows	$ 3,765	$ 2,667	$ 4,024

(a) Includes general and administrative expenses and taxes other than on income.
(b) Includes asset retirement costs.

Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves Quantities

	For the years ended December 31,		
	2017	2016	2015
		(in millions)	
Beginning of year	$ 2,667	$ 4,024	$ 10,828
Sales of oil and natural gas, net of production and other operating costs	(918)	(742)	(1,038)
Changes in price, net of production and other operating costs	1,405	(2,297)	(12,362)
Previously estimated development costs incurred	159	62	394
Change in estimated future development costs	(98)	89	792
Extensions, discoveries and improved recovery, net of costs	177	117	292
Revisions of previous quantity estimates[a]	737	(247)	(872)
Accretion of discount	260	458	1,474
Net change in income taxes	(599)	854	4,228
Purchases and sales of reserves in place	(43)	(4)	45
Changes in production rates and other	18	353	243
Net change	1,098	(1,357)	(6,804)
End of year	$ 3,765	$ 2,667	$ 4,024

(a) Includes revisions related to performance and price changes.

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS

(in millions)	Balance at Beginning of Period	Charged (Credited) to Costs and Expenses	Charged to Other Accounts	Deductions[a]	Balance at End of Period
2017					
Deferred tax valuation allowance	$ 780	$ (78)	$ 4	$ —	$ 706
Other asset valuation allowance	$ 56	$ (12)	$ —	$ —	$ 44
Environmental reserves	$ 6	$ 4	$ —	$ (4)	$ 6
2016					
Deferred tax valuation allowance	$ 382	$ 398	$ —	$ —	$ 780
Other asset valuation allowance	$ 68	$ (12)	$ —	$ —	$ 56
Environmental reserves	$ 7	$ —	$ —	$ (1)	$ 6
2015					
Deferred tax valuation allowance[b]	$ —	$ 294	$ 88	$ —	$ 382
Other asset valuation allowance	$ 10	$ 58	$ —	$ —	$ 68
Environmental reserves	$ 8	$ —	$ —	$ (1)	$ 7

(a) Consists of payments.

(b) Our 2015 deferred tax liabilities were net of $88 million, which represented the federal benefit for the state-related portion of the deferred tax valuation allowance.

ITEM 9 CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A CONTROLS AND PROCEDURES

Management's Annual Assessment of and Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

We have assessed the effectiveness of our internal control system as of December 31, 2017 based on the criteria for effective internal control over financial reporting described in Internal Control—Integrated Framework issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, we believe that, as of December 31, 2017, our system of internal control over financial reporting is effective.

Our independent auditors, KPMG LLP, have issued a report on our internal control over financial reporting, which is set forth in *Item 8—Financial Statements and Supplementary Data*.

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer (CEO) and chief financial officer (CFO), has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d- 15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act)), as of the end of the period covered by this Annual Report on Form 10-K. Based on that evaluation, our CEO and CFO have concluded that, as of December 31, 2017, our disclosure controls and procedures are effective and are designed to provide reasonable assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission (SEC), and that such information is accumulated and communicated to our management, including our CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during our fourth fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Limitations on Effectiveness of Controls and Procedures

In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

ITEM 9B OTHER INFORMATION

None.

PART III

ITEM 10 DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated by reference to our Proxy Statement for the 2018 Annual Meeting of Stockholders to be filed with the Securities and Exchange Commission (SEC) within 120 days of the fiscal year ended December 31, 2017 (Proxy Statement) where it will appear in the (i) *Corporate Governance* section under *General Overview* and *Our Board of Directors*, (ii) *Board Leadership Structure and Committees—Committees of the Board,* (iii) *Stock Ownership Information—Section 16(a) Beneficial Ownership Reporting Compliance* and (iv) *Stockholder Proposals and Other Company Information* section under *Stockholder Proposals and Director Nominations*. See *Part I—Executive Officers* of this report for the list of our executive officers and related information.

Our board of directors has adopted a code of business conduct applicable to all officers, directors and employees, which is available on our website (www.crc.com). We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding amendment to, or waiver from, a provision of our code of business conduct by posting such information on our website at the address specified above.

ITEM 11 EXECUTIVE COMPENSATION

The information required by this item is incorporated by reference to our Proxy Statement where it appears in the *Compensation Discussion and Analysis* and *Compensation Committee Interlocks and Insider Participation* sections. Pursuant to the rules and regulations under the Exchange Act, the information in the *Compensation Discussion and Analysis—Compensation Committee Report* section shall not be deemed to be "soliciting material," or to be "filed" with the SEC, or subject to Regulation 14A or 14C under the Exchange Act or to the liabilities under Section 18 of the Exchange Act, nor shall it be deemed incorporated by reference into any filing under the Securities Act of 1933.

ITEM 12 SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item is incorporated by reference to our Proxy Statement where it appears under the *Stock Ownership Information—Security Ownership of Directors, Management and Certain Beneficial Holders* section. See also *Item 5—Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities—Securities Authorized for Issuance Under Equity Compensation Plans*.

ITEM 13 CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated by reference to our Proxy Statement where it appears in the *Certain Relationships and Related Transactions* section (except under the subheading *Policies and Procedures*) and *Director Independence Determinations* section.

ITEM 14 PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated by reference to our Proxy Statement where it appears in the *Proposals Requiring Your Vote—Proposal 2: Ratification of the Appointment of the Independent Registered Public Accounting Firm* section.

PART IV

ITEM 15 EXHIBITS

The agreements included as exhibits to this report are included to provide information about their terms and not to provide any other factual or disclosure information about us or the other parties to the agreements. The agreements contain representations and warranties by each of the parties to the applicable agreement that were made solely for the benefit of the other agreement parties and:

- should not be treated as categorical statements of fact, but rather as a way of allocating the risk among the parties if those statements prove to be inaccurate;
- have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
- may apply standards of materiality in a way that is different from the way investors may view materiality; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

(a) (1) and (2). Financial Statements

Reference is made to Item 8 of the Table of Contents of this report where these documents are listed.

(a) (3). Exhibits

Exhibit Number	Exhibit Description
2.1	Separation and Distribution Agreement, dated as of November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 2.1 to Registrant’s Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
3.1	Amended and Restated Certificate of Incorporation of California Resources Corporation (filed as Exhibit 3.1 to Registrant’s Current Report on Form 8-K filed June 3, 2016 and incorporated herein by reference).
3.2	Amended and Restated Bylaws of California Resources Corporation (filed as Exhibit 3.2 to the Registrant’s Current Report on Form 8-K filed November 10, 2015 and incorporated herein by reference).
4.1	Indenture, dated October 1, 2014, by and among California Resources Corporation, the Guarantors and Wells Fargo Bank, National Association (filed as Exhibit 4.2 to Amendment No. 4 to the Registrant’s Information Statement on Form 10 filed October 8, 2014 and incorporated herein by reference).
4.2	Indenture, dated December 15, 2015, by and among California Resources Corporation, the Guarantors and the Bank of New York Mellon Trust Company, N.A. (filed as Exhibit 4.1 to Registrant’s Current Report on Form 8-K filed December 18, 2015 and incorporated herein by reference).

Exhibit Number	Exhibit Description
4.3	Guarantor Supplemental Indenture dated as of March 5, 2015, among California Resources Corporation, certain guarantors named therein and Wells Fargo Bank, National Association (filed as Exhibit 4.2 to Registrant's Registration Statement on Form S-4 filed March 12, 2015 and incorporated herein by reference).
4.4	Guarantor Supplemental Indenture dated as of March 4, 2016, among California Resources Corporation, certain guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.1 to Registrant's Quarterly Report on Form 10-Q filed August 4, 2016 and incorporated herein by reference).
4.5	Guarantor Supplement Indenture dated as of March 4, 2016, among California Resources Corporation, certain guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.2 to Registrant's Quarterly Report on Form 10-Q filed August 4, 2016 and incorporated herein by reference).
4.6	Guarantor Supplemental Indenture No. 2, dated as of April 29, 2016, among California Resources Corporation, certain guarantors named therein and Wilmington Trust, National Association, as trustee (filed as Exhibit 10.4 to Registrant's Quarterly Report on Form 10-Q filed August 4, 2016 and incorporated herein by reference).
4.7	Assumption Agreement dated as of March 6, 2015, among CRC Construction Services, LLC and JP Morgan Chase Bank, N.A., as Administrative Agent for lenders (filed as Exhibit 10.31 to Registrant's Registration Statement on Form S-4 filed March 12, 2015 and incorporated herein by reference).
4.8	Registration Rights Agreement, dated October 1, 2014, by and among California Resources Corporation, the Guarantors and the Initial Purchasers (filed as Exhibit 4.3 to Amendment No. 4 to the Registrant's Information Statement on Form 10 filed October 8, 2014 and incorporated herein by reference).
4.9	Form of 5% Senior Note due 2020 (included in Exhibit 4.2 to Amendment No. 4 to the Registrant's Information Statement on Form 10 filed October 8, 2014 and incorporated herein by reference).
4.10	Form of 5½% Senior Note due 2021 (included in Exhibit 4.2 to Amendment No. 4 to the Registrant's Information Statement on Form 10 filed October 8, 2014 and incorporated herein by reference).
4.11	Form of 6% Senior Note due 2024 (included in Exhibit 4.2 to Amendment No. 4 to the Registrant's Information Statement on Form 10 filed October 8, 2014 and incorporated herein by reference).
4.12	Form of 8% Senior Secured Second Lien Note due 2022 (included in Exhibit 4.1 to Registrant's Current Report on Form 8-K filed December 18, 2015 and incorporated herein by reference).
10.1	Credit Agreement, dated as of September 24, 2014, among California Resources Corporation, the Lenders and JPMorgan Chase Bank, N.A. as Administrative Agent, a Swingline Lender and a Letter of Credit Issuer and Bank of America, N.A. as Syndication Agent, a Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 10.25 to Amendment No. 5 to the Company's Registration Statement on Form 10 filed October 14, 2014, and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.2	First Amendment to Credit Agreement, dated as of February 25, 2015, among California Resources Corporation, the Lenders and JPMorgan Chase Bank, N.A. as Administrative Agent, a Swingline Lender and a Letter of Credit Issuer and Bank of America, N.A. as Syndication Agent, a Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 10.35 to the Registrant's Annual Report on Form 10-K filed February 27, 2015, and incorporated herein by reference).
10.3	Second Amendment to Credit Agreement, dated November 2, 2015, among California Resources Corporation, the Lenders and JPMorgan Chase Bank, N.A. as Administrative Agent, a Swingline Lender and a Letter of Credit Issuer and Bank of America, N.A. as Syndication Agent, a Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed November 6, 2015, and incorporated herein by reference).
10.4	Third Amendment to Credit Agreement, dated February 23, 2016, among California Resources Corporation and JP Morgan Chase Bank, N.A., as Administrative Agent, a Swingline Lender and a Letter of Credit Issuer and Bank of America, N.A. as Syndication Agent, a Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 99.1 to the Registrant's Current Report on Form 8-K filed February 23, 2016, and incorporated herein by reference).
10.5	Fourth Amendment to Credit Agreement dated as of April 22, 2016, among California Resources Corporation, as the Borrower and JP Morgan Chase Bank, N.A., as Administrative Agent, a Swingline Lender and a Letter of Credit Issuer and Bank of America, N.A., as Syndication Agent, Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 99.1 to the Registrant's Current Report on Form 8-K filed April 22, 2016, and incorporated herein by reference).
10.6	Fifth Amendment and Waiver to Credit Agreement, dated August 12, 2016, among California Resources Corporation, as the Borrower and JP Morgan Chase Bank, N.A., as Administrative Agent, a Swingline Lender and a Letter of Credit Issuer and Bank of America, N.A., as Syndication Agent, a Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 10.2 to the Registration's Current Report on Form 8-K filed August 17, 2016 and incorporated herein by reference).
10.7	Sixth Amendment to Credit Agreement, dated as of February 14, 2017, among California Resources Corporation, as the Borrower, JP Morgan Chase Bank, N.A., as Administrative Agent, Swingline Lender and a Letter of Credit Issuer, Bank of America, N.A., as Syndication Agent, Swingline Lender and a letter of Credit Issuer, and the Lenders (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed February 16, 2017, and incorporated herein by reference).
10.8	Seventh Amendment to Credit Agreement, dated as of November 9, 2017, among California Resources Corporation, as the Borrower, JP Morgan Chase Bank, N.A., as Administrative Agent, Swingline Lender and a Letter of Credit Issuer, Bank of America, N.A., as Syndication Agent, Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed November 13, 2017, and incorporated herein by reference).
10.9	Credit Agreement, dated August 12, 2016, among California Resources Corporation, as the Borrower, the several Lenders from time to time parties thereto, Goldman Sachs Bank USA, as Lead Arranger and Bookrunner, and The Bank of New York Mellon Trust Company, N.A., as Administrative Agent and Collateral Agent (filed as Exhibit 10.1 to the Registration's Current Report on Form 8-K filed August 17, 2016 and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.10	Credit Agreement, dated as of November 17, 2017, by and among the Company, as the Borrower, Bank of New York Mellon Trust, N.A., as Administrative Agent, and the various Lenders identified therein (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed November 17, 2017, and incorporated herein by reference).
10.11	Omnibus Amendment, dated September 12 2016, among California Resources Corporation, the Guarantors party thereto, the Collateral Trustee and the other party lien representatives party thereto (filed as Exhibit 10.3 to the Registration's Quarterly Report on Form 10-Q filed November 3, 2016 and incorporated herein by reference).
10.12	Transition Services Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.4 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.13	Tax Sharing Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.2 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.14	Employee Matters Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.3 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.15	Intellectual Property License Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.7 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.16	Area of Mutual Interest Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.5 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.17	Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, dated November 5, 1991, by and among the State of California, by and through the State Lands Commission, the City of Long Beach, Atlantic Richfield Company and ARCO Long Beach, Inc. (filed as Exhibit 10.10 to Amendment No. 2 to the Company's Registration Statement on Form 10 filed August 20, 2014, and incorporated herein by reference).
10.18	Amendment to the Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, dated January 16, 2009, by and among the State of California, by and through the State Lands Commission, the City of Long Beach, and Oxy Long Beach, Inc. (filed as Exhibit 10.11 to Amendment No. 2 to the Company's Registration Statement on Form 10 filed August 20, 2014, and incorporated herein by reference).
10.19	Contractors' Agreement, by and between the City of Long Beach, Humble Oil & Refining Company, Shell Oil Company, Socony Mobil Oil Company, Inc., Texaco, Inc., Union Oil Company of California, Pauley Petroleum, Inc., Allied Chemical Corporation, Richfield Oil Corporation and Standard Oil Company of California (filed as Exhibit 10.12 to Amendment No. 2 to the Company's Registration Statement on Form 10 filed August 20, 2014, and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.20	Confidentiality and Trade Secret Protection Agreement, dated November 25, 2014, by and between Occidental Petroleum Corporation and California Resources Corporation, dated November 24, 2014 (filed as Exhibit 10.6 to the Company's Current Report on Form 8-K filed on December 1, 2014, and incorporated herein by reference).
10.21	Second Amended and Restated Limited Liability Company Agreement of Elk Hills Power, LLC, dated as of February 7, 2018, by and among Elk Hills Power, LLC, California Resources Elk Hills, LLC and ECR Corporate Holdings L.P. (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on February 7, 2018, and incorporated herein by reference).
10.22	Commercial Agreement, dated as of February 7, 2018, by and between Elk Hills Power, LLC and California Resources Elk Hills, LLC (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on February 7, 2018, and incorporated herein by reference).
10.23	Master Services Agreement, dated as of February 7, 2018, by and between Elk Hills Power, LLC and California Resources Elk Hills, LLC (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K filed on February 7, 2018, and incorporated herein by reference).
10.24	Form of Stock Purchase Agreement, dated as of February 7, 2018 (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K filed on February 7, 2018, and incorporated herein by reference).
10.25	Registration Rights Agreement, dated as of February 7, 2018, by and between California Resources Corporation and the purchasers named therein (filed as Exhibit 10.5 to the Company's Current Report on Form 8-K filed on February 7, 2018, and incorporated herein by reference).
	The following are management contracts and compensatory plans required to be identified specifically as responsive to Item 601(b)(10)(iii)(A) of Regulation S-K pursuant to Item 15(b) of Form 10-K.
10.26	California Resources Corporation Long-Term Incentive Plan Restricted Stock Unit Award Terms and Conditions (filed as Exhibit 10.3 to the Registrant's Quarterly Report Form 10-Q filed November 6, 2015, and incorporated herein by reference).
10.27	California Resources Corporation Long-Term Incentive Plan, 2016 Annual Incentive Award Summary (filed as Exhibit 10.5 on Registrant's Quarterly Report on Form 10-Q filed August 4, 2016 and incorporated herein by reference).
10.28	California Resources Corporation Long-Term Incentive Plan Performance Stock Unit Award Terms and Conditions (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q filed November 6, 2015, and incorporated herein by reference).
10.29	California Resources Corporation Long-Term Incentive Plan Nonstatutory Stock Option Award Terms and Conditions (filed as Exhibit 10.4 to the Registrant's Quarterly Report Form 10-Q filed November 6, 2015, and incorporated herein by reference).
10.30	California Resources Corporation Supplemental Savings Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on December 2, 2014, and incorporated herein by reference).
10.31	First Amendment to California Resources Corporation Supplemental Savings Plan (filed as Exhibit 10.18 to the Registrant's Annual Report on Form 10-K filed February 29, 2016, and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.32	California Resources Corporation Supplemental Retirement Plan II (filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on December 2, 2014, and incorporated herein by reference).
10.33	California Resources Corporation Deferred Compensation Plan (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on December 2, 2014, and incorporated herein by reference).
10.34	California Resources Corporation Long-Term Incentive Plan (filed as Exhibit 4.3 to the Registrant's related Registration Statement on Form S-8 filed November 26, 2014 and incorporated herein by reference).
10.35	Acknowledgment of Amendment to Long-Term Incentive Award Terms with William E. Albrecht (filed as Exhibit 10.22 to the Registrant's Annual Report on Form 10-K filed February 29, 2016, and incorporated herein by reference).
10.36	Form of Nonstatutory Stock Option Award Terms and Conditions (filed as Exhibit 10.6 to Amendment No. 3 to the Registrant's Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.37	Form of Restricted Stock Unit Award Terms and Conditions (filed as Exhibit 10.6 to the Registrant's Quarterly Report on Form 10-Q filed August 4, 2016 and incorporated herein by reference).
10.38	Form of Nonstatutory Stock Option Award Terms and Conditions (filed as Exhibit 10.5 to the Registrant's Quarterly Report on Form 10-Q filed November 3, 2016, and incorporated herein by reference).
10.39	Form of Performance Incentive Award Terms and Conditions (filed as Exhibit 10.6 to the Registrant's Quarterly Report on Form 10-Q filed November 3, 2016, and incorporated herein by reference).
10.40	Form of Restricted Stock Incentive Award Terms and Conditions (Not Performance-Based) (filed as Exhibit 10.8 to Amendment No. 3 to the Registrant's Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.41	Form of Restricted Stock Incentive Award Terms and Conditions (Performance-Based) (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed February 10, 2015, and incorporated herein by reference).
10.42	Form of Restricted Stock Unit Award for Non-Employee Directors Grant Agreement (filed as Exhibit 10.9 to Amendment No. 3 to the Registrant's Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.43	Form of Long-Term Incentive Award Terms and Conditions (Cash-based, Equity, and Cash-settled Award) (filed as Exhibit 10.10 to Amendment No. 3 to the Registrant's Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.44	Form of Restricted Stock Incentive Award Terms and Conditions (Replacement Award-Performance-Based) (filed as Exhibit 10.11 to Amendment No. 3 to the Registrant's Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.45	Form of Restricted Stock Incentive Award Terms and Conditions (Replacement Award-Not Performance-Based) (filed as Exhibit 10.12 to Amendment No. 3 to the Registrant's Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.46	Form of Phantom Share Unit Award Terms and Conditions (Replacement Award) (filed as Exhibit 10.13 to Amendment No. 3 to the Registrant's Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.47	California Resources Corporation 2014 Employee Stock Purchase Plan (filed as Exhibit 4.3 to the Registrant's related Registration Statement on Form S-8 filed November 26, 2014 and incorporated herein by reference).
10.48	Form of Indemnification Agreements (filed as Exhibit 10.14 to Amendment No. 3 Registrant's Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.49	First Amendment to the California Resources Corporation 2014 Employee Stock Purchase Plan effective May 4, 2016 (filed as Annex C-1 to the Registrant's Definitive Proxy Statement on Schedule 14A filed March 23, 2016 and incorporated herein by reference).
12*	Computation of Ratio of Earnings to Fixed Charges.
21*	List of Subsidiaries of California Resources Corporation.
23.1*	Consent of Independent Registered Public Accounting Firm.
23.2*	Consent of Independent Petroleum Engineers.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Ryder Scott Company Estimated Future Reserves Attributable to Certain Leasehold and Royalty Interests as of December 31, 2017.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.

*—Filed herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CALIFORNIA RESOURCES CORPORATION

February 26, 2018

By: /s/ Todd A. Stevens

Todd A. Stevens
President
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

	Title	Date
/s/ Todd A. Stevens Todd A. Stevens	President, Chief Executive Officer and Director	February 26, 2018
/s/ Marshall D. Smith Marshall D. Smith	Senior Executive Vice President and Chief Financial Officer	February 26, 2018
/s/ Roy Pineci Roy Pineci	Executive Vice President—Finance and Principal Accounting Officer	February 26, 2018
/s/ William E. Albrecht William E. Albrecht	Chairman of the Board	February 26, 2018
/s/ Justin A. Gannon Justin A. Gannon	Director	February 26, 2018
/s/ Ronald L. Havner Ronald L. Havner	Director	February 26, 2018
/s/ Harold M. Korell Harold M. Korell	Director	February 26, 2018
/s/ Harry T. McMahon Harry T. McMahon	Director	February 26, 2018
/s/ Richard W. Moncrief Richard W. Moncrief	Director	February 26, 2018
/s/ Avedick B. Poladian Avedick B. Poladian	Director	February 26, 2018
/s/ Anita M. Powers Anita M. Powers	Director	February 26, 2018
/s/ Robert V. Sinnott Robert V. Sinnott	Director	February 26, 2018

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101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

Annual Meeting

California Resources Corporation's annual meeting of stockholders will be held at 11:00 a.m. on May 9, 2018 at the Bakersfield Marriott at the Convention Center located at 801 Truxtun Avenue, Bakersfield, California 93301.

Investor Relations Contact

Company financial information, public disclosures and other information are available through our website at www.crc.com. We will promptly deliver free of charge, upon request, an annual report on Form 10-K to any stockholder requesting a copy. Requests should be directed to our Investor Relations team at our corporate headquarters address or sent to ir@crc.com.

Auditors

KPMG LLP, Los Angeles, California

Transfer Agent & Registrar

American Stock Transfer and Trust Company, LLC

Shareholder Services

6201 15th Avenue, Brooklyn, New York 11219

(866) 659-2647

crc@amstock.com

www.amstock.com

Stock Exchange Listing

California Resources Corporation's common stock is listed on the New York Stock Exchange (NYSE). The symbol is CRC.

CRC LISTED NYSE

Officers

Todd A. Stevens
President,
Chief Executive Officer
and Director

Marshall D. Smith
Senior Executive Vice President
and Chief Financial Officer

Shawn M. Kerns
Executive Vice President,
Operations and Engineering

Francisco Leon
Executive Vice President,
Corporate Development and
Strategic Planning

Roy Pineci
Executive Vice President,
Finance

Michael L. Preston
Executive Vice President,
General Counsel and
Corporate Secretary

Charles F. Weiss
Executive Vice President,
Public Affairs

Darren Williams
Executive Vice President,
Operations and Geoscience

Board Of Directors

William E. Albrecht
Chairman of the Board, Former
Vice President, Occidental
Petroleum Corporation

Justin A. Gannon
Former Regional Managing
Partner, Grant Thornton LLP

Ronald L. Havner, Jr.
Chairman of the Board
and Chief Executive Officer,
Public Storage

Harold M. Korell
Lead Independent Director,
Former Chairman of the Board,
Southwestern Energy Company

Harry T. McMahon
Former Executive Vice
Chairman, Bank of America
Merrill Lynch

Richard W. Moncrief
Chairman of the Board and
Chief Executive Officer,
Moncrief Oil International

Avedick B. Poladian
Former Executive Vice
President and Chief Operating
Officer, Lowe Enterprises

Anita M. Powers
Former Executive Vice
President of Worldwide
Exploration, Occidental Oil
and Gas Corporation and
Vice President, Occidental
Petroleum Corporation

Robert V. Sinnott
Co-Chairman,
Kayne Anderson Capital

Todd A. Stevens
President, Chief Executive
Officer and Director, California
Resources Corporation

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