2015

CALIFORNIA RESOURCES CORPORATION ANNUAL REPORT

FINANCIAL AND OPERATING HIGHLIGHTS

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

Financial Highlights	**2015**	**2014**	**2013**
Revenues	$ 2,403	$ 4,173	$ 4,284
Income / (Loss) Before Income Taxes	$ (5,476)	$ (2,421)	$ 1,447
Net Income / (Loss)	$ (3,554)	$ (1,434)	$ 869
Adjusted Net Income / (Loss) [(a)]	$ (311)	$ 650	$ 869
EPS – Basic and Diluted [(b)]	$ (9.27)	$ (3.75)	$ 2.24
Adjusted EPS – Basic and Diluted [(b)]	$ (0.81)	$ 1.67	$ 2.24
Net Cash Provided by Operating Activities	$ 403	$ 2,371	$ 2,476
Capital Investments	$ (401)	$ (2,089)	$ (1,669)
Proceeds from Debt, Net	$ 379	$ 6,360	—
Cash Dividends to Occidental	—	$ (6,000)	—
Net Cash Provided (Used) by Financing Activities	$ 352	$ (45)	$ (763)
Total Assets	$ 7,053	$ 12,429	$ 14,297
Long-Term Debt – Principal Amount	$ 6,043	$ 6,360	—
Deferred Gain and Issuance Costs, Net	$ 491	$ (68)	—
Equity / Net Investment	$ (916)	$ 2,611	$ 9,989
Weighted Average Shares Outstanding	383.2	381.9	—
Year-End Shares	388.2	385.6	—

Operational Highlights	**2015**	**2014**	**2013**
Production:			
Crude Oil (MBbl/d)	104	99	90
NGLs (MBbl/d)	18	19	20
Natural Gas (MMcf/d)	229	246	260
Total (MBoe/d)	160	159	154
Average Realized Prices:			
Crude with hedge ($/Bbl)	$ 49.19	$ 92.30	$ 104.16
Crude without hedge ($/Bbl)	$ 47.15	$ 92.30	$ 104.16
NGLs ($/Bbl)	$ 19.62	$ 47.84	$ 50.43
Natural Gas with hedge ($/Mcf)	$ 2.66	$ 4.39	$ 3.73
Reserves:			
Crude Oil (MMBbl)	466	551	532
NGLs (MMBbl)	59	85	71
Natural Gas (Bcf)	715	790	844
Total (MBoe/d)	644	768	744
Acreage (in thousands):			
Net Developed	736	716	701
Net Undeveloped	1,653	1,691	1,604
Total	2,389	2,407	2,305
Closing Share Price	$ 2.33	$ 5.51	

(a) For discussion of, or reconciliation to the most closely-related GAAP measure, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Results," in our Form 10-K.

(b) On November 30, 2014, the spin-off date from Occidental Petroleum Corporation, 381.4 million shares of our common stock were distributed, of which approximately 18.5% was retained by Occidental. Additional shares were distributed in December to substitute for Occidental stock awards. For comparative purposes, and to provide a more meaningful calculation of weighted-average shares outstanding, we have assumed these amounts to be outstanding for each period prior to the spin-off. Adjusted EPS – Basic and Diluted for each year is Adjusted Net Income / (Loss) divided by weighted average shares outstanding for each respective year.

A MESSAGE TO OUR STOCKHOLDERS

Dear Stockholder,

California Resources Corporation accomplished a great deal in our first full year as a stand-alone company. We demonstrated the quality of our asset base, the commitment of our management team and operational excellence over the items that were under our control.

Despite the most severe commodity price downturn in nearly 30 years, our focus has not wavered. We remain committed as always to maximize shareholder returns by safely and responsibly developing conventional and unconventional assets exclusively in California while serving as responsible stewards and valued neighbors in the communities in which we operate.

We believe that the competitive advantages of our large underdeveloped resource base, in conjunction with our financial discipline, will reward investors over time. CRC's diverse and low-decline assets provide a stable base and flexibility to manage effectively through short term events while maintaining and enhancing long term value. Lastly, we believe our management team's extensive experience and knowledge of our assets has served stockholders well in this commodity price downturn.

In 2015, our priorities were to deleverage our balance sheet, protect our base production, and protect our profit margins amid falling prices. To pursue these goals we held fast to our key tenet of living within our means and focused our capital investments on CRC's highest value projects as determined by our VCI metric. Starting immediately at the Spin-off, we asked our entire workforce to serve and focus on our operations, which generated exceptional results, including growing our crude oil production by five percent in 2015 and replacing more than the reserves we produced at a low replacement cost, excluding the effects of price changes.

We made excellent progress in 2015 on all items under our control, and intend to extend our success in these items into 2016. Below we review our 2015 accomplishments in more detail, then highlight the competitive strengths that our assets provide along with our 2016 plan to weather the downturn.

Fiscal Discipline—Living within our Means

Our top priority remains reducing the debt we have carried since the Spin-off. A key tenet for CRC is to live within our cash flow. This has been a rare quality in our sector, but living by this principle has served us well. In 2015, we generated operating cash flow over $400 million, which covered our capital program, and, excluding residual fourth quarter 2014 capital, allowed us to be free cash flow positive for the year. We also executed a bond exchange in 2015 that reduced the outstanding principal on our bonds by about $560 million.

In late 2014, seeing the early phases of the commodity price drop, we swiftly made the decision to reduce our drilling activity and went from 27 drilling rigs to 3 rigs in January of 2015. Similarly, we reduced our capital program from $2.1 billion to a $440 million budget for 2015, an 80-percent reduction and deeper than all our industry peers. Our 2015 actual capital investment totaled $400 million, showing a 10-percent improvement over our plan. This improvement resulted from process efficiencies identified by our resourceful workforce and deflationary pressures within the industry generally. Even with lower-than-planned capital, we drilled more wells than were contemplated in our capital plan. We focused our capital investments on crude oil projects, mainly steamfloods and waterfloods, and grew our average daily oil production by five percent over 2014. We increased our overall production by one percent and achieved a 140-percent organic reserves replacement rate at a low replacement cost.

We suspended our dividend in 2015 due to the continuing downturn in the commodity prices. Both the Board of Directors and I feel that it is prudent to do so in the current commodity environment. We will review this decision when we feel that we can distribute a meaningful and sustainable dividend. This downturn calls for our management team to focus on near-term liquidity decisions and weigh our deleveraging opportunities while preserving CRC's evident long-term value.

Enhance our Margins

Our operation teams have been successful in reducing our operating costs and improving efficiencies across our operations in 2015. Overall, we were able to reduce our per barrel cash costs by 13 percent, excluding interest, in 2015. Production costs were reduced by 11 percent to $16.30 per barrel. These cost reductions are not attributable to any one item; rather, they reflect the hard work and ingenuity of our dedicated employee base that generated numerous ideas during 2015. We have begun 2016 with a similar focus on costs and expect to reduce our cash costs even further.

To protect our cash flow stream, margins and capital investment program, we launched a hedging program immediately after our spin-off. We instituted a program utilizing a combination of floors, swaps and costless collars. We currently have approximately 30 percent of our expected 2016 crude oil volumes protected at above $50 Brent on average. To provide a predictable cash flow stream, we will continue to add hedges opportunistically and attempt to protect approximately 50 percent of the value of our quarterly production as we move through the year.

Protect our Base

CRC owns and operates an exceptional portfolio of resources and we took great care in 2015 to protect the value of those assets for the long term. CRC is the largest independent producer in the state on a gross operated basis. California has five of the top 12 fields in the lower 48 states as ranked by total production. We operate in four of these fields and all four major basins in the state. Two of them, the Elk Hills and Wilmington fields, serve as our flagship operations.

Elk Hills serves as a classic example of the characteristics that make our asset base unique and compelling. It is a large field diversified across many different producing strata and production types. It is fully integrated with substantial midstream infrastructure, a 550-megawatt power plant and a state-of-the-art Central Control facility. The field was purchased from the U.S. government and has been in production for 100 years, yet we continue to find new opportunities. 2015 marked the first year in its history that Elk Hills did not have a single drilling rig operating—as a result we witnessed first-hand the field's modest production decline with no added drilling capital. Elk Hills' production response was impressive and exhibited a decline rate that was better than our expectations.

CRC's Wilmington field in the Los Angeles basin has a long history as well; the THUMS islands are part of the landscape in Long Beach, and celebrated their 50th anniversary in 2015. CRC has a unique production sharing contract that benefits the City of Long Beach, the State of California and CRC through continued field development. Since we started operating the field in 2000, our technical teams have continued to find new oil resources. As a result, we typically end each year with a larger inventory of drill locations than we started with, even after the drilling program is complete. We continue to see evidence that big fields really do get bigger.

Both of these fields, as well as many of our other steamfloods and waterfloods, contribute to the low-decline nature of our asset base. CRC's technical teams did an excellent job of maintaining our base production in 2015 despite the low capital investment. We believe our current corporate decline is a modest 10-15 percent, closer to the higher end during periods of low capital investment due to increased downtime. We believe this is a key source of differentiation from our peers in the industry. We believe that our future investments in steamflood and waterflood fields in our portfolio will help further moderate our base decline, underpinning our value proposition.

Building a deep inventory

Although our drilling and workover activity is being further reduced for 2016, we are continuing to build value for the future. Our ongoing geotechnical analysis has produced results on both the development and exploration fronts. As an example, in 2015 we had a team of geoscientists and engineers review a small field for opportunities and their work produced a 5-fold increase in reserves and economic drilling opportunities. This result is indicative of the under-developed nature of California's oil and gas resources. We are taking this same approach and applying it across our 137 fields in the state. We are refining and enhancing our life-of-field plans to capture the full potential of the approximately 40 billion barrels of original oil in place[1] across our 2.4 million net acres. California truly is a world-class hydrocarbon province, and the data supports that conclusion. Today's technology will allow CRC to better image, develop, and more efficiently extract value from our portfolio.

In our 2015 exploration program, we further delineated several prospects and continued to see success from a 2014 well. The well was in a structural play that was originally completed in the deepest reservoir interval in the field and delivered production of several hundred barrels of oil per day. During the year, we moved up to a second reservoir interval and saw flow rates in excess of 750 barrels of oil per day. This well was completed in a naturally flowing conventional reservoir that has further behind pipe potential. This example also illustrates the underexplored nature of California.

Our portfolio has over 125 independent oil and gas prospects, most of which have stacked pay potential and are directly analogous to either producing fields or some of CRC's key discoveries. We have also made discoveries within the California shale reservoirs that provide numerous drilling opportunities for long-term growth. We believe we hold one of the largest and most diverse sets of exploration opportunities in the lower 48 states.

Responsible Californians

We live and work in California and know the needs of our communities first hand. We strive to serve as responsible citizens who promote the economic well-being of the state in a responsible manner. Our Board, management team and employees share three core values—Character, Responsibility and Commitment—that define how we conduct business and interact with our stakeholders.

As you may have heard me say, there are ''hard rights'' and ''easy wrongs'' in decision making. We believe that we have made the hard right decisions that were needed to successfully meet the challenges of this period. We are following through with a commitment to protecting long-term value. We continue to focus our efforts on the deleveraging process and steering through this price downturn toward the value that lies ahead for our shareholders. We continue to receive the support of our 21-firm bank group in 2016 to weather this cyclical bottom on crude oil.

All Californians have seen the effects of the multi-year drought, and CRC has worked diligently with state and local agencies to aid California by increasing our water recycling efforts, reducing our fresh water usage and supplying surplus non-potable water for irrigation and groundwater recharge. We have made significant investments in each of these areas. In 2015, we recycled approximately 77 percent of our produced water to meet our operational needs. In addition, we supplied more than 2.6 billion gallons of treated reclaimed water for agricultural needs in 2015, setting a company record

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1 The United States Securities and Exchange Commission (SEC) guidelines strictly prohibit us from using the term ''original oil in place'' in our SEC filings. This term represents an estimate of the total volume of oil stored in a reservoir prior to production and is not intended to correspond to probable or possible reserves as defined by SEC regulations. By their nature these estimates are more speculative than proved, probable or possible reserves and subject to greater risk they will not be realized.

at the height of California's drought. We are working to increase this important water supply over the coming years.

Our commitment to California is to provide the state with a safe, secure and reliable supply of energy. California continues to import the majority of its energy needs, often from places that do not meet California's high standards of safety and environmental protection. In 2015, CRC supplied 58 million barrels of oil equivalent, which equates to 122 thousand barrels per day of crude oil and natural gas liquids and 229 million cubic feet per day of natural gas. We also supplied 462 gross megawatts of electricity per day through our power plant in Elk Hills, which is enough to power Anaheim for a year.

Character is shown best by the choices you make in trying times. Given the erosion in crude oil prices that weighed heavily on our entire industry, we at CRC also have had to make tough choices. These decisions should position CRC to emerge from this trough in a stronger position to build long-term value for our investors, employees, suppliers and communities in which we operate.

We recognize that working our way through this challenging period calls for everyone in the company to make appropriate sacrifices. Therefore, in accordance with our core values, CRC's executives have chosen to take a reduction in salary. Unfortunately, we also had to reduce our staffing levels to match the current low price environment.

We believe that the company's strong, diverse and low-decline asset base serves us well in our efforts to navigate through this period. We will continue to build inventory for when we can ramp up our activity level in a continued fiscally responsible manner that will provide long-term stockholder value. Our leadership team has been through commodity cycle ups and downs before. We fully expect the significant reduction in industry-wide capital investment in 2015 and continuing into 2016 will ultimately lead to a rebound in commodity prices and we will be prepared to capitalize.

Todd Stevens

Todd A. Stevens

President & CEO

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, 2015

☐ **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
5% Senior Notes due 2020	
5½% Senior Notes due 2021	
6% Senior Notes due 2024	

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, or a smaller reporting company. See the definitions of ''large accelerated filer,'' ''accelerated filer'' and ''smaller reporting company'' in Rule 12b-2 of the Exchange Act.

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

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 $2.3 billion, computed by reference to the closing price on the New York Stock Exchange composite tape of $6.04 per share of Common Stock on June 30, 2015. 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, 2016, there were 388,181,900 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 2016 Annual Meeting of Stockholders, are incorporated by reference into Part III of this Form 10-K.

LIST OF OPERATING SUBSIDIARIES

The following is a list of our subsidiaries at December 31, 2015 other than certain subsidiaries that did not in the aggregate constitute a significant subsidiary.

Name	Jurisdiction of Formation
California Heavy Oil, Inc.	Delaware
California Resources Coles Levee, LLC	Delaware
California Resources Coles Levee, L.P.	Delaware
California Resources Elk Hills, LLC	Delaware
California Resources Long Beach, Inc.	Delaware
California Resources Petroleum Corporation	Delaware
California Resources Production Corporation	Delaware
California Resources Tidelands, Inc.	Delaware
California Resources Wilmington, LLC	Delaware
CRC Construction Services, LLC	Delaware
CRC Marketing, Inc.	Delaware
CRC Services, LLC	Delaware
Elk Hills Power, LLC	Delaware
Socal Holding, LLC	Delaware
Southern San Joaquin Production, Inc.	Delaware
Thums Long Beach Company	Delaware
Tidelands Oil Production Company	Texas

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PART I

Item 1 BUSINESS

In this report, 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 assumed in connection with the spin-off from Occidental on November 30, 2014 (the Spin-off), and (3) all references to ''Occidental'' refer to Occidental Petroleum Corporation, our former parent, and its subsidiaries.

General

We are an independent oil and natural gas exploration and production company operating properties exclusively within the State of California. 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 the Spin-off. On November 30, 2014, Occidental distributed shares of our common stock on a pro rata basis to Occidental stockholders and we became an independent, publicly traded company, referred to in this annual report as the Spin-off. Occidental retained approximately 18.5% of our outstanding shares of common stock which it has stated it intends to divest on March 24, 2016.

Business Operations

Our business is focused on conventional and unconventional assets, exclusively in California. We are the largest oil and gas producer in California on a gross operated basis and we believe we have established the largest privately-held mineral acreage position in the state, consisting of approximately 2.4 million net acres spanning the state's four major oil and gas basins. We produced on average approximately 160 thousand barrels of oil equivalent per day (MBoe/d) net for the year ended December 31, 2015. As of December 31, 2015, we had net proved reserves of 644 million barrels of oil equivalent (MMBoe), with approximately 75% proved developed. Oil represented 72% of our proved reserves. Our aggregate PV-10 value was $5.1 billion. For an explanation of the non-GAAP financial measure PV-10 and a reconciliation of PV-10 to Standardized Measure, the most directly comparable GAAP financial measure, see ''Our Reserves and Production Information'' below.

Much of the global exploration and production industry is challenged at current price levels, putting pressure on the industry's ability to generate positive cash flow and access capital. In response to the sharp price declines that began in the second half of 2014, we significantly reduced our 2016 planned capital program to $50 million from $401 million in 2015 as described in additional detail below in ''Portfolio Management and 2016 Capital Budget.'' The curtailment of the development of our properties will lead to a decline in our production and possibly our reserves. Over the long term, a continued decline in our production and reserves would reduce our liquidity and ability to satisfy our debt obligations by negatively impacting our cash flow from operations and the value of our assets. In 2015, we emphasized projects and activities that focused on cash flow generation in the near term and met our investment criteria. We will continue to employ cost saving measures to more efficiently deploy our capital and to decrease our unit lease operating and general and administrative expenses. We are also pursuing a number of alternatives to deleverage our balance sheet and better align our capital structure with the current commodity price environment as described in more detail in ''Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operation—Liquidity and Financial Resources.''

Our asset base has the capacity in the aggregate to generate positive field-level cash flow in the current price environment for 2016. In addition, we believe our asset base has the potential, including the effects of hedging, to remain cash flow neutral after interest payments in 2016. We focused a substantial majority of our 2015 capital on our mature steamfloods, waterfloods and capital workovers, all of which offer among the highest investment performance metrics in our portfolio. 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, including many that would be economically viable even at current pricing. We are deferring these projects, however, given the capital constraints we have in 2016. We expect that in an improved commodity price environment, this diversified inventory will allow us to target drilling projects that can be funded through our internally generated cash flow.

Over the longer term, we develop our capital investment programs 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 the Value Creation Index (VCI) metric for project selection and capital allocation across our portfolio of opportunities. The VCI for each project is calculated 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 investment hurdle 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 portfolio of drilling opportunities. We intend to fund our currently limited capital investment program by reinvesting substantially all of our operating cash flow, while considering any potential deleveraging opportunities.

Approximately 55% of our 2015 production was generated by our world-class Elk Hills and Wilmington fields, which have produced over 1.9 and 2.9 billion barrels of oil equivalent (Boe) to date, respectively. The remaining 45% was generated through a combination of conventional primary, steamflood and waterflood projects as well as unconventional projects. In the last five years, we grew our total production 4% on a compounded annual basis, from an average of 138 MBoe/d in 2011 to 160 MBoe/d for the year ended December 31, 2015, while the proportionate share of oil production for the same period grew from 58% to 65%. The growth of our oil production during this period was approximately 7% compounded annually. Although with our limited capital program for 2016 we expect our production levels to decline, the percentage of our oil production should continue to increase over time and favorably impact our overall margins as we continue to direct virtually all of our capital investments toward oil-weighted opportunities to the extent the oil-to-gas price relationship remains favorable. For example, our steamflood projects provide some of the highest returns in our portfolio when the oil-to-gas price ratio exceeds five to one. As of December 31, 2015, the ratio was approximately 20 to one.

The following table summarizes certain information concerning our acreage, wells and drilling activities (as of December 31, 2015, acres and dollars in millions, unless otherwise stated):

	Acreage		Average Net Acreage Held in Fee (%)	Producing Wells, gross	Average Working Interest[1] (%)	Identified Drilling Locations[2]	
	Gross	Net				Gross	Net
San Joaquin Basin	1.9	1.6	62%	6,235	91%	19,150	13,000
Los Angeles Basin[3]	<0.1	<0.1	52%	1,385	89%	1,650	1,600
Ventura Basin	0.3	0.3	72%	735	90%	1,500	1,250
Sacramento Basin	0.6	0.5	36%	712	79%	1,150	900
Total	2.8	2.4	57%	9,067	88%	23,450	16,750

(1) For our 2015 production, our net revenue interest (NRI) was approximately 79%.

(2) Our total identified drilling locations include approximately 2,600 gross (2,250 net) locations associated with proved undeveloped reserves as of December 31, 2015. Our total identified drilling locations also include approximately 2,600 gross (2,300 net) injection well locations. Our total identified drilling locations exclude 6,400 gross (5,300 net) prospective resource drilling locations. Please see ''—Our Reserves and Production Information'' for more information regarding the processes and criteria through which we identified our drilling locations.

(3) We currently hold approximately 42,800 gross (34,700 net) acres in the Los Angeles basin. Our Los Angeles basin operations are concentrated with pad drilling.

In response to the deteriorating price environment that started in the second half of 2014 and continued in 2015, we significantly reduced our investment and drilling pace. During 2015, we operated an average of 3 drilling rigs across the state with two located in the San Joaquin basin (targeting steamflood activities) and one in the Los Angeles basin (targeting waterflood activities). We drilled 286 gross development wells with 254 wells in the San Joaquin basin and 32 in the Los Angeles basin. We also drilled 3 exploration wells in the San Joaquin basin.

In 2015, we also reduced our workover rig count from 51 at the beginning of the year to 33 at the end of the year to focus on projects that meet our investment criteria in the current environment. With significant operating control of our properties, we have the ability to adjust our drilling and workover rig count in 2016 based on commodity prices and are monitoring market conditions to increase or decrease our program accordingly. For example, we reduced our drilling rig count to zero at the beginning of 2016 in response to further weakness in oil prices.

In the third quarter of 2015, we announced a voluntary retirement program and other employee actions to align our workforce with our view of the commodity price environment. At the time of our Spin-off, we had about 2,000 employees. We ended the year with about 1,700 employees, representing a 15% reduction mainly through attrition and the third quarter employee actions. Since year end, we have implemented additional actions to reduce our workforce below 1,500 employees. We do not expect these actions to impact our production outlook; they will, however, reduce our operating costs and general and administrative expenses, as well as our drilling costs, and enhance our margins. Also, given the volatile oil price environment and our leverage, we began a hedging program shortly after the Spin-off to protect our cash flow and capital investment program and improve our ability to comply with our credit facility covenants in case of further price deterioration.

Our large acreage position contains numerous development and growth opportunities due to its varied geologic characteristics and multiple stacked pay reservoirs which, in many cases, are 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 with approximately 72% of our proved reserves associated with conventional opportunities. Conventional reservoirs are capable of natural flow using primary, steamflood and waterflood recovery methods. In 2015, we targeted our capital investments primarily toward conventional steamflood and waterflood development projects that we expected would contribute to near-term production and cash flow. We also have a significant portfolio of unconventional growth opportunities in lower permeability reservoirs that typically utilize established well stimulation techniques, which are subject to compliance with regulatory requirements. We have approximately 2,000 net identified drilling locations targeting unconventional reservoirs primarily in the San Joaquin basin. Prior to the severe price declines, we were focused on higher-value unconventional production from seven discrete stacked pay horizons within the Monterey formation, primarily within the upper Monterey. 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.

Over the past decade, we have also built a 3D seismic library that covers almost 4,700 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 returns from our portfolio. We intend to continue building our exploration inventory based on this data set and our experience and have begun marketing an exploration program to potential partners.

Our Business Strategy

Near-Term Strategy

Much of the global exploration and production industry is challenged at current price levels, putting pressure on the industry's ability to generate positive cash flow and access capital. In the current price and constrained capital environment, we intend to remain financially disciplined and prudent with our investments to maximize liquidity and remain compliant with our credit facilities in order to be positioned for an increase in commodity pricing. In response to the sharp price declines that began in the second half of 2014, we are focused on reducing our costs across our operations and deleveraging our balance sheet. We significantly reduced our 2016 planned capital program to $50 million from $401 million in 2015 when we emphasized projects and activities that focused on cash flow generation in the near term and met our investment criteria. The curtailment of the development of our properties will lead to a decline in our production and possibly our reserves. Over the long term, a continued decline in our production and reserves would reduce our liquidity and ability to satisfy our debt obligations by negatively impacting our cash flow from operations and the value of our assets. We will continue to employ cost saving measures to more efficiently deploy our capital and to decrease our unit lease operating and general and administrative expenses. We are also pursuing a number of alternatives to deleverage our balance sheet and better align our capital structure with the current commodity price environment.

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, including many that would be economically viable even at current pricing. We are deferring these projects, however, given the capital constraints we have in 2016. We expect that in an improved commodity price environment, this diversified inventory will allow us to target drilling projects that can be funded through our internally generated cash flow.

Long-Term Strategy

We plan to drive long-term shareholder value by applying modern technology 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 steamfloods, waterfloods and other enhanced recovery mechanisms. In the current price and constrained capital environment, we intend to remain financially disciplined and prudent with our investments to maximize liquidity. In a sustained higher price environment, we intend to direct any additional available and approved capital first to oil projects that provide long-term stable cash flows with low production declines and high returns, such as steamfloods and waterfloods. The principal elements of our long-term business strategy include the following:

- ***Focus on high-margin crude oil projects to generate sufficient cash flows to internally fund our capital budget.*** We expect the percentage of our oil production to continue to increase over time and favorably impact our overall margins as we anticipate directing virtually all of our capital investments towards oil-weighted opportunities in the near future to the extent the oil-to-gas price relationship remains favorable and capital is available. Approximately 96% of our identified drilling inventory is associated with oil-rich projects. At current prices, availability of capital will likely be constrained. In this environment, we intend to focus on continuing the cost efficiencies we delivered in 2015 and identifying additional value-creating opportunities in order to maintain self-funding as prices improve. To the extent we generate any free cash flow, we intend to fund our capital investment program while considering any deleveraging opportunities.

- ***Increase the share of conventional projects in our production mix to achieve lower declines and lower 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. When crude oil prices increase, we intend to focus the greater portion of our capital investments on such projects, which we expect will result in lower decline rates in our production. Over time, we expect that this strategy will reduce the capital required to maintain flat crude oil production. We have significant additional lower-risk conventional opportunities with 21,150 gross (14,750 net) identified drilling locations, 41% of which are associated with Improved Oil Recovery (IOR) and Enhanced Oil Recovery (EOR) projects. The remaining 59% are associated with primary recovery methods, many of which we expect will develop into IOR and EOR projects in the future.

- ***Proactive and collaborative approach to safety, environmental protection, and community relations.*** We are committed to managing our assets in a manner that safeguards people and protects the environment, and we seek to proactively engage with regulatory agencies, communities and other stakeholders to pursue mutually beneficial outcomes. As a California company, helping our state meet its water needs is a key strategic focus. Through our investments in water conservation and in recycling of produced water from oil and gas reservoirs, we are a net water supplier to agriculture. In 2015, our operations supplied more than 2.6 billion gallons of reclaimed water for irrigation, a 30% increase from 2014. This water supply to agriculture set a company record and again exceeded the volume of fresh water we purchased for our operations statewide. We continue to evaluate measures to further decrease our fresh water use and to expand the beneficial use of our produced water over the coming years.

- ***Continue to identify high-growth unconventional drilling opportunities.*** Over the longer term and in a higher oil-price environment, we believe we can generate significant production growth from unconventional reservoirs such as tight sandstones and shales. In such environment, we would expect to generate sufficient cash flow from our conventional projects to fund numerous unconventional opportunities in our portfolio. We hold mineral interests in approximately 1.3 million net acres with unconventional potential and have identified 2,300 gross (2,000 net) drilling locations on this acreage. As a result of our increased focus on these reservoirs over the past few years, a significant portion of our production now 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 unconventional 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 of our increased understanding of these reservoirs, 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.

- ***Apply proven modern technologies to enhance production growth.*** 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, or investments in other assets within their global portfolios. As an independent company focused exclusively on California, we intend, as capital becomes available, to make significant use of proven modern technologies in drilling and completing wells, as well as production methods, which we expect will substantially increase both our cost efficiency and production over time. We have developed an extensive 3D seismic library covering almost 4,700 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.

- ***Continued focus on our successful exploration program.*** As prices improve and sufficient additional capital becomes available, we intend to significantly increase our investment in exploration, focusing on both unconventional and conventional opportunities, primarily in areas that we believe can be quickly developed, such as those adjacent to our existing properties. In addition, we plan to explore and test new unconventional resource areas, which, if successful, could result in significant longer-term production growth. We are also actively pursuing joint venture partnership opportunities to implement our exploration programs.

Key Characteristics of our Operations

The following are among the key characteristics of our operations:

- ***Operational control of our diverse asset base provides flexibility over various commodity price ranges and preserves future value and growth potential in a higher price environment.*** Our near 100% operational control of 137 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 acreage position, approximately 60% of which we hold in fee, allows us to choose among multiple recovery mechanisms, including primary conventional, steamflood, waterflood and unconventional and to develop various products, including oil, natural gas and natural gas liquids (NGLs). Approximately 96% 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. We believe our low base decline positions us well to achieve growth in a higher price environment while living within our means.

- ***Relatively favorable margins driven by California's deficit energy market.*** 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. California imports over 60% of its oil and approximately 90% of its natural gas. A vast majority of the oil is imported via supertanker, with a minor amount arriving by rail. 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 country to California will continue contributing to higher realizations than most other United States oil markets for comparable grades. In addition, we own fee mineral interests on approximately 60% of our net acreage position. The returns on fee mineral acreage are enhanced because we do not pay royalties and other lease payments. To further improve our margins, we are opportunistically pursuing newly opened export markets for our crude oil production.

- ***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 2.4 million net acres. California is one of the most prolific oil and natural gas producing regions in the world and is the third largest oil producing state in the nation. It has five of the 12 largest fields in the lower 48 states based on proved reserves as of 2009, and our portfolio includes interests in four of these fields. California is also the nation's largest state economy, and the world's eighth 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 portfolio.*** Our drilling inventory at December 31, 2015 consisted of approximately 23,450 gross identified well locations, including 21,150 gross (14,750 net) conventional drilling locations and approximately 2,300 gross (2,000 net) unconventional drilling locations. Our drilling inventory count increased by about 16% from the prior year as a result of our technical teams' continued efforts. We have a large inventory of conventional development opportunities that we expect can provide stable lower-risk production with attractive returns based on capital availability. In a more favorable, sustained price environment, we believe we can also achieve long-term production growth through the development of unconventional reservoirs. In addition, our rich conventional and unconventional portfolio can provide attractive joint venture partnership opportunities, including in the current environment.

- ***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' experience in the oil and natural gas industry, with an average of over 15 years focused on our California oil and gas operations through multiple pricing cycles. Our operational management team and technical staff have a proven track record of applying modern technologies and operating methods to develop our assets and improve their operating efficiencies. For example, our teams have successfully reduced total field operating costs by approximately 13% on a per Boe basis in 2015 while increasing production in a challenging environment. Our teams are continuing to improve efficiencies across all our operations in 2016.

Portfolio Management and 2016 Capital Budget

We develop our capital investment programs 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 the VCI metric for project selection and capital allocation across our portfolio of opportunities.

We focused a substantial majority of our 2015 capital on our mature steamfloods, waterfloods and capital workovers, all of which offer among the highest VCIs in our portfolio. We focus on creating value and are committed to internally fund our capital budget with operating cash flows. Our low decline assets plus our high level of operational control and absence of long term commitments give us the flexibility to adjust the level of such capital investments as circumstances warrant. Of the total $401 million 2015 capital program, approximately $130 million was allocated to drilling wells, $120 million to facilities and compression expansion, $55 million to workovers, $40 million to maintenance and occupational health, safety and environmental projects, $15 million to exploration, $10 million to 3D seismic and the rest to other items.

For 2016, our board of directors approved a capital program of $50 million to maintain the mechanical integrity of our facilities and systems and operate them safely. In light of current commodity prices, we have built a dynamic budget for 2016 that adjusts our activity to align investments with operating cash flows. We will monitor prices and cash flow throughout the year and, if oil prices improve, may deploy additional available and approved capital focusing initially on a combination of capital workovers and new wells that meet our investment metrics. Our 2016 capital investment budget targets maintenance capital in the San Joaquin, Los Angeles and Ventura basins, and is expected to enhance the mechanical integrity and safety of our systems and infrastructure. Any capital increases will be directed almost entirely towards oil-weighted production consistent with our activity in 2015.

In addition, during this period of lower activity levels, we will continue to refine modern techniques that will enhance the value and growth potential of other parts of our portfolio that will not be funded in 2016 and will continue to build our inventory of available projects. This will position us to take advantage of improved market conditions when prices reach more favorable levels.

Reserves and Production Information

The table below summarizes our proved reserves and average production as of and for the year ended December 31, 2015 in each of California's four major oil and gas basins:

	Proved Reserves as of December 31, 2015						Average Net Daily Production for the Year Ended December 31, 2015		
	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBoe)	Oil (%)	Proved Developed (%)	(MBoe/d)	Oil (%)	R/P Ratio (Years)(1)
San Joaquin Basin	297	56	591	451	66%	72%	110	58%	11.2
Los Angeles Basin	130	—	11	132	98%	80%	34	100%	10.6
Ventura Basin	39	3	27	47	83%	77%	9	67%	14.3
Sacramento Basin	—	—	86	14	—	100%	7	—%	5.5
Total operations	466	59	715	644	72%	75%	160	65%	11.1

Note: MMcf 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.

(1) Calculated as total proved reserves as of December 31, 2015 divided by annualized Average Net Daily Production for the year ended December 31, 2015.

Marketing Arrangements

We market our crude oil, natural gas, NGLs and electricity in accordance with standard energy industry practices.

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 in place. California is heavily reliant on imported sources of energy, with over 60% of oil consumed during 2015 imported from outside the state, mostly from foreign locations. 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. Since California imports a significant percentage of its crude oil requirements, California refiners typically purchase crude oil at international waterborne-based prices. Currently, none of our index-based crude oil sales contracts have terms extending past 90 days. Beginning in late 2015, the U.S. federal government allowed the export of crude oil. As a result, we are opportunistically pursuing newly opened export markets for our crude oil production to improve our margins.

Given the volatile oil price environment, as well as our leverage, we began a hedging program shortly after the Spin-off to protect our cash flows, margins and capital investment program and improve our ability to comply with our credit facility covenants in case of further price deterioration. 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. Our existing Brent-based weighted-average oil hedge positions, substantially all of which were costless collars, including those entered into in early 2016, are as follows:

	Q1 2016	Q2 2016	Q3 2016	Q4 2016	2017	2018
Calls						
Barrels per Day	35,500	35,500	3,000	3,000	30,000	23,300
Wtd Avg Ceiling Price per Barrel	$ 66.15	$ 66.15	$ 74.42	$ 74.42	$ 55.68	$ 57.99
Puts						
Barrels per Day[(a)]	33,800	55,500	28,000	3,000	—	—
Wtd Avg Floor Price per Barrel[(a)]	$ 51.75	$ 50.14	$ 50.65	$ 50.00	$ —	$ —
Swap						
Barrels per Day	—	—	1,000	1,000	—	—
Weighted-Average Price per Barrel	$ —	$ —	$ 61.25	$ 61.25	$ —	$ —

(a) Q1 2016 averages include puts for 10,000 barrels of oil per day of our March 2016 production at $46 per barrel.

Natural Gas. California imports approximately 90% of the natural gas consumed in the state. We have firm transportation capacity contracts to access markets where necessary. These contracts are required 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 process substantially all of our NGLs through our processing plants, which facilitates 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.

Electricity. We provide part of the electrical output of our Elk Hills power plant to reduce Elk Hills field operating costs and increase reliability and sell the excess to the grid and to others under contract.

Our Principal Customers

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

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, 61% of our revenue. For the years ended 2014 and 2013, ConocoPhillips/Phillips 66 Company and Tesoro Refining & Marketing Company LLC each accounted for more than 10%, and, collectively, 45% and 42% of our revenue, respectively.

Title to Properties

As is customary in the oil and natural gas industry, 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 our properties. Such 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, our properties have been pledged as collateral to secure our credit facilities.

Competition

We have many competitors, some of which are larger and better funded, may be willing to accept greater risks or have special competencies. See ''Risk Factors.''

Regulation of the Oil and Natural Gas Industry

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, the production, transportation, and sale of our products, and the services we provide.

Regulation of Exploration and Production

California has regulations governing:

- oil and natural gas production including well spacing or density, on private and state lands;
- methods of constructing, drilling and completing wells, including well stimulation techniques such as hydraulic fracturing and acid matrix stimulation;
- design, construction, operation and maintenance of facilities, such as natural gas processing plants, power plants, compressors and pipelines;
- improved or enhanced recovery techniques such as fluid injection for waterflooding or steamflooding;
- sourcing and disposal of water used in the drilling, completion, stimulation 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 or operate wells and facilities; and
- occupational health, safety and environmental matters and the transportation and sale of our products as described below.

The Division of Oil, Gas, and Geothermal Resources (DOGGR) of the Department of Conservation is the state'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. In addition, specific aspects of our operations, such as occupational health, safety, air or water quality, labor, marketing and taxation, are regulated by other federal, state or local agencies. Collectively, the effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill.

For example, in 2013, California adopted Senate Bill 4 (SB 4), which mandates further regulation of certain well stimulation techniques, including hydraulic fracturing and acid matrix stimulation. Among other things, SB 4 requires:

- additional permitting of defined well stimulation treatments;
- prior notification to proximate property owners or lessees of proposed stimulation treatments, and pre- and post-stimulation groundwater sampling as requested by the owner or lessee;
- monitoring of groundwater quality in areas where well stimulation treatments occur, or concurrence that monitoring is not warranted due to a lack of protected water as defined by SB 4; and
- public disclosure of fluids used and other stimulation data, including data that may be considered proprietary or trade secret.

SB 4 also required state agencies to prepare an environmental impact report and scientific studies regarding well stimulation, which were published in 2015. Various state agencies are reviewing these studies to determine whether any additional regulation is warranted. In 2015, the U.S. Environmental Protection Agency (EPA) and the BLM adopted or proposed additional federal regulations on certain well stimulation operations. The implementation of well stimulation regulations and associated studies and reports have delayed and increased the cost of certain operations, and additional regulations may further increase costs and cause additional delays.

In addition, the Safe Drinking Water Act (SDWA) and analogous state laws regulate the injection of produced water, steam, natural gas or carbon dioxide into underground reservoirs for enhanced oil recovery or disposal. The state has issued permits for injection wells for decades under these laws. In 2015, the state imposed deadlines for obtaining confirmation from the EPA of aquifer exemptions under the SDWA to continue injecting and disposing produced water in certain fields. If the state or EPA were to rescind existing aquifer exemptions or permits for injection wells, reject new exemptions or permits or otherwise change the existing underground injection program, then our ability to inject produced water could be curtailed and our development and production activities could be negatively affected.

Finally, certain local governments have proposed or adopted ordinances that purport within their jurisdictions to regulate drilling activities in general, or stimulation and completion activities in particular, or to ban such activities outright. None of the adopted local ordinances is expected to materially impact our current or expected future operations. If new or more stringent federal, state, or local restrictions are adopted in areas where we operate, we could incur potentially significant added costs, experience delays or curtailment of our exploration or production activities and potentially be precluded from drilling wells or injecting fluids. Our competitors in the California oil and natural gas industry are generally subject to the same laws and regulations that affect our operations.

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, but are not limited to, 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. California imposes additional laws that are analogous to, and often more stringent than, such federal laws. These laws and regulations:

- require various permits and approvals before drilling, workovers, 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 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;
- 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 or transportation activities;
- limit or prohibit operations on lands lying within coastal, wilderness, wetlands, groundwater recharge, endangered species habitat, and other protected areas;
- establish standards for the closure, abandonment, cleanup or restoration of former operations, such as plugging of abandoned 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 or wastes 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 by governmental authorities, special interest groups and other claimants; and
- may restrict our rate of oil, NGLs, natural gas and electricity production.

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.

Federal, state and local governments frequently revise health, safety and environmental laws and regulations, and any changes that result in delays or more stringent permitting, materials handling, engineering, disposal, cleanup and restoration requirements for the oil and gas industry could have a significant impact on our capital investments and operating costs. Failure to comply with existing or new laws and regulations may result in the assessment of administrative, civil or criminal fines and penalties and liability for non-compliance, costs of corrective action, installation of pollution control equipment, cleanup and restoration, compensation for personal injury, property damage or other losses, and the imposition of injunctive or declaratory relief that may delay, modify or prevent development, construction or operations. Releases, discharges or other accidents may occur in the course of our operations and may result in significant costs and liabilities, including governmental or third-party claims for personal injury or damage to property or natural resources.

Regulation of Climate Change and Greenhouse Gas (GHG) Emissions

A number of international, federal, state, and regional efforts seek to prevent or mitigate the effects of climate change or to track or reduce GHG emissions associated with 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 regulations to restrict GHG emissions from certain mobile sources, require certain operations, including onshore and offshore oil and natural gas production facilities, to monitor and report GHG emissions on an annual basis, and incorporate measures to reduce GHG emissions in permits for certain facilities.

In 2006, California adopted Assembly Bill 32 (AB 32), which established a statewide ''cap-and-trade'' program for GHG emissions. Under the program, which commenced in 2012, the California Air Resources Board (CARB) set a statewide maximum limit on total GHG emissions, and this cap declines annually through 2020. CARB requires us, and other businesses in the oil and natural gas production sector, to report GHG emissions. We are required to obtain allowances or qualifying offset credits for each metric ton of GHGs emitted from our operations and from the sale of certain products to customers for use in California. The state grants a portion of the allowance, but we must make up any shortfall by purchasing additional allowances from either the state or a third party. The availability of allowances will decline over time, and the cost to acquire such allowances may increase. The cap-and-trade program currently expires in 2020. California Senate bills in 2014 and 2015 proposed to extend the program to 2050. Although those bills were not adopted, similar legislation may be proposed in the future.

In 2015, the California cap-and-trade program began to cover emissions from the sale of propane and liquid transportation fuels for use in the state. Producers or marketers of propane and refiners of liquid transportation fuels will be responsible for retiring allowances equivalent to the metric tons of carbon dioxide estimated to be produced from the combustion of the propane and transportation fuels they market for use in California. Under AB 32, CARB has also imposed a ''low carbon fuel'' standard, which requires refiners to reduce the carbon content of transportation fuels they market in California by 10% by 2020. In 2015, California enacted SB 350, which established goals to derive 50% of California's electricity from renewable sources and to double the energy efficiency of buildings in the state by 2030. The Governor's stated goal to reduce petroleum use in cars and trucks by 50% from current levels was not enacted by the Legislature, but may be the subject of additional regulations by CARB. At the United Nations Climate Conference in Paris in December 2015, California's Governor announced that the state is seeking to create a western regional electricity market and to incorporate certain U.S. states, Canadian provinces and cities in other countries into California's cap-and-trade program. These programs and policies, as well as federal and California subsidies and tax incentives for the development and construction of alternative energy-fueled power generation and transportation, may reduce demand for our products and services or require further controls on, or modifications to, our operations.

If we are unable to recover or pass through a significant portion of our costs related to complying with climate change regulations, these regulations could materially affect our operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of, and access to, capital. Future legislation or regulations adopted to address climate change could also make our products more or less desirable than competing sources of energy.

Regulation of Transportation and Sale of Our Products

Our sales prices of oil, NGLs and natural gas in the United States 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, which will allow the sale of our oil production in additional markets, and may affect the prices we realize.

Interstate transportation rates for oil, natural gas and NGLs are regulated by the Federal Energy Regulatory Commission (FERC). The FERC has established an indexing system for such transportation, which allows pipelines to take an annual inflation-based rate increase. We are not able to determine the effect, if any, these regulations have on us, but, other factors being equal, the regulations may, over time, tend to increase transportation costs, which may affect our margins.

Market Manipulation and Market Transparency Regulations

Under the Energy Policy Act of 2005, the FERC possesses regulatory oversight over natural gas and power markets to prevent market manipulation. The Federal Trade Commission has similar regulatory oversight of oil markets to prevent market manipulation. The Commodity Futures Trading Commission (CFTC) also holds authority over the physical and futures energy commodities market pursuant to the Commodity Exchange Act. We are required to observe these laws and related regulations when we engage in physical purchases and sales of oil, NGLs and natural gas and when we engage in hedging activity. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. We could also be subject to related third-party damage claims for violation of these laws brought by, among others, sellers, royalty owners and taxing authorities. In addition, the FERC has issued market transparency rules for natural gas and power that affect some of our operations and impose reporting and other obligations on us.

Natural Gas Gathering Regulations

Section 1(b) of the federal Natural Gas Act exempts natural gas gathering facilities from the jurisdiction of the FERC. We own certain natural gas pipelines that we believe meet the traditional tests that FERC has used to establish a pipeline's status as a gathering line not subject to FERC jurisdiction. The distinction between FERC-regulated transmission facilities and federally unregulated gathering facilities is, however, the subject of ongoing litigation, and is otherwise subject to potential change.

In addition to the federal and state laws described above under the heading ''Business— Regulation of Health, Safety and Environmental Matters,'' our natural gas gathering operations are subject to state statutes designed to prohibit discrimination favoring producers or sources of supply. The regulations may restrict those with whom we contract to gather natural gas. In addition, our natural gas gathering operations could become subject to more stringent application of state or federal regulation of rates and services, though we do not believe any such action would affect us materially differently than our competitors.

Regulation of Power Sales and Transmission

The FERC regulates the sale of electricity at wholesale and the transmission of electricity under the Federal Power Act. The FERC's jurisdiction includes, among other things, authority over the rates, charges and other terms for the sale of electricity at wholesale by public utilities and for transmission services. In most cases, the FERC does not set rates for the sale of electricity at wholesale by generating companies (such as our subsidiary) that qualify for market-based rate authority, which allows companies to negotiate market rates. In order to be eligible for market-based rate authority, and to maintain exemptions from certain FERC regulations, our subsidiary has been granted market-based rate authorization from the FERC.

Employees

Our future success will depend partially on our ability to attract, retain and motivate qualified employees. 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. Approximately 85 of our employees are represented by labor unions. We have not experienced any strikes or work stoppages by our employees in the past 36 years or longer.

In the third quarter of 2015, we announced a voluntary retirement program and other employee actions to align our workforce with our view of the price environment. At the time of the Spin-off, we had about 2,000 employees. As of December 31, 2015, we had approximately 1,700 employees, representing a 15% reduction mainly through attrition and the third quarter employee actions. Since year end, we have implemented additional actions to reduce our workforce below 1,500 employees.

Effective January 1, 2015, we adopted the California Resources Corporation 2014 Employee Stock Purchase Plan (ESPP). 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 fiscal quarter, whichever amount is less. At January 1, 2016, over 50% of our employees had elected to participate in the plan.

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, 5 and 10; and
- Corporate governance information, including our corporate governance guidelines, board-committee charters and code of business conduct (see Part III, Item 10, of this report for further information).

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 the business activities we conduct. 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.

Risks Related to Our Business and Industry

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

Our financial results, financial condition, cash flow and ability to grow correlate closely to the prices we obtain for our products. Since 2014, global energy commodity prices have declined significantly. For example, Brent crude prices declined from over $110 per barrel in June 2014 to below $30 per barrel in January 2016. Continued low prices for our products or further price decreases could have several negative effects described in greater detail below, including:

- reduced cash flow, decreased funds available for capital investments as well as costs incurred to reduce our labor force and otherwise adjust our cost structure;
- reduced proved oil and gas reserves and related cash flows;
- further impairments of our oil and gas properties such as we experienced in 2014 and 2015; and
- reduced borrowing base capacity under our credit facility as oil and gas reserves values fall, with the potential for a reduction of our liquidity, mandatory loan repayments and default and foreclosure by our banks on our secured assets.

Product prices can fluctuate widely and 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 and refining disruptions, currency exchange rates, worldwide drilling and exploration activities, the effects of conservation, weather, geophysical and technical limitations, refining and processing disruptions, transportation bottlenecks and other matters affecting the supply and demand dynamics for our products; technological advances and regional market conditions; transportation capacity and costs in producing areas; 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 protection for a significant portion of our 2016 production, they may not adequately protect us from commodity price fluctuations and we may be unable to enter into acceptable additional hedges.

The sustained downturn in the price of crude oil since 2014 has affected, and may further materially and adversely affect, our financial position, the quantities of natural gas and oil reserves that we can economically produce, our cash flow available for interest payments, operational expenses and capital investments, our need to post cash collateral or provide letters of credit, our relationships with, or ability to attract, counterparties to our transactions, including hedging transactions, our ability to access funds under our revolving credit facility and through the capital markets and the price we could obtain for asset sales or other monetization transactions.

Our lenders can limit our borrowing capabilities, which may materially impact our ability to use or access capital, worsening any reduction in our cash flows and limiting our business activities.

On February 23, 2016, we amended our credit facilities which reduced our borrowing base to $2.3 billion and the lenders' revolving facility commitments to $1.6 billion. At January 31, 2016, we had approximately $1.7 billion of outstanding debt under our revolving credit and term loan facilities, resulting in approximately $560 million of availability, under the new $2.3 billion borrowing base. We may need to depend on our revolving credit facility for a portion of our future capital or operating needs. Our ability to borrow under our revolving credit facility will be further limited by our ability to comply with its covenants, including quarterly financial covenants.

As amended, our financial performance covenants through December 31, 2016 comprise an obligation to achieve (i) a cumulative minimum EBITDAX during 2016 of $55 million through the first quarter, $130 million through the second quarter, $190 million through the third quarter and $250 million through the fourth quarter and (ii) a trailing twelve-month minimum interest coverage ratio of 2.00:1.00 as of the end of the first quarter of 2016, 1.50:1.00 as of the end of the second quarter, 1.25:1.00 as of the end of the third quarter, and 0.70:1.00 as of the end of the fourth quarter. As of the end of the first quarter of 2017, the minimum interest coverage ratio will revert back to 2.00:1.00. We will not be subject to a maximum first lien senior secured leverage ratio for 2016. The amendment also suspends the requirement for us to comply with a trailing twelve-month maximum first lien senior secured leverage ratio of 2.25:1.00 until the end of the first quarter of 2017. Compliance with the first-lien senior secured leverage and the interest expense ratios in the first quarter of 2017 would require prices significantly higher than current prices.

Except as otherwise agreed with our lenders for specific transactions, our credit facilities as amended require us to apply 100% of the proceeds from certain asset monetizations to repay loans outstanding under the credit facilities, except that we will be permitted to use up to 40% of proceeds from non-borrowing base asset sales to repurchase our notes to the extent available at a significant minimum discount to par as specified in the amended facilities. Subject to compliance with our indentures, our amended facilities permit us to incur additional indebtedness to repurchase our notes to the extent available at a significant minimum discount to par, as specified in the amended facilities, as follows: (i) up to $1 billion, which may be secured by liens that are junior to the liens securing our credit facilities, provided that at least 60% of the proceeds from the new debt is used first to repay loans outstanding under the credit facilities, and (ii) up to $200 million, which may be secured by first-priority liens on our non-borrowing base properties. The amended credit facilities also permit us to incur up to an additional $50 million of non-credit facility indebtedness, which, subject to compliance with our indentures, may be secured; and the proceeds of which must be applied to repay loans outstanding under the credit facilities. All of the foregoing prepayments will be applied first to our term loan and second to our revolving loans after the term loan has been fully repaid (with a corresponding reduction to the lenders' revolving loan commitments). Our amended facilities also require us to apply cash on hand in excess of $150 million to repay amounts outstanding under our revolving credit facility. Further, we are restricted from (i) paying dividends or making other distributions to common stockholders and (ii) making capital investments exceeding $100 million during 2016.

The amendment also imposed a semi-annual borrowing base redetermination each May 1 and November 1, commencing May 1, 2016. The borrowing base will be based upon a number of factors, including commodity prices and reserves levels. Increases in our borrowing base requires approval of at least 80% of our revolving lenders, as measured by exposure, while decreases require a two-thirds approval. We and the lenders (requiring a request from the lenders holding two-thirds of the revolving commitments and outstanding loans), each may request a special redetermination once in any period between three consecutive scheduled redeterminations. Upon a redetermination, our borrowing base could further be substantially reduced, and in the event the amount outstanding under the revolving credit facility at any time exceeds the borrowing base at such time, we may be required to repay a portion of our outstanding borrowings. In that event, we may not have sufficient funds to make such repayments and may be unable to arrange new financing or sell sufficient assets and could default under our credit facilities. If we are able to take action sufficient to refund a repayment obligation it may significantly affect our business or financial results. Any reduction in our borrowing base could limit our access to capital to fund our capital program, other obligations and business activities.

Substantially all of the restrictions imposed by the recent amendment to the credit facilities, other than the requirement for semi-annual borrowing base redeterminations, may terminate in the future if we are able to comply with the financial performance covenants as they existed prior to giving effect to the amendment. If we were to breach any of our credit facility covenants, our lenders would be permitted to accelerate the principal amount due under the credit facilities and foreclose on the assets securing them. If payment were accelerated under our credit facilities, it would result in a default under our outstanding notes and permit acceleration and foreclosure on the assets securing the secured notes.

Continued reduced commodity prices and lower operating cash flows, coupled with substantial interest payments, would severely constrain our liquidity.

The primary source of liquidity and capital resources to fund our capital program and other obligations is cash flow from operations and borrowings under our revolving credit facility. As noted above, our borrowing capacity is limited. At current price levels, we estimate that our capital budget for 2016 will be approximately $50 million.

Further price declines would further reduce our cash flows from operations and may limit our access to borrowing capacity or cause default under our revolving credit facility as discussed above. If we are unable to achieve improved liquidity through additional financing, asset monetizations, restructuring of our debt obligations or otherwise, cash flow from operations and expected available credit capacity may not be sufficient to meet our commitments over the next twelve months.

We continue to evaluate asset monetization transactions and other alternatives to manage our debt capital structure. We cannot assure that any of these efforts will be successful or will result in sufficient cost reductions or additional cash flows or the timing of any such cost reductions or additional cash flows. We recently completed an exchange of newly-issued second lien secured notes for outstanding senior unsecured notes that may deplete a significant portion of our net operating losses such that we may not have sufficient net operating losses available to offset future gains. Additionally, if the current conditions persist, we expect our production levels would decrease as we intend to continue to limit our capital program, which would further reduce cash flow.

We have significant indebtedness and may incur more debt. Higher levels of indebtedness could make us more vulnerable to economic downturns and adverse developments in our business or otherwise limit our operational flexibility.

As of December 31, 2015, we had $6.1 billion of consolidated indebtedness comprised of senior unsecured notes, second lien secured notes and secured credit facility borrowings. At January 31, 2016, we had approximately $1.7 billion of outstanding debt under our revolving credit and term loan facilities, resulting in approximately $560 million of availability, under our $2.3 billion borrowing base in effect as of February 2016 and subject to compliance with our quarterly financial covenants.

In addition, the indentures governing our outstanding notes and our credit agreement permit us to incur significant additional indebtedness as well as certain defined obligations, unrestricted by debt incurrence or lien covenants, or that do not constitute indebtedness.

Indebtedness outstanding under our credit facilities bears interest at a variable rate, therefore a rise in interest rates will generate greater interest expense if and to the extent we do not purchase interest rate hedges.

Our level of indebtedness may have several important consequences, including, without limitation:

- jeopardizing our ability to continue executing our business plans;
- increasing our vulnerability to adverse changes in our business and to general economic and industry conditions, and 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 additional financing for working capital, capital investments and general corporate and other purposes or increasing the cost of that capital; and
- limiting our flexibility to operate our business, react to competitive pressures and adverse regulatory changes and engage in certain transactions that might otherwise be beneficial to us.

The covenants under the credit agreement and note indentures may limit, among other things, our ability to:

- incur indebtedness;
- make investments;
- make restricted payments;
- create liens on certain assets forming the borrowing base for our credit facilities;
- sell assets that constitute borrowing base collateral;
- engage in mergers or acquisitions; and
- release collateral.

Our ability to meet our debt obligations and other financial needs will depend on our future performance, which will be affected 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 sell 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 under that indebtedness. 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 of assets subject to our secured credit facilities and secured notes.

If we fail to comply with the continued listing standards of the New York Stock Exchange (NYSE), it may result in a delisting of our common stock from the NYSE.

Our common stock is listed on the NYSE. Continued listing is subject to compliance with a number of listing standards. We were recently notified by the NYSE that we were out of compliance with minimum standards because the average closing price of our common stock as reported on the consolidated tape was less than $1.00 over a consecutive 30 trading-day period. NYSE rules provide issuers six months from NYSE notification of a deficiency to cure noncompliance with the stock price listing standard before the NYSE begins suspension and delisting procedures. An issuer can regain compliance at any time during the six-month cure period if, on the last trading day of any calendar month during the cure period, the company has a closing stock price of at least $1.00 and an average closing stock price of at least $1.00 over the 30 trading-day period ending on the last trading day of that month. Additionally, if our common stock trades at a price below $0.16 per share at any time, the NYSE has advised that they may immediately suspend the trading of our common stock and initiate delisting procedures without an opportunity to cure the listing deficiency.

Subject to board approval, we intend to seek stockholder approval to effect a reverse stock split not later than our Annual Meeting in May. There can be no assurance that stockholders will grant approval or that the deficiency will be cured by subsequent trading prices. Any delisting of our common stock from the NYSE could result in even further reductions in our stock price, would substantially limit the liquidity of our common stock, and would materially adversely affect our ability to raise capital or pursue strategic restructuring, refinancing or other transactions on acceptable terms, or at all. Any delisting from the NYSE could also have other negative results, including the potential loss of investor confidence.

Our business requires substantial capital investments. 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 continue to make substantial capital investments for the development and exploration of oil and gas reserves. We invested $401 million of capital during the year ended December 31, 2015, funded by our operating cash flow and were able to minimize production declines. At current price levels, we plan to invest approximately $50 million under our 2016 capital program, which will be funded primarily through cash flow from operations and borrowings under our revolving credit facility. The new amendment to our credit facilities does not permit us to incur capital expenditures in 2016 in excess of $100 million. We expect our planned reductions in capital investment in 2016 to cause our production to decline, and they will begin to reduce our cash flows and possibly our reserves.

Our ability to deploy capital as planned over the long term depends on a number of variables, including: (i) commodity prices and market access; (ii) regulatory and third-party approvals; (iii) our ability to timely drill wells due to technical factors and contract terms; (iv) the availability of capital, equipment, services and personnel and (v) drilling and completion costs and results. Because of these and other potential variables, we may be unable to deploy capital in the manner planned and actual development activities may materially differ from those presently anticipated.

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.

During the course of 2015, we experienced significant and extended price declines from 2014, which impacted the quantity of reserves we reported as of December 31, 2015. The unweighted arithmetic average first-day-of-the-month price for Brent oil decreased from $101.30 per barrel for 2014 to $55.57 per barrel for 2015. As a result we experienced negative price related revisions to our proved reserves at December 31, 2015 of 153 MMBoe. 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 rules or may be removed due to a lower amount of capital available to develop these projects within the SEC-mandated five-year limit. For example, in 2015 we recategorized 69 million barrels of proved undeveloped reserves as unproved reserves as a result of these constraints and a significant reduction in pricing for 2016 from 2015 may require us to impair or recategorize reserves again in 2017. Our production-sharing contracts in Long Beach tend to partially offset these effects because our share of production and reserves from these contracts increases as prices decline. Cost reduction and efficiency efforts also offset a portion of the price-related loss of reserves quantities as some of the barrels that would have become uneconomic in later years remain economic, a portion of the proved undeveloped reserves that would otherwise be removed from the reserves quantities become economic and we expect to drill more wells with the same amount of capital. We can give no guarantee, however, that we will ultimately be able to continue to realize reductions and efficiencies as we seek to produce our reserves. If the SEC prices for the December 31, 2015 reserves determination were about $10 lower than those actually used, we believe our reserves quantities may have been lower by less than 15%. This estimate does not reflect the effect of further cost savings that we expect to achieve in 2016.

In addition, our reserves information represents estimates prepared by internal engineers. Although over 80% of these 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 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 remedial costs.

Misunderstanding of the variables, inaccurate assumptions, changed circumstances or new information could require us to make significant negative reserves revisions.

We currently expect improved recovery, extensions and discoveries to be our main sources for reserves additions, but factors such as geology, government regulations and permits and the effectiveness of development plans are partially or fully outside management's control and could cause unforeseen results. Any material inaccuracies in these reserves estimates or underlying assumptions could materially affect the quantities and net present value of our reserves, which could adversely affect our business and results of operations.

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

Our disposition activities carry risks that (i) we may not be able to realize reasonable prices for assets we sell; (ii) we may be required to retain liabilities that are greater than desired or anticipated; and (iii) we may lose synergies among elements of our business. 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, such as the recent deterioration of oil and natural gas prices; (ii) bear unexpected integration costs or experience other integration difficulties; (iii) experience share price declines based on the market's evaluation of the activity or (iv) assume liabilities that are greater than anticipated.

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.

Unless we replace crude oil and natural gas reserves, our future reserves and production will decline.

Our total proved reserves decline as reserves are produced unless we conduct successful exploration and development activities or acquire properties containing proved reserves, or both. Our reduced expected capital investment in 2016 may result in a future decline in our reserves. To the extent cash flow from operations and external sources of capital remain limited or become unavailable, our ability to make the necessary long-term capital investments needed to maintain or expand our asset base of crude oil and natural gas reserves may be impaired. We may not be successful in developing, exploring for or acquiring additional reserves. We also may not be successful in raising funds to acquire 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 negatively affecting our cash flow from operations and the value of our assets.

Our business is highly regulated and governmental authorities can delay or deny permits and approvals or change legal requirements governing our operations, including hydraulic fracturing and other well stimulation, enhanced production techniques and fluid 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, the production, transportation and sale of our products, and the services we provide. See the section of our Annual Report on Form 10-K entitled ''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 governmental authorities. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and 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 limiting our 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, are also highly regulated. For example, the recent release of natural gas from a utility's Aliso Canyon natural gas storage facility in California may result in new regulations that could affect the demand or availability of storage for natural gas, add 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. Certain government agencies have adopted or proposed new or more stringent requirements for permitting, well construction, public disclosure or environmental review of, or restrictions on, certain oil and gas operations, including drilling, completion, well stimulation, enhanced production techniques, fluid disposal, water recycling and reuse, remediation and closure and decommissioning of our facilities. Such new requirements or restrictions or resulting litigation could result in potentially significant added costs to comply, delay or curtail our exploration, development, or production activities, and preclude us from drilling or stimulating wells, which could impair our expected production over the longer term.

Tax law changes may adversely affect our operations.

In California, there have been proposals for tax increases for the past several years including a severance tax as high as 12.5% of the value of petroleum production in California. Although the proposals have not become law, campaigns by various interest groups could lead to future oil and gas severance taxes. The imposition of such a tax could severely reduce our profit margins and cash flow and could ultimately result in lower oil and natural gas production, which may reduce our capital investments and growth plans.

In addition, President Obama's budget proposal for fiscal year 2017 recommended the elimination of certain federal income tax preferences currently available to oil and gas exploration and production companies as well as new taxes, all of which could harm us. The elimination of tax preferences includes (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of expensing intangible drilling costs, (iii) an increase in the amortization period from two years to seven years for geological and geophysical costs paid or incurred by independent producers and (iv) repealing the domestic manufacturing deduction for income derived from the production of oil and gas in the United States.

The new taxes on oil companies proposed by President Obama include (i) a $10.25 per Boe tax and (ii) a reinstatement of the Superfund excise tax. If enacted, the new oil tax would be collected on domestically produced crude oil. The oil tax would be phased in over a five-year period beginning October 1, 2016. The reinstatement of the Superfund excise tax would be for taxable years beginning after December 31, 2016 through December 31, 2026.

Drilling for and producing oil and natural gas carry significant operational and financial risk and uncertainty.

Unless we conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our decisions to explore, develop, purchase or otherwise exploit prospects or properties will depend in part on the evaluation of geophysical, geologic, engineering, production and other technical data, the analysis of which is often inconclusive or subject to varying interpretations. Our cost of drilling, completing, equipping and operating wells is also often uncertain. Overruns in budgeted investments are a common risk that can make a particular project uneconomical or less economical 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 response to improved recovery or enhanced recovery efforts, and other associated risks.

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

Our operations are geographically concentrated exclusively in California. Because of this geographic concentration, the success and profitability of our operations may be disproportionately exposed to the effect of regional events. 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, marine and rail transportation capacity constraints, 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. For example, we experienced higher discounts to index prices in the early part of 2015, which reflected the result of local refinery and pipeline events and local price posting mechanisms.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing and other well stimulation techniques could cause us to incur increased costs and experience additional operating restrictions or delays.

Hydraulic fracturing involves the injection of fluid under pressure into underground rock formations containing oil and natural gas to create or enlarge fractures to stimulate production by allowing fluids to flow more freely into the oil and gas well. In 2013 California adopted SB 4, which mandated further regulation of certain well stimulation techniques, including hydraulic fracturing and acid matrix stimulation. Among other things, SB 4 requires operators to obtain specific well stimulation permits, notify proximate property owners or lessees of proposed stimulation treatments, disclose the fluids used and other stimulation data and implement groundwater monitoring and water management plans. In addition, the EPA and the BLM adopted or proposed additional federal regulations in 2015 on certain well stimulation operations. The implementation of federal and state well stimulation regulations and associated studies and reports have delayed and increased the cost of certain operations, and additional regulations may further increase costs and cause additional delays.

In addition, certain local governments have proposed or adopted ordinances that purport, within their jurisdictions, to regulate certain drilling activities in general, or well stimulation or completion activities in particular, including hydraulic fracturing, or to ban such activities outright. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

Restrictions on our ability to obtain, use, manage or dispose of water may have an adverse effect on our operations.

Water management is an essential component of our operations. We treat and re-use water for a substantial portion of our needs related to activities such as steamflooding, waterflooding, pressure management, well completion and stimulation, including limited hydraulic fracturing, and we provide reclaimed water for agricultural use in certain areas. 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. Due to severe drought in California, some local and regional water districts and the state government are implementing regulations and policies that restrict water usage and increase the cost of water.

Existing laws and regulations restrict our ability and increase our cost to manage and dispose of water and other fluids. The federal Clean Water Act and Safe Drinking Water Act and analogous state laws impose restrictions and strict controls on the discharge of and injection of fluids, including produced water. We must obtain permits or waivers for certain surface discharges and subsurface injection, as well as for construction activities that may affect regulated water resources. Certain government agencies have investigated and continue to study whether the discharge or injection of produced water could affect water quality or induce ground movement or seismicity, which may result in additional regulations under federal and state laws. Our enhanced production operations or fluid disposal could give rise to litigation over claims related to alleged damage to the environment or private or public property. The laws, regulations, policies and attendant liabilities relating to the use, disposal and injection of water and other fluids could increase our costs and negatively affect our development and production activities.

We may not drill our identified sites at the times we scheduled or at all and sites we decide to drill may not yield crude oil or natural gas in economically producible quantities.

We have specifically identified locations for drilling over the next several years. These drilling locations represent a significant part of our long-term growth strategy. Our ability to profitably drill and develop these locations depends on a number of variables, including crude oil and natural gas prices, the availability of capital, 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. The risk profile for our exploration and prospective drilling locations is higher than for other locations because we have less geologic and production data and drilling history, in particular for our prospective resource locations, 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. We cannot guarantee that these prospective 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 19% of our total net undeveloped acreage at December 31, 2015. Our actual drilling activities may materially differ from those presently identified.

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.

Investment in exploration carries inherent operational and financial risk and its results are unpredictable. The results of our exploratory drilling in new or emerging plays are more uncertain than drilling results in areas that are developed and have established production, and we may increase the proportion of our drilling in new or emerging plays over time. 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.

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 our ability, the timing or the cost to develop this asset.

Our Area of Mutual Interest (AMI) Agreement may limit our ability to operate outside of California.

In connection with the Spin-off, we entered into an AMI Agreement, which provides Occidental with the right to acquire a 51% interest in, and rights with respect to, certain oil and gas properties we acquire in the United States, other than in the State of California, for five years following the completion of the Spin-off. If we were to change our current strategy of focusing exclusively on opportunities in California, the AMI Agreement could adversely affect our ability to pursue opportunities outside of California during the five years following the Spin-off.

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 commodity-price, interest-rate and other 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 CFTC 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 negatively affect our revenues and cash flow during periods of low commodity prices. While many Dodd-Frank Act regulations are already in effect, the rulemaking and implementation process is ongoing, and the ultimate effect of the adopted rules and regulations and any future rules and regulations on our business remains uncertain.

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.

Our commodity-price risk-management and trading 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 stated in the derivative instruments used to manage price risk. In addition, our commodity-price risk-management and trading activities may expose us to the risk of financial loss in certain circumstances, including instances in which the following occur:

- a change in price basis differentials;
- the counterparties to our hedging or other price-risk management contracts fail to perform under those arrangements;
- an event materially impacts oil and natural gas prices in the opposite direction of our derivative positions; and
- our production is materially less than the notional volumes.

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

Concerns about climate change and regulation of greenhouse gases (GHGs) may 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. In addition, legislative and regulatory responses to climate change may increase our operating costs. California has led other states in adopting GHG emission reduction requirements as well as mandates for renewable fuel sources. In 2006, California adopted AB 32, which established a statewide cap on GHG emissions, including on the oil and natural gas production industry, and a ''cap-and-trade'' program. Since 2012, California Air Resources Board (CARB) regulations have required us to obtain GHG emissions allowances corresponding to reported GHG emissions from operations and, starting in 2015, from the sale of certain products to customers for use in California. In 2015, we incurred approximately $21 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 reduces the number of available allowances, increases their targeted price and covers more operations and products in the program.

The EPA has also adopted regulations requiring the reporting of GHG emissions from certain onshore oil and natural gas production facilities on an annual basis. In 2015, the EPA expanded the scope of the GHG monitoring and reporting rule to include gathering and compression facilities as well as completions and workovers from wells that have undergone hydraulic fracturing. The EPA also proposed regulations in 2015 that would require emission controls for methane from certain equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. These additional regulations could increase our costs.

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 and electricity generation, impose additional taxes and costs on producers and consumers of petroleum products and require or subsidize the use of renewable energy, which could increase our costs and reduce demand for our products and services.

Federal and state regulatory agencies 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 many instances more stringent than analogous federal laws and regulations. As these requirements become more stringent, we may be unable to implement them in a cost-effective manner. As a result of existing and future air quality initiatives, we could face risks of increased costs and taxes, an inability to execute projects and reduced demand for our products and services.

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, including well stimulation and completion activities, are subject to operating risks associated with drilling for and producing oil and natural gas, such as fires, explosions, releases, discharges, equipment failures and industrial accidents. Other catastrophic events such as earthquakes, floods, mudslides, wildfires, droughts, terrorist attacks and other events that cause operations to cease or be curtailed may negatively affect our business 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.

Cyber attacks could affect us significantly.

Cyber attacks on businesses have escalated in recent years. We rely on electronic systems and networks to communicate, control and manage our operations and prepare our financial management and reporting information. 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.

Risks Related to the Spin-off

In connection with our separation from Occidental, we agreed to indemnify Occidental for certain liabilities, including those related to the operation of our business while it was still owned by Occidental, and Occidental agreed to indemnify us for certain liabilities, which indemnities may not be adequate.

Pursuant to agreements with Occidental, Occidental has indemnified us for certain liabilities, and we agreed to indemnify Occidental for certain liabilities, in each case for uncapped amounts. Indemnity payments that we may be required to provide Occidental may be significant and could negatively impact our business, particularly indemnity payments relating to our actions that could impact the tax-free nature of the Spin-off. Third parties could also seek to hold us responsible for liabilities that Occidental has agreed to retain. Further, there can be no assurance that the indemnity from Occidental will be sufficient or timely to protect us against the full effect of such liabilities.

Our Tax Sharing Agreement with Occidental may limit our ability to take certain actions, including strategic transactions, and may require us to indemnify Occidental for significant tax liabilities.

Under the Tax Sharing Agreement between Occidental and CRC, we have agreed to take certain actions or refrain from taking certain actions to ensure that the Spin-off and certain transactions taken in preparation for, or in connection with, the Spin-off qualify for tax-free status under the relevant provisions of the Internal Revenue Code of 1986, as amended (the ''Code''). We have also made various other covenants in the Tax Sharing Agreement intended to ensure the tax-free status of the Spin-off. These covenants restrict our ability to sell assets outside the ordinary course of business, to issue or sell additional common stock or other securities (including securities convertible into our common stock), or to enter into certain other corporate transactions. For example, for a period of two years after the final disposition of the securities retained by Occidental after the Spin-off, absent approval by Occidental, we may not enter into any transaction that would be reasonably likely to cause us to undergo either a 30% or greater change in the ownership of our voting stock or a 30% or greater change in the ownership (measured by vote or value) of all classes of our stock.

We have agreed to indemnify Occidental for (a) taxes incurred as a result of the failure of the Spin-off or certain transactions undertaken in preparation for, or in connection with, the Spin-off to qualify as tax-free transactions under the relevant provisions of the Code to the extent caused by (i) our breach of certain tax-related representations or covenants made in connection with the Spin-off, (ii) actions, failures to act and omissions inconsistent with such representations and covenants and (iii) certain permitted transactions, and (b) any finally determined increases of our liability for separate tax items included in combined or consolidated Occidental returns. We also have agreed to pay 50% of any taxes arising from the Spin-off or related transactions to the extent that the tax is not attributable to the fault of either party. In addition, we have agreed to indemnify Occidental and its remaining subsidiaries against claims and liabilities relating to the past operation of our business.

We could have significant tax liabilities for periods during which Occidental operated our business.

For any tax periods (or portion thereof) in which Occidental owned at least 80% of the total voting power and value of our common stock, we and our subsidiaries were included in Occidental's consolidated group for federal income tax purposes. In addition, we or one or more of our subsidiaries may be included in the combined, consolidated or unitary tax returns of Occidental or one or more of its subsidiaries for state or local income tax purposes. Under the Tax Sharing Agreement, we will be responsible for any increase in Occidental's federal or state tax liability for any period in which we or any of our subsidiaries are combined or consolidated with Occidental if such increase results from audit adjustments attributable to our business. By virtue of Occidental's controlling ownership and the Tax Sharing Agreement, Occidental will effectively control all of our tax decisions in connection with any consolidated, combined or unitary income tax returns in which we (or any of our subsidiaries) are included. The Tax Sharing Agreement provides that Occidental will have sole authority to respond to and conduct all tax proceedings (including tax audits) relating to us, to prepare and file all consolidated, combined or unitary income tax returns in which we are included on our behalf (including the making of any tax elections). This arrangement may result in conflicts of interest between Occidental and us. For example, under the Tax Sharing Agreement, Occidental will be able to choose to contest, compromise or settle any adjustment or deficiency proposed by the relevant taxing authority in a manner that may be beneficial to Occidental and detrimental to us.

Moreover, notwithstanding the Tax Sharing Agreement, federal law provides that each member of a consolidated group is liable for the group's entire tax obligation. Thus, to the extent Occidental or other members of Occidental's consolidated group fail to make any federal income tax payments required by law, we could be liable for the shortfall with respect to periods in which we were a member of Occidental's consolidated group. Similar principles may apply for foreign, state or local income tax purposes where Occidental or its subsidiaries have filed combined, consolidated or unitary returns that include us.

We could have significant tax liabilities if the Spin-off, and certain transactions in preparation therefore, are not tax-free.

In certain circumstances, if the Spin-off is determined to be taxable for U.S. federal income tax purposes, we could incur significant liabilities under the Tax Sharing Agreement between us and Occidental. Occidental received a private letter ruling from the Internal Revenue Service (the IRS) to the effect that certain aspects of the transactions that were undertaken in preparation for, or in connection with, the Spin-off would not cause the distribution to be taxable to Occidental or its affiliates. Occidental also received opinions from tax counsel that (i) certain transactions that were undertaken in preparation for, or in connection with, the Spin-off would not be taxable to Occidental or its affiliates for federal income tax purposes and (ii) the Spin-off generally qualified as a tax-free transaction under Sections 355, 361 and/or 368(a)(1)(D) of the Code. The private letter ruling relied and the opinions relied on facts, assumptions, representations and undertakings from Occidental and us regarding the past and future conduct of the companies' respective businesses and other matters. If any of these facts, assumptions, representations, or undertakings are, or become, incorrect or not otherwise satisfied, Occidental may not be able to rely on the private letter ruling or the opinions of its tax advisor and could be subject to significant tax liabilities. In addition, an opinion of counsel is not binding upon the IRS, so, notwithstanding the opinions of Occidental's tax advisor, the IRS could conclude upon audit that the Spin-off is taxable in full or in part. The IRS may determine that the Spin-off is taxable for other reasons, including as a result of certain significant changes in the stock ownership of Occidental or us after the Spin-off.

Several members of our board of directors and management may have actual or potential conflicts of interest because of their ownership of shares of common stock of Occidental and the overlap of one member of our board of directors with the board of directors of Occidental.

Several members of our board of directors and management own common stock of Occidental or options to purchase common stock of Occidental, because of their current or prior relationships with Occidental, which create, or appear to create, potential conflicts of interest when our directors and executive officers are faced with decisions that could have different implications for Occidental and us. In addition, our board and the board of directors of Occidental have one member in common, which could create actual or potential conflicts of interest.

The Spin-off may expose us to potential liabilities arising out of federal and state fraudulent transfer or fraudulent conveyance laws and legal dividend requirements.

The Spin-off is subject to review under various federal and state fraudulent transfer or fraudulent conveyance laws. Under these laws, if a court in a lawsuit by an unpaid creditor or an entity vested with the power of such creditor (including a trustee or debtor-in-possession in a bankruptcy by us or Occidental or any of our respective subsidiaries) were to determine that Occidental or any of its subsidiaries did not receive fair consideration or reasonably equivalent value for distributing our common stock or taking other action as part of the Spin-off, or that we or any of our subsidiaries did not receive fair consideration or reasonably equivalent value for incurring indebtedness, including the new debt incurred by us in connection with the Spin-off, transferring assets or taking other action as part of the Spin-off and, at the time of such action, we, Occidental or any of our respective subsidiaries (i) was insolvent or would be rendered insolvent, (ii) had unreasonably small capital with which to carry on its business and all business in which it intended to engage or (iii) intended to incur, or believed it would incur, debts beyond its ability to repay such debts as they would mature, then such court could void the Spin-off as a constructive fraudulent transfer. The court could impose a number of different remedies, including voiding our liens and claims against Occidental, or providing Occidental with a claim for money damages against us in an amount equal to the difference between the consideration received by Occidental and the fair market value of our company at the time of the Spin-off.

The measures of insolvency for purposes of fraudulent transfer or fraudulent conveyance laws vary depending upon the governing law. Generally, an entity would be considered insolvent if:

- the sum of its debts, including contingent liabilities, were greater than the fair value of all its assets;
- the present fair saleable value of its assets were less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they become absolute and mature; or
- it could not pay its debts as they become due.

No assurance can be given as to what standard a court would apply to determine insolvency or that a court would determine that we, Occidental or any of our respective subsidiaries were solvent at the time of or after giving effect to the Spin-off, including the distribution of our common stock.

Under the Separation and Distribution Agreement between Occidental and us, from and after the Spin-off, we and Occidental each is responsible for the debts, liabilities and other obligations related to the business or businesses which it owns and operates following the consummation of the Spin-off, and we and Occidental and each assumed and retained certain liabilities for the operation of our respective businesses prior to the Spin-off and certain liabilities related to the Spin-off. Although we do not expect to be liable for any such obligations not expressly assumed by us pursuant to the Separation and Distribution Agreement, it is possible that a court would disregard the allocation agreed to between the parties, and require that we assume responsibility for obligations allocated to Occidental, particularly if Occidental were to refuse or were unable to pay or perform the subject allocated obligations.

The agreements between us and Occidental were not made on an arm's-length basis.

The agreements we entered into with Occidental in connection with the Spin-off, were negotiated while we were still a wholly-owned subsidiary of Occidental. Accordingly, during the period in which the terms of those agreements were negotiated, we did not have an independent board of directors or a management team independent of Occidental. As a result, the terms of those agreements may be unfavorable and may not reflect terms that would have resulted from arm's-length negotiations between unaffiliated third parties. The terms relate to, among other things, the allocation of assets, liabilities, rights and other obligations between Occidental and us.

ITEM 1B Unresolved Staff Comments

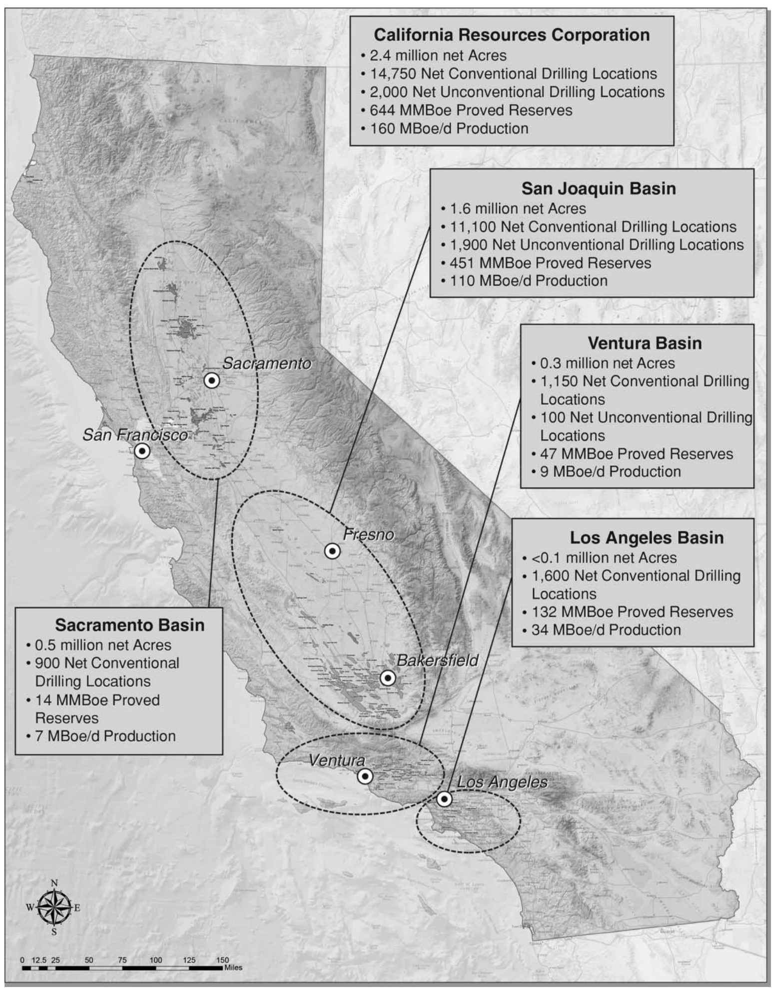
We have no unresolved SEC staff comments at December 31, 2015.

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 the third largest oil producing state in the nation. According to DOGGR, cumulative California production from all four basins in which we operate is 35 billion barrels of oil equivalent (BBoe), including approximately 19 BBoe in the San Joaquin basin, 10 BBoe in Los Angeles basin, 4 BBoe in Ventura basin and 10 trillion cubic feet (Tcf) of natural gas in 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. California imports more than 60% of its oil, mostly from foreign locations, and 90% of its natural gas. Because of limited crude transportation infrastructure from other parts of the country to California, the California market is generally isolated from the rest of the nation, which we believe have offered relatively favorable pricing compared to other U.S. regions for similar grades. Our operations include 137 fields with 9,067 gross active wellbores as of December 31, 2015. We believe we are the largest private oil and natural gas mineral acreage holder in California, with interests in approximately 2.4 million net acres. Approximately 60% of our total net mineral interest position is held in fee. 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 2015, we drilled 283 net development wells, of which more than 80% were producers and the rest were injectors and disposal wells. Our 2015 development drilling capital was approximately $130 million. Our 2015 total oil and gas capital of $370 million also included investments in facilities and compression expansion, workovers and exploration. In 2015 we produced 58 MMBoe. Our capital program, along with positive performance-related revisions of 45 MMBoe, added 81 MMBoe of proved reserves in 2015 representing a 140% organic reserves replacement ratio. For further information on reserves replacement ratio, see ''PV-10, Standardized Measure and Reserves Replacement Ratio'' section below.

San Joaquin Basin

We actively operate and are developing 45 fields in this inland basin in the southern part of California's central valley, which consists of conventional primary, IOR, EOR and unconventional project types with approximately 1.6 million net acres, approximately 62% of which we hold in fee. Approximately 70% of our estimated proved reserves as of December 31, 2015 and 69% of our average daily net production for the year ended December 31, 2015 came from the San Joaquin basin.

According to DOGGR, approximately 74% of California's daily oil production for 2014 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. Starting 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, covering approximately 50% of our San Joaquin acreage, will give us a competitive advantage in further exploring this basin. In 2015, we acquired 250 square miles of high-quality 3D seismic data to aid our future exploration and development of the asset.

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 over 1.9 BBoe to date. During the year ended December 31, 2015, we produced 60 MBoe/d on average from our Elk Hills properties, or approximately 38% of our total average daily production. Of our total Elk Hills production, 65% is liquids. We also operate efficient natural gas processing facilities, including a state-of-the-art cryogenic gas plant, with a combined capacity of over 540 MMcf/d. Additionally, we generate sufficient electricity to operate the field and sell excess power to the grid and to others through contractual agreements. A portion of our excess power is subject to a five-year contract with a local utility, which includes a minimum capacity payment, thereby providing us with rates that are generally better than we could receive from sales to the grid.

Our operations at Elk Hills possess a state-of-the-art central control facility and remote automation control on over 95% of our wells.

Los Angeles Basin

We actively operate and are developing 10 fields in this urban, coastal basin which consists of conventional primary, IOR, EOR and unconventional project types, approximately half of which we hold in fee. Approximately 20% of our estimated proved reserves as of December 31, 2015 and 21% of our average daily net production for the year ended December 31, 2015 were located in 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 as described further below.

Wilmington Oil Field

The Wilmington field located in Long Beach is the third largest field in the United States and has produced over 2.9 BBoe to date. During the year ended December 31, 2015, we produced approximately 35 MBoe/d gross on average, or 90% 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 2015 of approximately 28 MBoe/d equated to approximately 18% of our total average daily production. Most of our Wilmington production is covered under a set of contracts similar to production-sharing contracts under which we recover the total capital and operating costs and receive our share of profits. The field is developed by applying waterflood methods of oil recovery. 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 29 fields in this central California coastal basin which consists of primary conventional, IOR, EOR and unconventional project types. We currently hold approximately 0.3 million net acres in the Ventura basin, approximately 72% of which we hold in fee. Approximately 7% of our estimated proved reserves as of December 31, 2015 and approximately 6% of our average daily net production for the year ended December 31, 2015 were located in 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 play 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 acres in the Sacramento basin, approximately 36% of which we hold in fee. 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. Approximately 2% of our estimated proved reserves as of December 31, 2015 and approximately 4% of our average daily net production for the year ended December 31, 2015 were located in the Sacramento basin.

The Sacramento basin is a deep, thick sequence of sedimentary deposits within an elongated northwest-trending basin covering about 7.7 million acres. Exploration in the basin started 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 steamfloods or waterfloods 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 to approximately double those experienced under primary recovery methods. 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 in a low price environment. We use waterfloods extensively in the San Joaquin, Los Angeles and Ventura basins where they have allowed us to reduce production decline 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 oil 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 Potential

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 acres with unconventional potential and have identified over 2,300 gross (2,000 net) unconventional drilling locations on this acreage. As a result of focusing more on these reservoirs over the past few years, approximately 33% of our 2015 production was from unconventional reservoirs, an increase of approximately 125% since the acquisition of our Elk Hills field properties in 1998. As of December 31, 2015, we had proved reserves of 180 MMBoe associated with our unconventional properties, approximately 25% 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. The lower Monterey is believed to be the principal source rock within the Monterey.

In a higher price environment, we plan to apply the knowledge acquired from our successes in the upper Monterey to other unconventional reservoirs in the San Joaquin basin such as the Kreyenhagen and Moreno formations. The Kreyenhagen and Moreno formations are hydrocarbon source rocks that have generated oil and gas, and we believe they offer similar development opportunities to the upper Monterey and other resource play reservoirs onshore U.S. The lower Monterey 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 in the lower Monterey as well.

Exploration Program

We have a successful exploration program in both conventional and unconventional plays under which discoveries are quickly developed into producing fields. We believe our experienced technical staff, proprietary geological models, leading acreage position and extensive 3D seismic library give us a strong competitive advantage. Our interpretation of this seismic data, covering a large portion of our prospective acreage, and our extensive knowledge of California geology and producing fields, has resulted in a large inventory of low-risk exploratory projects in proven play trends. As of December 31, 2015, our drilling inventory included 9,800 gross (4,800 net) exploration drilling locations in proven reservoirs, the majority of which are located near existing producing fields. Additionally, we have identified 6,400 gross (5,300 net) prospective resource drilling locations in the lower Monterey, Kreyenhagen and Moreno unconventional reservoirs.

In 2015, we completed three conventional exploration projects all of which successfully encountered hydrocarbons. Within an existing producing field, one of our exploration wells, which was drilled in late 2014, encountered multiple, stacked conventional oil reservoirs. Over the course of 2015, we conducted operations to isolate and individually test two of the reservoir intervals with significant behind pipe pay remaining uphole. In those flow tests, the deepest reservoir interval flowed at peak daily rates of approximately 200 barrels of oil per day and was flowed on pump for six months. The second reservoir interval flowed naturally at peak daily rates in excess of 750 barrels of oil per day and 1.5 MMcf of natural gas per day. We believe there may be multiple analogous prospects in this underexplored play trend that could extend for over 20 miles.

Within the San Joaquin basin we drilled three exploration wells that successfully demonstrated and delineated the presence of a heavy oil accumulation. In the Sacramento Basin, we drilled one well to test a 50 square mile four-way closure that was mapped on our proprietary 2D seismic data. This conventional exploration well encountered multiple stacked gas bearing reservoirs.

We continue to develop our understanding and knowledge of the significant prospective resources in the exploration shale reservoirs. In 2015, we completed the acquisition of approximately 200 square miles of proprietary 3D seismic data around the Kettleman North Dome field that will aid with reservoir characterization and fracture analysis. In addition, we undertook reservoir analyses incorporating proprietary log and core data to further advance our understanding of exploration shale reservoirs. We completed four workovers in existing wellbores and drilled one new well undertaking zonal completions to assess the expected performance of individual zones of interest and identify landing zones for future horizontal development.

Our Reserves and Production Information

Reserves Data

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

Reserves Presentation

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, unless prices were defined by contractual arrangements. Oil, NGLs and natural gas prices used for this purpose were based on posted benchmark prices and adjusted for price differentials including gravity, quality and transportation costs. For the 2015 disclosures, the calculated average Brent oil price was $55.57 per barrel and the average NYMEX gas price was $2.59 per Mcf. The average realized prices used for the 2015 disclosures were $50.54 per barrel for oil, $20.07 per barrel for NGLs and $2.55 per Mcf for natural gas.

During the course of 2015, we experienced significant and extended price declines from 2014, which impacted the quantity of reserves we reported as of December 31, 2015. The unweighted arithmetic average first-day-of-the-month price for Brent oil decreased from $101.30 per barrel for 2014 to $55.57 for 2015. As a result, we experienced negative price related revisions to our proved reserves at December 31, 2015. Generally, lower prices adversely impact the quantity of our reserves as those reserves may no longer meet the economic producibility criteria under the rules or may be removed due to a lower amount of capital available to develop these projects within the SEC-mandated five-year limit. However, our production-sharing contracts in Long Beach tend to partially offset these effects because our share of production and reserves from these contracts increases as prices decline. Further, during the course of the year we implemented significant cost reduction and efficiency steps, which reduced our total field operating costs by over 13% on a per Boe basis, and drilling costs by approximately 10%. These cost reductions, as well as efficiency efforts, offset a portion of the price-related loss of reserves quantities as some of the barrels that would become uneconomic in later years remain economic, a portion of the proved undeveloped reserves that would otherwise be removed from the reserves quantities become economic and we expect to drill more wells with the same amount of capital. We expect further costs savings to be achieved in 2016 but cannot assure that our expectations will be realized.

During the latter part of 2015, and into early 2016, oil prices continued to decline. If prices remain at or near current levels for the rest of 2016, or if they decline further, the prices used to determine our year-end 2016 reserves estimates could be significantly lower than those used for year-end 2015. Under such circumstances, we may experience further negative price-related revisions to our proved reserves at year-end 2016. If the SEC prices for the December 31, 2015 reserves determination were about $10 lower than those actually used, we believe our reserves quantities may have been lower by less than 15%. This estimate does not reflect the effect of further cost savings that we expect to achieve in 2016. If the SEC prices for the December 31, 2015 reserves determination were about $10 higher than those actually used, we believe our reserves quantities may have been higher by over 10%.

The following tables summarize our estimated proved reserves and related PV-10 and Standardized Measure at December 31, 2015. Reserves are stated net of applicable royalties. Estimated reserves include our economic interests under arrangements similar to production-sharing contracts relating to the Wilmington field in Long Beach.

	As of December 31, 2015				
	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Proved developed reserves:					
Oil (MMBbl)	205	103	30	—	338
NGLs (MMBbl)	45	—	2	—	47
Natural Gas (Bcf)	456	9	24	86	575
Total (MMBoe)(1)(2)	326	105	36	14	481
Proved undeveloped reserves:					
Oil (MMBbl)	92	27	9	—	128
NGLs (MMBbl)	11	—	1	—	12
Natural Gas (Bcf)	135	2	3	—	140
Total (MMBoe)(2)	125	27	11	—	163
Total proved reserves:					
Oil (MMBbl)	297	130	39	—	466
NGLs (MMBbl)	56	—	3	—	59
Natural Gas (Bcf)	591	11	27	86	715
Total (MMBoe)(2)	451	132	47	14	644

(1) Approximately 16% of proved developed oil reserves, 9% of proved developed NGLs reserves, 14% of proved developed natural gas reserves and 15% of total proved developed reserves are non-producing.

(2) 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. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2015, the average prices of Brent oil and NYMEX natural gas were $53.64 per Bbl and $2.75 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 20 to 1.

PV-10, Standardized Measure and Reserves Replacement Ratio

	At December 31, 2015
	($ in millions)
PV-10 of proved reserves[1]	$ 5,059
Present value of future income taxes discounted at 10%	(1,035)
Standardized measure of discounted future net cash flows	$ 4,024
Organic reserves replacement ratio[2]	140%

(1) PV-10 is a non-GAAP financial measure and represents the year-end present value of estimated future cash inflows from proved oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows and using SEC prescribed pricing assumptions for the period. PV-10 differs from Standardized Measure because Standardized Measure includes the effects of future income taxes on future net cash flows. Neither PV-10 nor Standardized Measure should be construed as the fair value of our oil and natural gas reserves. PV-10 and Standardized Measure are used by the industry and by our management as an asset value measure to compare against our past reserves bases and the reserves bases of other business entities because the pricing, cost environment and discount assumptions are prescribed by the SEC and are comparable. PV-10 further facilitates the comparisons to other companies as it is not dependent on the tax paying status of the entity.

(2) The organic reserves replacement ratio is calculated for a specified period using the proved oil-equivalent additions from extensions and discoveries, improved recovery and performance-related provisions, divided by oil-equivalent production. Approximately 48% of the additions for 2015 were proved undeveloped. There is no guarantee that historical sources of reserves additions will continue as many factors fully or partially outside management's control, including commodity prices, availability of capital and the underlying geology affect reserves additions. Management uses this measure to gauge the results of its capital allocation. The measure is limited in that reserves may be added and produced based on costs incurred in separate periods and other oil and gas producers may use different replacement ratios affecting comparability.

Proved Reserves Additions

We added 36 MMBoe resulting from our capital program, 45 MMBoe due to positive performance revisions and 6 MMBoe as a result of property acquisitions. These additions were offset by 153 MMBoe of negative revisions for volumes that became uneconomic due to lower prices. The price revisions incorporated the positive effect of lower operating costs also caused by the lower commodity price environment. In a higher price environment, many of the volumes that became uneconomic this year could again become economic and be added back to the reserves base. The components of the changes to our proved reserves during the year ended December 31, 2015 were as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Extensions and discoveries:					
Oil (MMBbl)	8	12	5	—	25
NGLs (MMBbl)	2	—	—	—	2
Natural Gas (Bcf)	27	1	—	6	34
Total (MMBoe)	15	12	5	1	33
Improved recovery:					
Oil (MMBbl)	3	—	—	—	3
NGLs (MMBbl)	—	—	—	—	—
Natural Gas (Bcf)	—	—	—	—	—
Total (MMBoe)	3	—	—	—	3
Total reserves additions from capital program	18	12	5	1	36
Revisions related to performance:					
Oil (MMBbl)	5	50	(1)	—	54
NGLs (MMBbl)	(20)	—	—	—	(20)
Natural Gas (Bcf)	42	3	1	19	65
Total (MMBoe)	(8)	51	(1)	3	45
Revisions related to price changes:					
Oil (MMBbl)	(40)	(83)	(11)	—	(134)
NGLs (MMBbl)	(3)	—	—	—	(3)
Natural Gas (Bcf)	(44)	(8)	(7)	(39)	(98)
Total (MMBoe)	(50)	(85)	(12)	(6)	(153)
Acquisitions:					
Oil (MMBbl)	4	—	—	—	4
NGLs (MMBbl)	1	—	—	—	1
Natural Gas (Bcf)	8	—	—	—	8
Total (MMBoe)	6	—	—	—	6

Our ability to add reserves, other than through acquisitions, 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.

Extensions and Discoveries

We added 33 MMBoe of proved reserves from extensions and discoveries, which generally result from exploration, exploitation and development programs. The extensions and discovery additions were associated with the continued successful drilling primarily in San Joaquin, Los Angeles, and Ventura basins.

Improved Recovery

In 2015, we added proved reserves of 3 MMBoe from improved recovery through proven IOR and EOR methods. The improved recovery additions in 2015 were associated with the continued development of thermal and water flood properties in the San Joaquin basin. The types of conventional IOR and EOR development methods we use can be applied through existing wells, though additional drilling is frequently required to fully optimize the development configuration.

Revisions of Previous Estimates

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 geologic, production decline or operating performance data. In 2015, our positive performance related revisions of 45 MMBoe resulted primarily from better than expected reservoir performance, combined with lower development capital than previously estimated. These positive revisions came from the San Joaquin and Los Angeles basins.

Revisions related to price changes—In addition, product price changes affect 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 Long Beach operations because less oil is required to recover costs. Conversely, when prices drop, we experience the opposite effects. Total net negative price revisions in 2015 were 153 MMBoe. The price revisions incorporated the positive effect of lower operating costs also caused by the lower commodity price environment.

Proved Undeveloped Reserves

In 2015, we had proved undeveloped reserves additions of 25 MMBoe from extensions and discoveries and 3 MMBoe from improved recovery, primarily in the San Joaquin and Los Angeles basins and 11 MMBoe from performance-related revisions, offset by 69 MMBoe of negative revisions due to lower prices. We transferred 24 MMBoe of proved undeveloped reserves to the proved developed category as a result of the 2015 development program, almost all of which was in the San Joaquin basin. As a result, we converted approximately 16% of our beginning-of-year proved undeveloped reserves, adjusted for price changes, to proved developed reserves during the year, investing approximately $90 million of drilling capital. The total changes to our proved undeveloped reserves during the year ended December 31, 2015 were as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Improved recovery:					
Oil (MMBbl)	3	—	—	—	3
NGLs (MMBbl)	—	—	—	—	—
Natural Gas (Bcf)	—	—	—	—	—
Total (MMBoe)	3	—	—	—	3
Extensions and discoveries:					
Oil (MMBbl)	7	9	3	—	19
NGLs (MMBbl)	2	—	—	—	2
Natural Gas (Bcf)	19	1	4	2	26
Total (MMBoe)	12	9	4	—	25
Revisions related to performance:					
Oil (MMBbl)	3	20	(4)	—	19
NGLs (MMBbl)	(8)	—	—	—	(8)
Natural Gas (Bcf)	2	1	(2)	—	1
Total (MMBoe)	(5)	20	(4)	—	11
Revisions related to price changes:					
Oil (MMBbl)	(12)	(39)	(4)	—	(55)
NGLs (MMBbl)	(3)	—	—	—	(3)
Natural Gas (Bcf)	(44)	(5)	(8)	(8)	(65)
Total (MMBoe)	(22)	(40)	(6)	(1)	(69)
Acquisitions:					
Oil (MMBbl)	1	—	—	—	1
NGLs (MMBbl)	—	—	—	—	—
Natural Gas (Bcf)	1	—	—	—	1
Total (MMBoe)	1	—	—	—	1
Transfers to proved developed reserves:					
Oil (MMBbl)	(21)	(2)	—	—	(23)
NGLs (MMBbl)	—	—	—	—	—
Natural Gas (Bcf)	(6)	—	—	—	(6)
Total (MMBoe)	(22)	(2)	—	—	(24)

Our year-end development plans and associated proved undeveloped reserves are consistent with SEC guidelines for development within five years. Global oversupply continues to suppress oil and gas prices significantly. Prolonged or further declines in commodity prices could require us to reduce expected capital spending over the next five years, potentially impacting either the quantity or the development timing of proved undeveloped reserves.

Reserves Evaluation and Review Process

Our estimates of proved reserves and associated future net cash flows as of December 31, 2015 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 used 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 that 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 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 15 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 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 2015. 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 2015 reserves estimates for fields that comprise at least 80% of our total proved reserves. Previously, Ryder Scott conducted process reviews of our properties on behalf of our former parent. The primary technical engineer responsible for our audit has 25 years of petroleum engineering experience, 20 of which have been in the estimation and evaluation of reserves. He serves on the Ryder Scott Board of Directors, is an advising member of SPE's Oil and Gas Reserves Committee and a registered Professional Engineer in the state of Texas.

The 2015 reserves audit included a detailed review of 80% 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. 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, 2015. Ryder Scott's report is attached as an exhibit to this Form 10-K.

Determination of Identified Drilling Locations

Proven Drilling Locations

Based on our reserves report as of December 31, 2015, we have approximately 2,600 gross (2,250 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 they have been evaluated technically and are deemed to be drillable within a five-year time frame. As a result of rigorous technical evaluation of geologic and engineering data, it can be estimated 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 11,100 gross (9,700 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

Our portfolio of prospective drilling locations contains approximately 9,800 gross (4,800 net) unrisked exploration drilling locations in proven 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 adjacent fields.

Prospective Resource Drilling Locations

In addition, 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 contain 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. Prospective resource drilling locations were 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 (i.e., 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 and our prospective resource 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, 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 ''Risk Factors—Risks Related to Our Business and Industry.''

With our limited capital budget for 2016, including no exploration, many of the identified drilling locations may be uneconomic at current prices. The table below sets forth our total gross identified drilling locations as of December 31, 2015, excluding our prospective drilling locations from new resource plays.

	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	200	—	10,300	—
Steamflood	1,150	300	3,700	1,000
Waterflood	150	50	1,200	750
Unconventional	250	—	1,850	350
San Joaquin Basin subtotal	1,750	350	17,050	2,100
Los Angeles Basin				
Primary Conventional	—	—	50	—
Steamflood	—	—	—	—
Waterflood	250	100	1,200	400
Unconventional	—	—	—	—
Los Angeles Basin subtotal	250	100	1,250	400
Ventura Basin				
Primary Conventional	50	—	950	—
Steamflood	—	—	250	—
Waterflood	50	50	100	100
Unconventional	—	—	100	—
Ventura Basin subtotal	100	50	1,400	100
Sacramento Basin				
Primary Conventional	1	—	1,150	—
Sacramento Basin subtotal	1	—	1,150	—
Total Identified Drilling Locations	2,101	500	20,850	2,600

Production, Price and Cost History

Oil, NGLs and natural gas are commodities; therefore, 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 and refining disruptions, currency exchange rates, worldwide drilling and exploration activities, the effects of conservation, weather, geophysical and technical limitations, refining and processing disruptions, transportation bottlenecks and other matters affecting the supply and demand dynamics for our products, technological advances and regional market conditions; transportation capacity and costs in producing areas; and the effect of changes in these variables on market perceptions. Given the volatile oil price environment, as well as our leverage, we began a hedging program shortly after the Spin-off to protect our cash flow and capital investment program and improve our ability to comply with our credit facility covenants in case of further price deterioration.

Fixed and Variable Costs

Our total production costs consist of variable costs that tend to vary depending on production levels, and fixed costs that 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 less than 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. If we see growth in a field we increase capacities, and similarly if a field is reaching the end of its economic life we would manage the costs while it remains economically viable to produce.

The following table sets forth information regarding production, realized and benchmark prices, and costs for oil and gas producing activities for the years ended December 31, 2015, 2014 and 2013. For additional information on price calculations, see information set forth in ''Management's Discussion and Analysis of Financial Condition and Results of Operations.''

	Year Ended December 31,		
	2015	2014	2013
Production Data:			
Oil (MBbl/d)	104	99	90
NGLs (MBbl/d)	18	19	20
Natural gas (MMcf/d)	229	246	260
Average daily combined production (MBoe/d)	160	159	154
Total combined production (MMBoe)	58	58	56
Average realized prices:			
Oil prices with hedge ($/Bbl)	$ 49.19	$ 92.30	$ 104.16
Oil prices without hedge ($/Bbl)	$ 47.15	$ 92.30	$ 104.16
NGLs prices ($/Bbl)	$ 19.62	$ 47.84	$ 50.43
Natural gas prices ($/Mcf)	$ 2.66	$ 4.39	$ 3.73
Average Benchmark prices:			
Brent oil ($/Bbl)	$ 53.64	$ 99.51	$ 108.76
WTI oil ($/Bbl)	$ 48.80	$ 93.00	$ 97.97
NYMEX gas ($/Mcf)	$ 2.75	$ 4.34	$ 3.66
Average costs per Boe:[(a)]			
Production costs	$ 16.30	$ 18.23	$ 17.56
General and administrative expense, as adjusted[(b)]	$ 1.00	$ 2.31	$ 2.35
Other operating expenses, as adjusted[(c)]	$ 0.36	$ 0.55	$ 0.60
Depreciation, depletion and amortization	$ 16.72	$ 20.40	$ 20.11
Taxes other than on income	$ 2.67	$ 3.50	$ 3.05

(a) For 2015 and 2014, the amount excludes asset impairment charges of $4.9 billion and $3.4 billion, respectively.

(b) For 2015, the amount excludes unusual and infrequent costs of $0.31 per Boe related to early retirement and severance costs. For 2014, the amount excludes unusual and infrequent costs of $0.10 per Boe related to Spin-off and transition related costs.

(c) For 2015, the amount excludes unusual and infrequent costs related to the write-down of certain assets and rig termination charges of $1.42 per Boe. For 2014, the amount excludes unusual and infrequent costs related to rig termination charges and Spin-off and transition related costs of $0.97 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, 2015, 2014 and 2013:

	Elk Hills			Wilmington		
	2015	2014	2013	2015	2014	2013
Production data:						
Oil (MBbl/d)	24	25	26	28	25	22
NGLs (MBbl/d)	15	16	18	—	—	—
Natural gas (MMcf/d)[(a)]	123	136	145	1	—	—
Average realized prices:[(b)]						
Oil (MBbl/d)	$ 52.78	$ 97.27	$ 106.32	$ 45.50	$ 90.37	$ 103.29
NGLs (MBbl/d)	$ 20.12	$ 48.68	$ 49.62	$ —	$ —	$ —
Natural gas (MMcf/d)[(a)]	$ 2.67	$ 4.47	$ 3.67	$ 2.05	$ —	$ —
Production costs per Boe	$ 11.11	$ 14.31	$ 12.34	$ 21.87	$ 28.98	$ 31.56

(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. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2015, the average prices of Brent oil and NYMEX natural gas were $53.64 per Bbl and $2.75 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 20 to 1.

(b) Excludes the effect of hedges.

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

	Total Proved Reserves		Average Net Daily Production(MBoe/d)
	MMBoe	Oil (%)	Year ended December 31, 2015
San Joaquin Basin			
Primary Conventional	62	69%	19
Waterfloods	60	78%	8
Steamfloods[(a)]	149	100%	31
Unconventional	180	33%	52
San Joaquin Basin subtotal	451	66%	110
Los Angeles Basin			
Primary Conventional	1	100%	1
Waterfloods	131	98%	33
Steamfloods	—	—%	—
Unconventional	—	—%	—
Los Angeles Basin subtotal	132	98%	34
Ventura Basin			
Primary Conventional	16	75%	5
Waterfloods	31	84%	4
Steamfloods	—	—%	—
Unconventional	—	—%	—
Ventura Basin subtotal	47	83%	9
Sacramento Basin			
Primary Conventional	14	—%	7
Sacramento Basin subtotal	14	—%	7
Total	644	72%	160

(a) Includes reserves and production from gas injection of 35% and 9%, respectively.

Productive Wells

As of December 31, 2015, we had a total of 9,067 gross (8,123 net) producing wells, approximately 91% of which were oil wells. Our average working interest in our producing wells is approximately 90%. Many of our oil wells produce associated natural gas and some of our natural gas wells also produce condensate and NGLs.

The following table sets forth our productive oil and natural gas wells (both producing and capable of production) as of December 31, 2015, excluding wells that have been idle for more than five years:

	San Joaquin Basin		Los Angeles Basin		Ventura Basin		Sacramento Basin		Total	
Oil										
Gross[(a)(b)]	8,124	(963)	1,752	(56)	1,099	(61)	—	—	10,975	(1,080)
Net[(a)(c)]	7,222	(742)	1,654	(51)	1,091	(59)	—	—	9,967	(852)
Natural Gas										
Gross[(a)(b)]	189	(92)	8	—	—	—	1,273	(58)	1,470	(150)
Net[(a)(c)]	161	(78)	8	—	—	—	1,183	(56)	1,352	(134)

(a) Numbers in parentheses indicate the number of wells with multiple completions.
(b) The total number of wells in which interests are owned.
(c) Includes fractional interests.

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, 2015, of which approximately 60% is held in fee. Of the remaining portion that is leased, approximately 40% was held by production at December 31, 2015.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in thousands)		
Developed[(a)]					
Gross[(b)]	436	25	71	268	800
Net[(c)]	398	20	69	249	736
Undeveloped[(d)]					
Gross[(b)]	1,418	18	231	373	2,040
Net[(c)]	1,159	14	193	287	1,653

(a) Acres spaced or assigned to productive wells.
(b) Total acres in which we hold an interest.
(c) Sum of fractional interests owned 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 business basis 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 19% of our total net undeveloped acreage at December 31, 2015 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.

Participation in Exploratory and Development Wells Being Drilled

The following table sets forth our participation in exploratory and development wells being drilled as of December 31, 2015.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Exploratory and development wells					
Gross	10	1	—	—	11
Net	10	1	—	—	11

At December 31, 2015, we were producing from eight steamfloods and 42 waterfloods. We currently do not have any ongoing material capital investments in these projects. All of the significant steamflood projects were located in the San Joaquin basin. Twenty-five waterflood projects were located in the Los Angeles basin and 17 in the San Joaquin basin.

Drilling Activity

The following table describes our drilling activity for the periods indicated. 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. 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.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
2015					
Oil					
Exploratory	3.0	—	—	—	3.0
Development	254.0	29.1	—	—	283.1
Natural Gas					
Exploratory	—	—	—	—	—
Development	—	—	—	—	—
Dry					
Exploratory	—	—	—	—	—
Development	—	—	—	—	—
2014					
Oil					
Exploratory	2.0	—	1.7	—	3.7
Development	775.2	170.2	20.3	—	965.7
Natural Gas					
Exploratory	—	—	—	—	—
Development	—	—	—	3.0	3.0
Dry					
Exploratory	8.0	—	2.0	1.0	11.0
Development	2.3	0.9	—	—	3.2
2013					
Oil					
Exploratory	2.0	—	—	—	2.0
Development	543.1	125.7	18.8	—	687.6
Natural Gas					
Exploratory	—	—	—	—	—
Development	—	—	—	7.7	7.7
Dry					
Exploratory	5.0	—	1.0	1.0	7.0
Development	2.5	0.9	—	—	3.4

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, 2015, we had 30- to 90-day oil delivery commitments ranging from 21 MBbls/d to 41 MBbls/d, gas contracts for 2 Bcf of natural gas under 30-day contracts and 2 Bcf of natural gas under 90-day contracts, and NGL commitments for 1 MMBbls of NGLs through March 2016. These are index-based contracts with prices set at the time of delivery. We have significantly more production capacity than the amounts committed and have the ability to secure additional volumes in case of a shortfall. None of the commitments in any given year is expected to have a material impact on our financial statements.

Our Infrastructure

We own infrastructure that is integral to and significantly complements our operations. Our Elk Hills cryogenic gas plant has a capacity of 200 MMcf/d of wellhead gas bringing our total Elk Hills processing capacity to over 540 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 certain North American NGLs markets. In addition, we have truck rack facilities coupled with a battery of pressurized storage tanks at our Elk Hills natural gas processing facility for NGL sales to third parties.

We generate all of our electricity needs at our Elk Hills operations, which utilizes approximately a third of our wholly-owned 550 megawatt combined-cycle power plant located adjacent to our Elk Hills processing facilities, and sell the excess. We also operate a 46 megawatt cogeneration facility at Elk Hills that provides resource diversity and additional reliability to support field operations. Within our Long Beach operations, we operate a 45 megawatt power generating facility that provides over 40% of the Long Beach operation's electricity requirements, reducing operating costs. These power facilities are integrated with our operations to improve their reliability and performance.

We own an extensive network of over 20,000 miles of oil and gas gathering lines. These gathering lines are dedicated almost entirely to collect our oil and gas production and are in close proximity to field specific facilities such as tank settings or central processing sites. These lines provide a variety of services, including connecting our producing wells to gathering networks, natural gas collection and compression systems, lines for water treating and injection services, steam supply for our thermal properties, and water lines that deliver treated water for agriculture. Nearly all of our oil is then transported through third party pipelines with flexibility to ship to various parties. In addition, virtually all of our natural gas production interconnects 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.

ITEM 3 Legal Proceedings

For information regarding legal proceedings, see the information under the caption, ''Lawsuits, Claims, Commitments and Contingencies'' in the MD&A section of this report and in Note 7 of our Financial Statements.

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 29, 2016
William E. Albrecht	Executive Chairman since 2014; Occidental Vice President 2008 to 2014; Oxy Oil & Gas, Americas President 2012 to 2014; Oxy Oil & Gas, USA President 2008 to 2012.	64
Todd A. Stevens	President, Chief Executive Officer and Director since 2014; Occidental Vice President—Corporate Development 2012 to 2014; Oxy Oil & Gas Vice President—California Operations 2008 to 2012; Occidental Vice President—Acquisitions and Corporate Finance 2004 to 2012.	49
Marshall D. Smith	Senior Executive Vice President and Chief Financial Officer since 2014; Ultra Petroleum Corp. Chief Financial Officer 2005 to 2014; Ultra Petroleum Corp. Senior Vice President 2011 to 2014.	56
Robert A. Barnes	Executive Vice President—Northern Operations since 2014; Occidental of Elk Hills President and General Manager 2012 to 2014; Oxy Permian CO_2 Operations Manager 2011 to 2012, Occidental Argentina Deputy General Manager and Senior Vice President, Operations 2010 to 2011; Occidental Argentina Vice President, Operations 2007 to 2010.	59
Frank E. Komin	Executive Vice President—Southern Operations since 2014; OXY Long Beach President and General Manager 2001 to 2014; Oxy THUMS President and General Manager 2001 to 2009.	61
Shawn M. Kerns	Executive Vice President—Corporate Development since 2014; 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.	45
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.	53
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.	51
Charles F. Weiss	Executive Vice President—Public Affairs since 2014; Occidental Vice President, Health, Environment and Safety 2007 to 2014.	52
Darren Williams	Executive Vice President—Exploration since 2014; 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.	44

Mr. Albrecht will transition from Executive Chairman to a non-executive Chairman role effective with the May 4, 2016 meeting of the Board of Directors. In addition, Mr. Komin will retire during 2016 and Mr. Barnes will assume his responsibilities with respect to our Southern Operations.

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. 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			
	2015		2014	
	High	Low	High	Low
First Quarter	$ 7.87	$ 3.75	N/A	N/A
Second Quarter	$ 9.87	$ 6.00	N/A	N/A
Third Quarter	$ 6.05	$ 2.26	N/A	N/A
Fourth Quarter[a]	$ 5.15	$ 1.76	$ 7.37	$ 5.29

(a) For 2014, this period covers the month ended December 31, 2014.

Holders of Record

CRC common stock was held by approximately 25,840 stockholders of record at December 31, 2015, and by approximately 175,000 additional stockholders whose shares were held for them in street name or nominee accounts.

Dividend Policy

In 2015, we paid quarterly dividends of $0.01 per share for the first three quarters of the year. No dividends were paid in 2014.

In November 2015, our Board of Directors suspended the payment of our quarterly dividend of $0.01 per share. This decision is consistent with the Company's broader initiatives to cut costs and reduce overall debt levels. The payment of future cash 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 the ''Liquidity and Capital Resources—Credit Facilities'' section below 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 sole stockholder prior to the Spin-off. A description of the plans can be found in Note 11 of our Financial Statements. 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 30 million, of which approximately 8.7 million had been issued through December 31, 2015. If approved at our 2016 Annual Meeting, the number of shares authorized for grant under such plans would increase to 57 million.

The following is a summary of the securities available for issuance under such plans:

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))
12,621,340[3]	\$7.02[1]	9,772,308[2][3]

(1) Exercise price applies only to approximately 11.5 million options included in column (a) and not to any other awards.

(2) Includes 2.9 million shares subject to rights to purchase common stock under our 2014 Employee Stock Purchase Plan (ESPP) at 85% of the lower of the market price at (i) the start of a quarter and (ii) the end of a quarter. Shares first became subject to purchase at the end of the first quarter of 2015. The number of securities remaining available for future issuance under our ESPP, as reported above, excludes 568,457 shares of our common stock which were issued during 2015 in settlement of ESPP option exercises for the final purchase period, which concluded on December 31, 2015.

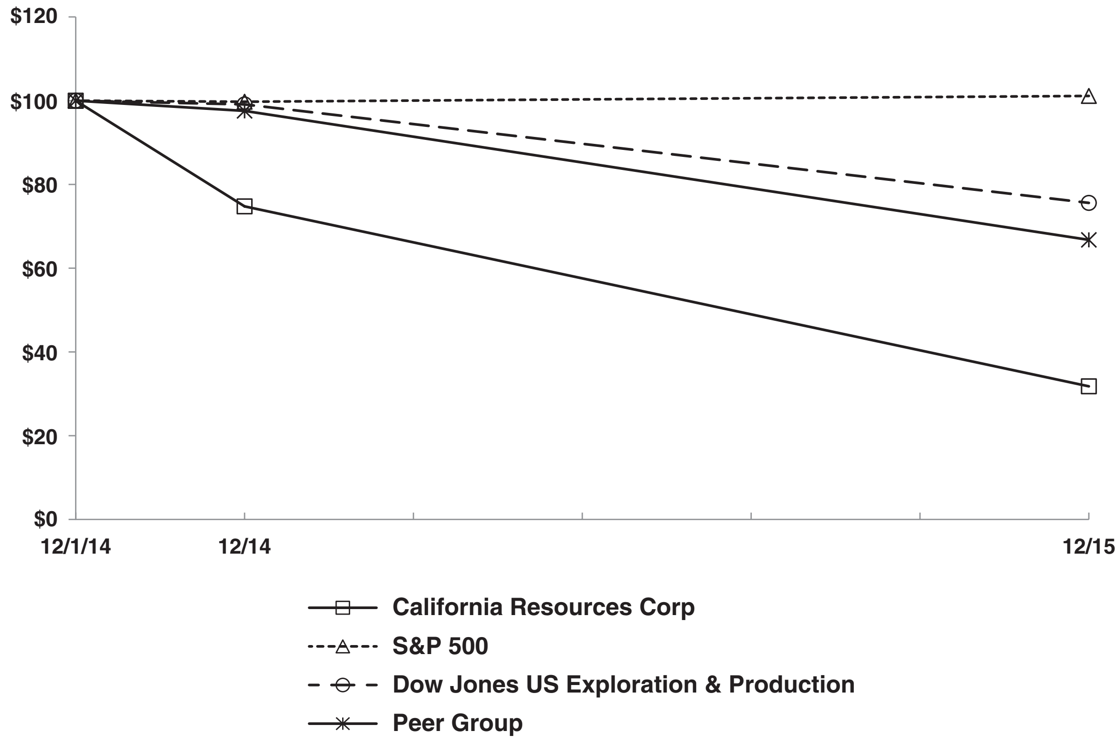
(3) Does not include awards issued in 2015 (7.2 million shares based on maximum payout or 4.5 million shares based on target payout) currently treated as cash-settled awards that are intended to be share-settled awards subject to shareholder approval of our 2014 Long-Term Incentive Plan at our annual meeting in May 2016.

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 (with reinvestment of all dividends). The graph assumes $100 was invested in our common stock and in each index on December 1, 2014, the date our common stock began trading on the NYSE, and its relative performance is tracked through December 31, 2015. The returns shown are based on historical results and are not intended to suggest future performance.

COMPARISON OF 1 YEAR CUMULATIVE TOTAL RETURN*

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



*$100 invested on 12/1/14 in stock or 11/30/14 in index, including reinvestment of dividends.
Fisal year ending December 31.

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 the California business of Occidental. All financial information presented after the Spin-off represents CRC's consolidated results of operations, financial position and cash flows. Accordingly:

- The selected statement of operations and cash flows data for the year ended December 31, 2015 consists of the stand-alone consolidated results of California Resources Corporation 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 data for the years ended December 31, 2013, 2012 and 2011 consists entirely of the combined results of the California business.
- The selected balance sheet data at December 31, 2015 and 2014 consists of the consolidated balances of California Resources Corporation, while the selected balance sheet data at December 31, 2013, 2012 and 2011 consists of the combined balances of the California business.

	Year Ended December 31,				
	2015	2014	2013	2012	2011
			(in millions)		
Statement of Operations Data					
Revenues	$ 2,403	$ 4,173	$ 4,284	$ 4,073	$ 3,934
Income / (loss) before income taxes	$ (5,476)	$ (2,421)	$ 1,447	$ 1,181	$ 1,641
Net income / (loss)	$ (3,554)	$ (1,434)	$ 869	$ 699	$ 971
Per common share					
Basic	$ (9.27)	$ (3.75)	$ 2.24	$ 1.80	$ 2.50
Diluted	$ (9.27)	$ (3.75)	$ 2.24	$ 1.80	$ 2.50
Statement of Cash Flows Data					
Net cash provided by operating activities	$ 403	$ 2,371	$ 2,476	$ 2,223	$ 2,456
Capital investments	$ (401)	$ (2,089)	$ (1,669)	$ (2,331)	$ (2,164)
Acquisitions	$ (141)	$ (288)	$ (48)	$ (427)	$ (1,405)
Borrowings, net of costs	$ 379	$ 6,290	$ —	$ —	$ —
Spin-off related dividends to Occidental	$ —	$ (6,000)	$ —	$ —	$ —
(Distributions to) contributions from Occidental, net	$ —	$ (335)	$ (763)	$ 532	$ 1,106
Dividends per Common Share	$ 0.03	$ —	$ —	$ —	$ —

	As of December 31,				
	2015	2014	2013	2012	2011
			(in millions)		
Balance Sheet Data					
Total current assets	$ 497	$ 701	$ 254	$ 245	$ 195
Property, plant and equipment, net	$ 6,312	$ 11,685	$ 14,008	$ 13,499	$ 11,778
Total assets	$ 7,053	$ 12,429	$ 14,297	$ 13,764	$ 11,989
Total current liabilities	$ 605	$ 922	$ 689	$ 551	$ 664
Long-term debt—principal amount	$ 6,043	$ 6,360	$ —	$ —	$ —
Deferred gain and issuance costs, net	$ 491	$ (68)	$ —	$ —	$ —
Other long-term liabilities	$ 830	$ 549	$ 497	$ 511	$ 454
Equity	$ (916)	$ 2,611	$ 9,989	$ 9,860	$ 8,624

The selected financial data presented above should be read in conjunction with ''Management's Discussion and Analysis of Financial Condition and Results of Operations'' and the consolidated and combined 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

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 from Occidental on November 30, 2014 (the ''Spin-off''), and (3) all references to ''Occidental'' refer to Occidental Petroleum Corporation, our former parent, and its subsidiaries.

The Separation and Spin-off

We are an independent oil and natural gas exploration and production company operating properties exclusively within the State of California. 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 the Spin-off. On November 30, 2014, Occidental distributed shares of our common stock on a pro rata basis to Occidental stockholders and we became an independent, publicly traded company. Occidental retained approximately 18.5% of our outstanding shares of common stock which it has stated it intends to divest on March 24, 2016.

Basis of Presentation and Certain Factors Affecting Comparability

Until the Spin-off, the accompanying financial statements were derived from the consolidated financial statements and accounting records of Occidental and were presented on a combined basis for the pre-Spin-off periods. These financial statements reflect the historical results of operations, financial position and cash flows of the California business. All financial information presented after the Spin-off consists of the stand-alone consolidated results of operations, financial position and cash flows of CRC. 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.

The statements of operations for periods prior to the Spin-off include expense allocations for certain corporate functions and centrally-located activities historically performed by Occidental. These functions include executive oversight, accounting, treasury, tax, financial reporting, finance, internal audit, legal, risk management, information technology, government relations, public relations, investor relations, human resources, procurement, engineering, drilling, exploration, marketing, ethics and compliance, and certain other shared services. These allocations were based primarily on specific identification of time or activities associated with us, employee headcount or our relative size compared to Occidental. Our management believes the assumptions underlying the financial statements, including the assumptions regarding allocating expenses from Occidental, are reasonable. However, the financial statements for the pre-Spin-off periods may not include all of the actual expenses that would have been incurred, may include duplicative costs and may not reflect our results of operations, financial position and cash flows had we operated as a stand-alone public company during the periods presented. Actual costs that would have been incurred if we had been a stand-alone company prior to the Spin-off would depend on multiple factors, including organizational structure and strategic and operating decisions.

Prior to the Spin-off, we participated in Occidental's centralized treasury management program and did not incur any debt. Excess cash generated by our business was distributed to Occidental, and likewise our cash needs were provided by Occidental, in the form of contributions.

Had we been a stand-alone company for the full year 2014, and had the same level of debt throughout the year as we did on December 31, 2014, of approximately $6.4 billion, we would have incurred $314 million, of interest expense, on a pro-forma basis, for the year ended December 31, 2014, compared to the $72 million pre-tax interest expense reported in our statement of operations for the year then ended.

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 index prices and differentials may fluctuate significantly, generally as a result of changes in supply and demand and other market-related variables. These and other factors make it impossible to predict realized prices reliably. Much of the global exploration and production industry is challenged at current price levels, putting pressure on the industry's ability to generate positive cash flow and access capital.

We respond to economic conditions primarily by adjusting our capital investments to be in line with current economic conditions, including adjusting the size and allocation of our capital program, aligning the size of our work force with the level of activity, continuing to drive efficiencies and cost savings in the organization and working with our suppliers and service providers to adjust the cost of goods and services to current market conditions. The changes in our capital program will negatively impact our production levels and cash flows.

We will also continue to be strategic and opportunistic in implementing our hedging program. Our objective is to protect against the cyclical nature of commodity prices to protect our cash flows, margins and capital investment program and improve our ability to comply with our credit facility covenants in case of further price deterioration. We executed hedges for 2016 using Brent-based costless collars, representing annualized average production of 30,600 barrels of oil per day and a weighted-average price of $50.88 per barrel, but can give no assurance that they will be adequate to accomplish our hedging program objectives.

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 imports over 60% of its oil and approximately 90% of its natural gas. A vast majority of the oil is imported via supertanker, with a minor amount arriving by rail. 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 country to California will continue contributing to higher realizations than most other U.S. oil markets for comparable grades. Beginning in late 2015, the U.S. federal government allowed the export of crude oil. As a result, we are opportunistically pursuing newly opened export markets for our crude oil production to improve our margins. Due to much lower levels of natural gas production compared to our oil production, the changes in natural gas prices have a significantly lower impact on our operating results. Lower natural gas prices generally have a positive effect on our steamflood projects, which use natural gas to generate the steam being injected. Average oil prices were significantly lower in 2015 than 2014, caused by a steep decline in prices that started in the last half of 2014 and continued into 2015. Average Brent oil prices were $99.51 per barrel in 2014 and $53.64 per barrel in 2015, ending 2015 at $37.28. Our realized price for crude oil, taking into account our hedges, as a percentage of Brent prices was approximately 92% and 93% for 2015 and 2014, respectively. In the early part of 2016, oil prices have averaged below the year-end 2015 level.

The following table presents the average daily Brent oil, WTI oil and NYMEX gas prices for each of the years ended December 31, 2015, 2014 and 2013:

	2015	2014	2013
Brent oil ($/Bbl)	$ 53.64	$ 99.51	$ 108.76
WTI oil ($/Bbl)	$ 48.80	$ 93.00	$ 97.97
NYMEX gas ($/Mcf)	$ 2.75	$ 4.34	$ 3.66

Oil prices and differentials will continue to be 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 and refining disruptions, currency exchange rates, worldwide drilling and exploration activities, the effects of conservation, weather, geophysical and technical limitations, refining and processing disruptions, transportation bottlenecks and other matters affecting the supply and demand dynamics for our products, technological advances and regional market conditions; transportation capacity and costs in producing areas; and the effect of changes in these variables on market perceptions.

Prices and differentials for natural gas liquids (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 the pricing volatility.

Natural gas prices and differentials are strongly affected by local supply and demand fundamentals, as well as availability of transportation capacity from producing areas.

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 provide part of the electricity output from our Elk Hills power plant to reduce Elk Hills field operating costs and increase reliability and sell the excess to the grid and to others under contract. Further, energy costs, primarily in the form of electricity, and the cost of natural gas used to generate steam can also impact the level of our earnings.

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 quarterly earnings during the year.

Income Taxes

Deferred tax assets, net of deferred tax liabilities of $454 million, were approximately $258 million at December 31, 2015. The current portion of the net deferred tax assets was $59 million, which was reported in other current assets, and the noncurrent portion of $199 million was reported in other assets. The realization of deferred tax assets is assessed periodically based on several factors, including our expectation of sufficient future income and reversal of taxable temporary differences. In the fourth quarter of 2015, we recorded a valuation allowance, net of the federal benefit for the state-related portion, of $294 million against a portion of our deferred tax assets, which we do not believe are more likely than not realizable due to the decline in commodity prices.

As further explained in the ''Liquidity and Capital Resources'' section below, in December 2015, we executed an exchange whereby we issued second-lien secured notes in exchange for a portion of our unsecured notes. As a result of this debt exchange, we recognized cancellation of debt income of $1.39 billion in 2015, including $830 million of original issue discount, which represented the excess of the face value of the newly-issued notes over their fair value. The original issue discount will be deducted in our tax returns over a seven-year period. The tax gain exceeded our operating loss for the year. We expect to utilize our existing net operating loss (NOL) carryforwards from 2014 as well as our anticipated 2016 NOLs to offset the current tax liability resulting from this gain. As a result, the related $310 million of current federal and state tax provision has been reported in other long-term liabilities in the accompanying balance sheets. We expect this amount to become a deferred tax liability in 2016 as the anticipated losses are incurred.

The following table sets forth the calculation of our effective income tax rate for each of the years ended December 31 (in millions):

	2015	2014	2013
Pre-tax income / (loss)	$ (5,476)	$ (2,421)	$ 1,447
Income tax (expense) / benefit	1,922	987	(578)
Net income / (loss)	$ (3,554)	$ (1,434)	$ 869
Effective tax rate	35%	41%	40%

Operations

We conduct our operations through fee interests, land 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 2.4 million net acres, approximately 60% of which we hold in fee. 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 our operations, including gas plants, oil and gas gathering systems, a power plant and other related assets 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 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 such capital and production costs and an additional share for profit. Our portion of the production represents volumes: (1) to recover our partners' share of capital and production costs that we incur on their behalf, (2) for our share of contractually defined base production and (3) for our share of production in excess of contractually defined base production for each period. We realize our share of capital and production costs, and generate returns, through our defined share of production from (2) and (3) 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, however, our net economic benefit is greater when product prices are higher. These contracts represented approximately 17% of our production for the year ended December 31, 2015.

Results

Results for the year ended December 31, 2015 were a net loss of $3.6 billion, compared with a net loss of $1.4 billion for the year ended December 31, 2014. The net loss in 2015 reflected after-tax items including a $2.9 billion non-cash impairment charge for proved and unproved properties in the fourth quarter of 2015, approximately $42 million in write-down of certain other assets, $40 million in early retirement and severance costs, $7 million in rig termination and other costs and $5 million in debt transactions costs, net, partially offset by $34 million in hedge-related gains. Additionally, the net loss for 2015 included a $294 million net tax charge for the valuation allowance on our deferred tax assets. The net loss for 2015, excluding these items, was $311 million as reflected in the table below.

The net loss in 2014 largely reflected a $2.0 billion non-cash after-tax impairment charge for proved and unproved properties in the fourth quarter of 2014 and approximately $64 million in after-tax charges for rig terminations, other price-related charges and Spin-off and transition related costs. There were no similar charges or costs in 2013. Net income for 2014, excluding these charges, was $650 million as reflected in the table below.

The table below reconciles net income / (loss) to adjusted net income and lists unusual and infrequent items affecting earnings for each year (in millions):

	2015	2014	2013
Adjusted net income / (loss)	$ (311)	$ 650	$ 869
Unusual and infrequent items:			
Asset impairments	(4,852)	(3,402)	—
Write-down of certain other assets	(71)		
Early retirement and severance costs	(67)	—	—
Rig terminations and other costs	(11)	(52)	—
Debt transactions	(8)		
Non-cash hedge-related gains	52	—	—
Spin-off and transition related costs	—	(55)	—
Valuation allowance for deferred tax assets	(294)		
Tax effects of these items and related adjustments	2,008	1,425	—
Net income / (loss)	$ (3,554)	$ (1,434)	$ 869

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

Adjusted results for 2015, compared to 2014, reflected significantly lower realized product prices in 2015 and higher interest expense, partially offset by the benefits of higher oil production, lower production costs, depreciation, depletion and amortization (DD&A), exploration expense and ad valorem tax expense. Production costs decreased in 2015 as a result of various efficiency and cost cutting measures implemented across our operations, including lower well maintenance and workovers, well servicing efficiency, surface operations, reduced energy use through efficiencies, employee reductions, including early retirements, as well as lower prices for injectants, such as natural gas, and electricity. Adjusted general and administrative expenses also decreased in 2015 as a result of efficiency and cost-cutting measures implemented during the year and lower employee-related costs.

Adjusted results for 2014, compared to 2013, benefited from higher oil production and higher realized natural gas prices, which were more than offset by lower realized oil prices and lower realized NGL prices and volumes, and higher production costs, depreciation rates, property taxes, general and administrative costs and interest expenses. In addition, unit production costs increased mainly due to higher natural gas and other energy costs, and expenses for surface operations and maintenance.

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

	2015	2014	2013
Oil (MBbl/d)			
San Joaquin Basin	64	64	58
Los Angeles Basin	34	29	26
Ventura Basin	6	6	6
Sacramento Basin	—	—	—
Total	104	99	90
NGLs (MBbl/d)			
San Joaquin Basin	17	18	19
Los Angeles Basin	—	—	—
Ventura Basin	1	1	1
Sacramento Basin	—	—	—
Total	18	19	20
Natural gas (MMcf/d)			
San Joaquin Basin	172	180	182
Los Angeles Basin	2	1	2
Ventura Basin	11	11	11
Sacramento Basin	44	54	65
Total	229	246	260
Total Production (MBoe/d)[(a)]	160	159	154

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 price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, for the year ended December 31, 2015, the average prices of Brent oil and NYMEX natural gas were $53.64 per barrel and $2.75 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 20 to 1.

Daily oil and gas production volumes averaged 160,000 Boe for the year ended December 31, 2015, compared with 159,000 Boe for the year ended December 31, 2014. Average daily oil production increased by 5,000 barrels, or by five pecent, while daily NGL production decreased by 1,000 barrels and natural gas production decreased by 17 MMcf. The increase in oil production and decline in NGL and natural gas production reflected our emphasis on higher margin oil drilling and reduction of drilling capital for natural gas. Oil and total production for 2015 were both at record levels.

Daily oil and gas production volumes averaged 159,000 Boe for the year ended December 31, 2014, compared with 154,000 Boe for the year ended December 31, 2013. Average daily oil production increased by 9,000 barrels, or by ten percent, while daily NGL production decreased by 1,000 barrels and natural gas production decreased by 14 MMcf. The increase in oil production and decline in NGL and natural gas production reflected our emphasis on higher margin oil drilling and reduction of drilling capital for natural gas.

The following table sets forth the average realized prices for our products:

	2015	2014	2013
Oil prices with hedge ($ per Bbl)	$ 49.19	$ 92.30	$ 104.16
Oil prices without hedge ($ per Bbl)	$ 47.15	$ 92.30	$ 104.16
NGLs prices ($ per Bbl)	$ 19.62	$ 47.84	$ 50.43
Gas prices with hedge ($ per Mcf)	$ 2.66	$ 4.39	$ 3.73

The following table presents our average realized prices as a percentage of Brent, WTI and NYMEX for each of the three years in the period ended December 31, 2015:

	2015	2014	2013
Oil with hedge as a percentage of Brent	92%	93%	96%
Oil without hedge as a percentage of Brent	88%	93%	96%
Oil without hedge as a percentage of WTI	97%	99%	106%
Gas with hedge as a percentage of NYMEX	97%	101%	102%

Balance Sheet Analysis

The changes in our balance sheet as of December 31, 2015 and 2014, are discussed below:

	2015	2014
	(in millions)	
Cash and cash equivalents	$ 12	$ 14
Trade receivables, net	$ 200	$ 308
Inventories	$ 58	$ 71
Other current assets	$ 227	$ 308
Property, plant and equipment, net	$ 6,312	$ 11,685
Other assets	$ 244	$ 43
Current maturities of long-term debt	$ 100	$ —
Accounts payable	$ 257	$ 588
Accrued liabilities	$ 222	$ 334
Current income taxes	$ 26	$ —
Long-term debt—principal amount	$ 6,043	$ 6,360
Deferred gain and financing costs, net	$ 491	$ (68)
Deferred income taxes	$ —	$ 2,055
Other long-term liabilities	$ 830	$ 549
Equity	$ (916)	$ 2,611

See ''Liquidity and Capital Resources'' for discussion of changes in our cash and cash equivalents and long-term debt.

The decrease in trade receivables was largely the result of lower product prices and lower oil volumes for the fourth quarter of 2015, compared to the same period of 2014. The decrease in other current assets reflected lower greenhouse gas emission and other assets, partially offset by increases in the market value of our derivative assets. The decrease in property, plant, and equipment, net reflected the impairment charge for proved and unproved properties and additional DD&A incurred in 2015, partially offset by capital investments. The increase in other assets was due to the noncurrent portion of net deferred tax assets that resulted from our asset impairment charge for the year.

The decrease in accounts payable reflected lower capital investments and operating costs in the last quarter of 2015 compared with the same period in 2014. The decrease in accrued liabilities at year end 2015 compared to 2014 reflected lower greenhouse gas emission liabilities and accrued interest, in both cases largely due to the timing of payments. The elimination of the deferred income tax liability resulted from the impairment charges, partially offset by tax depreciation of our property, plant and equipment. The impairment charges resulted in the recognition of a net deferred tax asset. Other long-term liabilities increased as a result of additional taxes resulting from the December 2015 debt exchange, partially offset by lower asset retirement obligations. The decrease in equity primarily reflected our current-year net loss.

Statement of Operations Analysis

The following table presents the results of our operations, including the unusual and infrequent items discussed in the ''Results'' section above:

	2015	2014	2013
		(in millions)	
Oil and natural gas sales[a]	$ 2,294	$ 4,023	$ 4,139
Other revenue	109	150	145
Production costs	(951)	(1,057)	(986)
General and administrative expenses	(354)	(302)	(266)
Depreciation, depletion and amortization	(1,004)	(1,198)	(1,144)
Asset impairments	(4,852)	(3,402)	—
Taxes other than on income	(180)	(217)	(185)
Exploration expense	(36)	(139)	(116)
Interest and debt expense, net	(326)	(72)	—
Other expenses	(176)	(207)	(140)
Income tax (expense) / benefit	1,922	987	(578)
Net income / (loss)	$ (3,554)	$ (1,434)	$ 869
EBITDAX[b]	$ 906	$ 2,548	$ 2,733
Effective tax rate	35%	41%	40%

(a) Includes related-party sales for 2014 and 2013.

(b) We define EBITDAX consistent with our Credit Facilities as earnings before interest expense; income taxes; depreciation, depletion and amortization; exploration expense; and certain other non-cash items and unusual, infrequent charges. Our management believes EBITDAX provides useful information in assessing our financial condition, results of operations and cash flows and is widely used by the industry and investment community. The amounts included in the calculation of EBITDAX were computed in accordance with GAAP. This measure is a material component of our financial covenants under our Credit Facilities and is provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP. Certain items excluded from

EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. 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 non-GAAP financial measure of EBITDAX to the GAAP financial measure of net income / (loss) (in millions):

	2015	2014	2013
Net income / (loss)	$ (3,554)	$ (1,434)	$ 869
Interest expense	326	72	—
Income tax expense / (benefit)	(1,922)	(987)	578
Asset impairments	4,852	3,402	—
Depreciation, depletion and amortization	1,004	1,198	1,144
Exploration expense	36	139	116
Other non-cash items	59	51	26
Unusual and infrequent charges[a]	105	107	—
EBITDAX	$ 906	$ 2,548	$ 2,733

(a) For 2015, includes early retirement and severance costs, hedge related gains, debt related items and rig termination costs. For 2014, includes rig terminations and other price-related costs, and Spin-off and transition related costs.

The following represents key metrics of our oil and gas operations, excluding certain corporate items and asset impairments, on a per Boe basis for the years ended December 31, 2015, 2014 and 2013:

	2015	2014	2013
Production costs	$ 16.30	$ 18.23	$ 17.56
General and administrative expense, as adjusted[a]	$ 1.00	$ 1.47	$ 1.46
Other operating expenses, as adjusted[b]	$ 0.36	$ 0.55	$ 0.60
Depreciation, depletion and amortization	$ 16.72	$ 20.40	$ 20.11
Taxes other than on income	$ 2.67	$ 3.50	$ 3.05

(a) For 2015, the amount excludes unusual and infrequent costs of $0.31 per Boe related to early retirement and severance costs associated with field personnel. For 2014, the amount excludes unusual and infrequent costs of $0.10 per Boe related to Spin-off and transition related costs.

(b) For 2015, the amount excludes unusual and infrequent costs related to the write-down of certain assets and rig termination charges of $1.42 per Boe. For 2014, the amount excludes unusual and infrequent costs related to rig termination charges and Spin-off and transition related costs of $0.97 per Boe.

The following table presents the reconciliation of general and administrative expenses to adjusted general and administrative expenses (in millions):

	2015	2014	2013
General and administrative expenses	$ 354	$ 302	$ 266
Early retirement and severance costs	(67)	—	—
Adjusted general and administrative expenses	$ 287	$ 302	$ 266

Year Ended December 31, 2015 vs. 2014

Oil and natural gas sales decreased 43%, or $1.7 billion, in 2015 compared to 2014, primarily due to an approximately $1.55 billion negative impact from lower oil prices, $190 million from lower NGL prices and volumes and $180 million from lower natural gas prices and volumes. The lower oil prices resulted from a significant decrease in benchmark prices generally, as well as higher differentials to those benchmark prices in 2015, mainly caused by local refinery and pipeline events. The decrease was partially offset by an approximately $70 million positive effect of higher oil volumes and a gain of approximately $130 million from hedge-related activity, of which $50 million was non-cash. Average oil production increased by 5% or 5,000 barrels per day to 104,000 barrels per day in the year ended 2015 compared to the prior year. NGL production decreased by 5% to 18,000 barrels per day and natural gas production decreased by 7% to 229 MMcf per day.

Other revenue in 2015, primarily attributable to sales from our Elk Hills power plant, decreased 27%, or $41 million, due to lower prices for power sold by our Elk Hills power plant.

Production costs decreased 10%, or $106 million, to $16.30 per Boe in 2015, compared to $18.23 per Boe in 2014, an 11% reduction on a Boe basis. The decrease was driven by cost reductions across the board, particularly in well maintenance and workovers, well servicing efficiency, surface operations, reduced energy use through efficiencies and employee reductions, including early retirements, and was aided by lower natural gas and electricity prices.

Adjusted general and administrative expenses, which excludes voluntary retirement and employee reduction costs, decreased 5%, or $15 million, in 2015 compared to 2014, largely due to our cost reduction efforts and lower stock-based compensation costs resulting from a lower year-end stock price. The non-cash portion of adjusted G&A, comprising equity compensation and pension costs, was approximately $35 million and $30 million for 2015 and 2014, respectively.

DD&A expense decreased 16%, or $194 million, in 2015 compared to 2014, almost all of which was due to a lower DD&A rate resulting from the 2014 impairment charges, partially offset by higher 2015 production.

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. As a result, in the fourth quarter of 2015, we recorded pre-tax asset impairment charges of $4.9 billion on proved and unproved properties throughout our asset base. The impairment charge was related to certain properties in the San Joaquin, Los Angeles and Ventura basins, as well as our gas properties in the Sacramento basin. Approximately $100 million of the charge was related to unproved acreage. We evaluate 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 current environment. To the extent prices recover to levels above the year-end forward price curves, we would expect a substantial portion of these assets would ultimately become economic in an improved price environment.

Taxes other than on income decreased 17%, or $37 million, in 2015 compared to 2014, primarily due to a $25 million decrease in property taxes and a $10 million decrease in greenhouse gas emissions costs.

Exploration expense decreased 74%, or $103 million, in 2015 compared to 2014, consistent with our reduced exploration activity.

The increase in interest and debt expense, net, of $254 million in 2015 compared to 2014, resulted from the debt incurred in connection with the Spin-off in the fourth quarter of 2014.

Other expenses decreased 15%, or $31 million, in 2015 compared to 2014, reflecting lower natural gas costs for our Elk Hills power plant and lower rig termination costs.

Provision for income taxes showed a benefit of $1.9 billion in 2015, which reflected a pre-tax loss of approximately $5.5 billion, compared to a benefit of $987 million in 2014, which reflected a pre-tax loss of approximately $2.4 billion. The 2015 benefit was net of a $294 million charge related to a valuation allowance, which resulted in a lower effective tax rate in 2015.

Year Ended December 31, 2014 vs. 2013

Oil and natural gas sales decreased 3%, or $116 million, in 2014 compared to 2013. Lower oil prices, which declined significantly in the second half of 2014, contributed $377 million to this decrease, lower natural gas volumes contributed $71 million and lower NGL prices and volumes contributed $54 million. Partially offsetting these decreases were $318 million related to higher oil volumes and $61 million related to higher natural gas prices. Crude oil production increased by 9,000 Boe/d while our NGL and natural gas production decreased by 1,000 Boe/d and 14 MMcf/d, or approximately 2,000 Boe/d, respectively. The lower NGL and natural gas production reflects our planned shift in our capital toward higher margin oil projects.

Other revenue in 2014, attributable to sales from our Elk Hills power plant, was consistent with 2013.

Production costs increased by 7%, or $71 million, to $18.23 per Boe in 2014, compared to $17.56 per Boe in 2013. Of this increase, $32 million was due to higher volumes and $31 million due to higher costs for natural gas used in our steamflood operations and higher energy costs and expenses for surface operations and maintenance. In the fourth quarter we started an aggressive cost containment program and have seen costs start to decline in December.

General and administrative expenses increased 12%, or $36 million, in 2014 compared to 2013, mostly due to higher employee related costs and costs related to the Spin-off.

DD&A expense increased 5%, or $54 million, in 2014 compared to 2013. Of this increase, $22 million was attributable to higher volumes and $32 million resulted from a higher DD&A rate, due to additional capital investments.

At year end 2014, we performed impairment tests with respect to our proved and unproved properties as a result of significant declines in oil prices largely during the last half of 2014. As a result, in the fourth quarter of 2014, we recorded pre-tax asset impairment charges of $3.4 billion on proved and unproved properties throughout our asset base. The impairment charge was related to certain properties in the San Joaquin and Los Angeles basins and a portion of our assets in the Ventura basin, as well as our gas properties in the Sacramento basin. Approximately $650 million of the charge was related to unproved acreage. We evaluate 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 current environment. To the extent prices recover to levels above the year-end forward price curves, we would expect a substantial portion of these assets would ultimately become economic in an improved price environment.

Taxes other than on income increased 17%, or $32 million, in 2014 compared to 2013, reflecting higher property taxes largely due to a refund received in 2013, which reduced that year's property taxes.

Exploration expense increased 20%, or $23 million, in 2014 compared to 2013, mostly due to higher dry hole expenses in the San Joaquin basin, including $12 million of other charges.

Interest expense in 2014 was $72 million, due to our debt incurred in connection with the Spin-off of approximately $6.4 billion in the fourth quarter of 2014.

Other expenses increased 48%, or $67, million in 2014 compared to 2013, and included rig termination costs of $33 million and $35 million for Spin-off, transition and other related items.

Provision for income taxes showed a benefit of $987 million in 2014, reflecting the pre-tax loss of approximately $2.4 billion and a slight increase in the effective tax rate compared to 2013.

Liquidity and Capital Resources

The primary source of liquidity and capital resources to fund our capital program and other obligations has been cash flow from operations. Operating cash flows, however, are largely dependent on oil and natural gas prices and differentials, sales volumes and costs. Oil and natural gas prices declined significantly during fiscal year 2015 and have declined even further through fiscal 2016 to date. The price of Brent crude oil dropped below $28 per barrel at one point in January 2016. These lower commodity prices have negatively impacted revenues, earnings and cash flows, and sustained low oil and natural gas prices will have a material and adverse effect on our liquidity position.

Much of the global exploration and production industry is challenged at current price levels, putting pressure on the industry's ability to generate positive cash flow and access capital. If commodity prices were to prevail through the year at about current levels, we may need to depend on our revolving credit facility for a portion of our cash needs for the year. Our ability to borrow under our revolving credit facility is limited by our ability to comply with its covenants, including quarterly financial covenants, and by our borrowing base. Effective February 2016, the borrowing base under our credit facilities was $2.3 billion. As of January 31, 2016, after giving effect to the February borrowing base redetermination, we would have had approximately $560 million of available borrowing capacity under our revolving credit facility, subject to further limitations in order for us to remain compliant with our financial covenants.

If prices for our products remain stable or increase, we expect our needs for our annual interest payments, operational expenses, capital investments and other obligations for the next twelve months will be met by cash generated from operations and, if necessary, borrowings under our revolving credit facility, while remaining compliant with our financial covenants. However, further price declines would reduce our cash flows from operations over such period and may limit our access to borrowing capacity or cause a default under our revolving credit facility, which would give our lenders the ability to foreclose on our secured assets. If we experience further commodity price declines, and are unable to achieve improved liquidity through additional financing, asset monetizations, restructuring of our debt obligations or otherwise, cash and expected available credit capacity may not be sufficient to meet our commitments over the next twelve months.

In addition, in response to commodity price declines, we reduced our fiscal year 2016 capital budget to a current planned amount of $50 million compared to 2015 actual capital expenditures of

$401 million, consistent with our continued intent to reduce our capital program from 2015 levels to a level consistent with our expected operating cash flow. The curtailment of the development of our properties will lead to a decline in our production and possibly reserves. Over the long term, a continued decline in our production and reserves would reduce our liquidity and ability to satisfy our debt obligations by negatively impacting our cash flow from operations and the value of our assets. We are pursuing certain transactions that, if consummated, may provide us with additional capital beyond our operating cash flows; however, we cannot assure that any of these transactions will be completed.

We have taken a number of other steps to better align our cost structure with the current price environment. In the fourth quarter of 2015, we reduced our total workforce to approximately 1,700 employees through early retirements and other employee actions. In February 2016, we implemented additional employee actions to reduce our workforce to below 1,500 employees. In addition, the management team accepted a 10% reduction in their salaries. We also substantially reduced our matching contributions to employees' 401(k) plans and suspended our retirement contributions to other non-qualified plans. As a result, in 2016, we expect to meaningfully reduce our production costs and general and administrative expense below 2015 levels. We expect that these measures will help offset the cash flow effects of prolonged low or deteriorating commodity prices to some extent.

We are also pursuing a number of alternatives to deleverage our balance sheet and better align our capital structure with the current commodity price environment. Potential transactions may include a combination of asset monetizations, joint ventures and other deleveraging opportunities, such as capital market alternatives. The asset monetization opportunities we are pursuing primarily involve our midstream and power assets. We may from time to time seek to pay down, retire or purchase our outstanding debt using cash or exchanging for other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on available funds, prevailing market conditions, our liquidity requirements, contractual restriction in our revolving credit agreement and other factors. The amounts involved may be material. We can give no assurance that any of these efforts will be successful or provide sufficient capital or deleveraging.

As discussed above, we have Brent-based crude oil hedges in place for 2016, representing average production of 44,700 barrels per day at a weighted-average price of $50.75 per barrel for the first half of 2016 and 15,500 barrels per day at a weighted-average price of $50.59 per barrel for the second half of 2016, but can give no assurance they will be adequate to accomplish our hedging program objectives. In addition, we entered into a Brent-based swap during the year for 1,000 barrels per day of our July through December 2016 crude oil production at $61.25 per barrel.

Credit Facilities

We have a credit agreement effective through September 2019 that provides for (i) a senior term loan facility (the Term Loan Facility) and (ii) a senior revolving loan facility (the Revolving Credit Facility and, together with the Term Loan Facility, the Credit Facilities). All borrowings under these facilities are subject to certain customary conditions. During the third quarter of 2015, our corporate ratings from Moody's Investors Service (Moody's) and Standard & Poor's Ratings Services (S&P) were downgraded, resulting in the imposition under our Credit Facilities of a borrowing base and a grant of security on a first-lien basis. On February 23, 2016, we received 100% bank approval to amend our Credit Facilities. Effective with the amendment, the borrowing base under our Credit Facilities was reduced to $2.3 billion and the Revolving Credit Facility commitments were reduced to $1.6 billion.

The Revolving Credit Facility includes a sub-limit of $400 million for the issuance of letters of credit. We are required to repay the Term Loan Facility in $25 million quarterly installments beginning on March 31, 2016. As of December 31, 2015, we had $739 million outstanding under our Revolving Credit Facility and $1.0 billion outstanding under the Term Loan Facility.

As amended, our financial performance covenants through December 31, 2016 comprise an obligation to achieve (i) a cumulative minimum EBITDAX during 2016 of $55 million through the first quarter, $130 million through the second quarter, $190 million through the third quarter and $250 million through the fourth quarter and (ii) a trailing twelve-month minimum interest coverage ratio of 2.00:1.00 as of the end of the first quarter of 2016, 1.50:1.00 as of the end of the second quarter, 1.25:1.00 as of the end of the third quarter and 0.70:1.00 as of the end of the fourth quarter. As of the end of the first quarter of 2017, the minimum interest coverage ratio will revert back to 2.00:1.00. We will not be subject to a maximum first lien senior secured leverage ratio for 2016. The amendment also suspends the requirement for us to comply with a trailing twelve-month maximum first lien senior secured leverage ratio of 2.25:1.00 until the end of the first quarter of 2017. If we continue to experience low commodity prices for our products and we are unable to execute on one of the strategic alternatives discussed above to manage our capital structure and address liquidity concerns prior to the first quarter of 2017, we may not be able to comply with the financial covenants under our Revolving Credit Facility applicable in 2017.

Except as otherwise agreed with our lenders for specific transactions, our Credit Facilities as amended require us to apply 100% of the proceeds from certain asset monetizations to repay loans outstanding under the Credit Facilities, except that we will be permitted to use up to 40% of proceeds from non-borrowing base asset sales to repurchase our notes to the extent available at a significant minimum discount to par, as specified in the amended facilities. Subject to compliance with our indentures, our amended facilities permit us to incur additional indebtedness to repurchase our notes to the extent available at a significant minimum discount to par, as specified in the amended facilities, as follows: (i) up to $1 billion, which may be secured by liens that are junior to the liens securing our Credit Facilities, provided that at least 60% of the proceeds from the new debt is used first to repay loans outstanding under the Credit Facilities, and (ii) up to $200 million, which may be secured by first-priority liens on our non-borrowing base properties. The amended Credit Facilities also permit us to incur up to an additional $50 million of non-Credit Facility indebtedness, which, subject to compliance with our indentures, may be secured; and the proceeds of which must be applied to repay loans outstanding under the Credit Facilities. All of the foregoing prepayments will be applied first to our Term Loan Facility and second to our Revolving Credit Facility after the Term Loan Facility has been fully repaid (with a corresponding reduction to the lenders' Revolving Credit Facility commitments). Our amended facilities also require us to apply cash on hand in excess of $150 million to repay amounts outstanding under our Revolving Credit Facility. Further, we are restricted from (i) paying dividends or making other distributions to common stockholders and (ii) making capital investments exceeding $100 million during 2016.

The amendment also imposed a semi-annual borrowing base redetermination each May 1 and November 1, commencing May 1, 2016. The borrowing base will be based upon a number of factors, including commodity prices and reserves levels. Increases in our borrowing base requires approval of at least 80% of our revolving lenders, as measured by exposure, while decreases require a two-thirds approval. We and the lenders (requiring a request from the lenders holding 2/3 of the commitments and outstanding loans), 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.

Borrowings under the Credit Facilities bear interest, at our election, at either a LIBOR rate or an alternate base rate (ABR) (equal to the greatest of (i) the administrative agent's prime rate, (ii) the one-month LIBOR rate plus 1.00% and (iii) the federal funds effective rate plus 0.50%), in each case plus an applicable margin. This applicable margin is based, while our total leverage ratio exceeds 3.00:1.00, on our borrowing base utilization and effective February 2016 will vary from (a) in the case of LIBOR loans, 2.50% to 3.50% and (b) in the case of ABR loans, 1.50% to 2.50%. The unused portion of the Revolving Credit Facility, as it may be limited by the borrowing base, is subject to a commitment fee equal to 0.50% per annum. We also pay customary fees and expenses under the Credit Facilities. 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.

Effective February 2016, all obligations under the Credit Facilities are guaranteed jointly and severally by all of our material wholly-owned subsidiaries. The assets and liabilities of subsidiaries not guaranteeing the debt are de minimis.

Substantially all of the restrictions imposed by the recent amendment to the Credit Facilities, other than the requirement for semi-annual borrowing base redeterminations, may terminate in the future if we are able to comply with the financial performance covenants as they existed prior to giving effect to the recent amendment. If we were to breach any of our Credit Facility covenants, our lenders would be permitted to accelerate the principal amount due under the Credit Facilities and foreclose on the assets securing them. If payment were accelerated under our Credit Facilities, it would also result in a default under our outstanding notes and permit acceleration and foreclosure on the assets securing the secured notes.

Senior Notes

On October 1, 2014, we issued $5.00 billion in aggregate principal amount of our senior unsecured notes, comprising $1.00 billion of 5% senior unsecured notes due January 15, 2020 (the 2020 notes), $1.75 billion of 5 1/2% senior unsecured notes due September 15, 2021 (the 2021 notes) and $2.25 billion of 6% senior unsecured notes due November 15, 2024 (the 2024 notes and together with the 2020 notes and the 2021 notes, the unsecured notes). The unsecured notes were issued at par and are fully and unconditionally guaranteed on a senior unsecured basis by all of our material subsidiaries. We used the net proceeds from the issuance of the unsecured notes to make a $4.95 billion cash distribution to Occidental in October 2014.

In December 2015, we exchanged $534 million, $921 million and $1,358 million in aggregate principal amount of the 2020 notes, the 2021 notes, and the 2024 notes, respectively, for $2.25 billion in aggregate principal amount of newly issued 8% senior secured second lien notes due December 15, 2022 (the 2022 notes). We recorded a deferred gain of approximately $560 million on the debt exchange, which will be amortized using the effective interest rate method over the term of the 2022 notes. Additionally, we incurred approximately $28 million in third party costs which were fully expensed in 2015. The newly-issued second lien notes are secured on a second-lien basis, subject to the terms of an intercreditor agreement and collateral trust agreement by a lien on the same collateral used to secure our obligations under our Credit Facilities.

In December 2015, we repurchased approximately $33 million in principal amount of the 2020 notes for $12 million in cash.

We will pay interest semiannually in cash in arrears on January 15 and July 15 for the 2020 notes, on March 15 and September 15 for the 2021 notes and on May 15 and November 15 for the

2024 notes. We will pay interest on the 2022 notes semiannually in cash in arrears on June 15 and December 15, beginning on June 15, 2016.

The indentures governing the senior unsecured notes and the second-lien secured notes each include covenants that, among other things, limit our and our restricted subsidiaries' ability to incur debt secured by liens. The indentures also restrict our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. These covenants are subject to a number of important qualifications and limitations that are set forth in the indenture. 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 indentures) with respect to a series of notes, we will be required, unless we have exercised our right to redeem the notes of such series, to offer to purchase the notes of such series at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest. The indenture governing our second-lien secured notes also restricts our ability to sell certain assets and to release collateral from liens securing the second-lien secured notes.

Spin-off Related Distributions to Occidental

We used the net proceeds from the private placement of our notes in 2014 to make a $4.95 billion cash distribution to Occidental in October 2014. See ''—Senior Notes'' for more details regarding the terms of our senior notes. On November 25, 2014, we borrowed $1.0 billion under our Term Loan Facility and $50 million under a Revolving Credit Facility to make a $1.05 billion cash distribution to Occidental on November 26, 2014.

Cash Flow Analysis

	2015	2014	2013
		(in millions)	
Net cash flows provided by operating activities	$ 403	$ 2,371	$ 2,476
Net cash flows used in investing activities	$ (757)	$ (2,312)	$ (1,713)
Net cash flows provided by (used in) financing activities	$ 352	$ (45)	$ (763)
EBITDAX[(a)]	$ 906	$ 2,548	$ 2,733

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

The following table sets forth a reconciliation of the non-GAAP financial measure of EBITDAX to the GAAP measure of net cash provided by operating activities:

	2015	2014	2013
		(in millions)	
Net cash provided by operating activities	$ 403	$ 2,371	$ 2,476
Interest expense	326	72	—
Current income taxes	—	165	318
Cash exploration expenses	27	38	44
Changes in operating assets and liabilities	147	(143)	(103)
Other, net	3	45	(2)
EBITDAX	$ 906	$ 2,548	$ 2,733

Year Ended December 31, 2015 vs. 2014

Our operating cash flows in 2015 decreased by $2.0 billion from $2.4 billion in 2014 to $403 million in 2015. The decrease reflected approximately $1.8 billion in lower sales primarily due to lower oil prices and lower NGL and natural gas prices and volumes and $360 million of higher interest payments, partially offset by lower operating costs. Additionally, changes in working capital resulted in an approximate $290 million reduction in operating cash due to lower operating costs resulting in lower year-end 2015 payables, lower accruals for payroll and bonuses in line with our reduced workforce, partially offset by lower receivables from customers due to lower year-end 2015 product prices. Further, the 2014 positive working capital reflected the effect of higher operating, general and administrative and other costs and related higher accruals from the previous year-end, in line with a higher level of activity.

Our cash flows used in investing activities decreased by approximately $1.6 billion from $2.3 billion in 2014 to $757 million in 2015. The decrease reflected reduced capital investments of $1.7 billion and lower acquisition costs of approximately $140 million, partially offset by approximately $200 million in 2014 capital investments paid in 2015.

Our net cash flows from financing activities changed from $45 million used in 2014 to $352 million provided in 2015. The change is primarily due to 2015 net proceeds from the revolving credit facility of $379 million, largely to fund the working capital uses to pay for the fourth quarter 2014 capital investments and $8 million from the issuance of common stock, partially offset by 2015 debt repurchase and amendment costs of $23 million and $12 million in cash dividends paid.

Year Ended December 31, 2014 vs. 2013

Our operating cash flows in 2014 decreased by $105 million from $2.5 billion in 2013 to $2.4 billion in 2014. The decrease reflected approximately $110 million in lower sales due to lower oil and NGL prices partially offset by higher oil volumes and gas prices, higher interest expense of $70 million, higher production costs of approximately $70 million, higher taxes other than on income of $30 million, higher general and administrative costs of $40 million, partially offset by lower income taxes of $150 million and working capital changes of $40 million in 2014 compared to 2013.

Our cash flows used in investing activities in 2014 increased by approximately $600 million, to $2.3 billion, compared to $1.7 billion in 2013. The increase mainly consisted of approximately $420 million of higher capital investments and higher acquisition costs of $240 million, partially offset by an approximately $70 million increase in capital accruals. For 2013, the capital accrual amount was not material.

Our net cash flows used in financing activities decreased by approximately $720 million in 2014, compared to 2013, and reflected the dividend distribution of $6.0 billion to Occidental prior to the Spin-off, proceeds of approximately $6.3 billion of debt, net of $70 million of debt issuance costs, and lower excess cash distributions to Occidental prior to the Spin-off.

Acquisitions

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. Our asset acquisition and disposition program contemplates transactions designed to upgrade our portfolio, focusing on strategic bolt-on properties that complement our existing positions.

During the year ended December 31, 2014, we paid approximately $290 million to acquire certain producing and nonproducing oil and gas properties, including oil and gas properties in the Ventura Basin purchased for approximately $200 million in the fourth quarter of 2014.

During the year ended December 31, 2013, we paid approximately $50 million to acquire certain oil and gas properties. An acquisition in the San Joaquin basin also included an obligation to invest at least $250 million on exploration and development activities over a period of five years from the date of acquisition. We currently plan to invest this amount in capital during that period. Any deficiency in meeting this capital investment obligation would need to be paid in cash at the end of the five-year period. Through December 31, 2015, we have already fulfilled approximately 30% of this obligation.

2015 Capital Program and 2016 Capital Budget

In 2015, we invested approximately $400 million of capital, predominantly targeting projects in the San Joaquin, Los Angeles and Ventura basins, as compared to approximately $2.1 billion in 2014. Virtually all of our 2015 capital was directed towards oil-weighted production consistent with 2014. Of the 2015 capital program, approximately $130 million was allocated to drilling wells, $120 million to facilities and compression expansion, $55 million to workovers, $40 million to maintenance and occupational health, safety and environmental projects, $15 million to exploration, $10 million to 3D seismic and the rest to other items.

The table below sets forth our 2015 capital investments for the year ended December 31, 2015 (in millions):

	Conventional				Unconventional		Total Capital
	Primary	Waterflood	Steamflood	Total	Primary	Other	Investments
Basin:							
San Joaquin	$ 47	$ 16	$ 142	$ 205	$ 25	$ —	$ 230
Los Angeles	—	95	—	95	—	—	95
Ventura	18	8	2	28	—	—	28
Sacramento	—	—	—	—	—	—	—
Basin Total	65	119	144	328	25	—	353
Exploration and Other	—	—	—	—	—	48	48
Total	$ 65	$ 119	$ 144	$ 328	$ 25	$ 48	$ 401

We focused a substantial majority of our 2015 capital on our mature steamfloods, waterfloods and capital workovers, all of which offer among the highest VCIs in our portfolio. We focus on creating value and are committed to internally fund our capital budget with operating cash flows. Our low decline assets plus our high level of operational control and absence of long term commitments give us the flexibility to adjust the level of such capital investments as circumstances warrant. For 2016, the Board has approved a capital program of $50 million to maintain the mechanical integrity of our facilities and systems and operate them safely. In light of current commodity prices, we have built a dynamic budget for 2016 that adjusts our activity to align investments with operating cash flows. We will monitor prices and cash flow throughout the year and, if oil prices improve, may deploy additional available and approved capital focusing initially on a combination of capital workovers and new wells that meet our VCI investment metrics.

Off-Balance-Sheet Arrangements

We have no 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 selling, general and administrative expenses. For more information, see ''Contractual Obligations.''

Contractual Obligations

The table below summarizes and cross-references our contractual obligations as of December 31, 2015. This summary indicates on- and off-balance-sheet obligations as of December 31, 2015.

	Payments Due by Year				
	Total	**2016**	**2017 and 2018**	**2019 and 2020**	**2021 and thereafter**
	(in millions)				
On-Balance Sheet					
Long-term debt—principal amount (Note 5)[(a)]	$ 6,143	$ 100	$ 200	$ 1,872	$ 3,971
Other long-term liabilities[(b)]	159	7	17	21	114
Off-Balance Sheet					
Operating leases	125	13	31	23	58
Purchase obligations[(c)]	346	67	235	34	10
Total	$ 6,773	$ 187	$ 483	$ 1,950	$ 4,153

(a) Excludes interest on the debt. As of December 31, 2015, interest on long-term debt totaling $2.2 billion is payable in the following years (in millions): 2016—$348 million, 2017 and 2018—$687 million, 2019 and 2020—$616 million, 2021 and thereafter—$592 million. The calculation of interest payable on the variable interest debt assumes the interest rate at December 31, 2015 to be the applicable interest rate for the entire term. In performing the calculation, the Revolving Credit Facility borrowings outstanding at December 31, 2015 of $739 million were assumed to be outstanding for the entire term of the agreement.

(b) Includes obligations under postretirement benefit and deferred compensation plans, as well as certain accrued liabilities.

(c) Amounts include payments, which will become due under long-term agreements to purchase goods and services used in the normal course of business to secure pipeline capacity, drilling rigs and services. These amounts were significantly reduced as a result of rig contract terminations in 2014. Long-term purchase contracts are discounted using a discount rate of 5.7%.

Lawsuits, Claims, Contingencies and Commitments

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. Reserves balances at December 31, 2015 and 2014 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, 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, 2015, we are not aware of material indemnity claims pending or threatened against the Company.

Critical Accounting Policies and Estimates

The process of preparing financial statements in accordance with generally accepted accounting principles requires management to select appropriate accounting policies and to make informed estimates and judgments regarding certain items and transactions. Changes in facts and circumstances or discovery of new information may result in revised estimates and judgments, and actual results may differ from these estimates upon settlement. We consider the following to be our most critical accounting policies and estimates that involve management's judgment and that could result in a material impact on the financial statements due to the levels of subjectivity and judgment.

Oil and Gas Properties

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, net of accumulated DD&A and any impairment charges. For assets acquired, initial PP&E cost is based on fair values at the acquisition date.

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 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.

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 capitalized development and successful exploration costs over proved developed reserves.

Proved oil and gas reserves and production volumes are used as the basis for recording depreciation and depletion of oil and gas producing properties. Proved reserves are those quantities of oil and 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—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, we receive a share of production from certain arrangements in the Wilmington field similar to production-sharing contracts to recover costs and generally an additional share for profit. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline. Overall, our net economic benefit from these contracts is greater at higher product prices. In other cases, particularly with long-lived properties, lower product prices may lead to a situation where production of a portion of proved reserves becomes uneconomical. For such properties, higher product prices typically result in additional reserves becoming economical. 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.

Additionally, we perform impairment tests with respect to our 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. Apart from the effect of product prices, we believe our approach to interpreting technical data regarding proved oil and gas reserves makes it more likely that future proved reserves revisions will be positive rather than negative.

The most significant ongoing financial statement effect from a change in our oil and gas reserves or impairment of the carrying value of our proved properties would be to the DD&A rate. For example, a 5% increase or decrease in the amount of oil and gas reserves would change the DD&A rate by approximately $1.00 per barrel, which would increase or decrease pre-tax income / (loss) by approximately $37 million annually based on production rates for the year ended December 31, 2015.

A portion of the carrying value of our oil and gas properties is attributable to unproved properties. At December 31, 2015, the net capitalized costs attributable to unproved properties were approximately $300 million. While exploration and development work progresses, the unproved amounts are not subject to DD&A until they are classified as proved properties. However, 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 timing of any write-downs of these unproved properties, if warranted, depends upon management's plans, the nature, timing and extent of future exploration and development activities and their results. We believe our current plans and exploration and development efforts will allow us to realize the carrying value of our unproved property balance at December 31, 2015.

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. 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 acreage. As a result of the impairment, we expect our 2016 DD&A rate to decrease by approximately $7.50 per barrel.

At year end 2014, we performed impairment tests with respect to our proved and unproved properties as a result of significant declines in oil prices largely during the last half of 2014. As a result, in the fourth quarter of 2014, we recorded pre-tax asset impairment charges of $3.4 billion on certain proved and unproved properties throughout our asset base. Approximately $650 million of the charge was related to unproved acreage.

We evaluate 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 current environment. To the extent prices recover to levels above the year-end forward price curves, we would expect a substantial portion of these assets would ultimately become economic in an improved price environment.

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 primarily apply the market approach for recurring fair value measurement, 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 and discounts those cash flows using a risk-adjusted discount rate.

The most significant items on our balance sheet that would be affected by recurring fair value measurements are derivatives. Based on year-end 2015 amounts on the balance sheet for derivatives, a 10% increase or decrease in their fair value would affect pre-tax earnings by approximately $9 million.

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. See ''—Lawsuits, Claims, Contingencies and Commitments'' for additional information.

Significant Accounting and Disclosure Changes

In November 2015, the Financial Accounting Standards Board (FASB) issued rules requiring that deferred income tax liabilities and assets be classified as noncurrent in a classified balance sheet. These new rules will be effective for annual and interim periods beginning after December 15, 2016 and can be applied either retrospectively or prospectively with earlier application permitted. While we are evaluating any potential impact of these rules, we currently believe the effect of the new rules will not have a material impact on our financial statements.

In September 2015, the FASB issued rules that require an acquirer in a business combination account for measurement-period adjustments during the period in which it determines the amount of the adjustment, rather than retrospectively. These new rules will be effective for annual and interim periods beginning after December 15, 2015 and must be applied prospectively. We do not expect these new rules to have a material impact on our financial statements.

In August 2015, the FASB issued rules to defer the effective date of its new revenue recognition rules to annual and interim reporting periods beginning after December 15, 2017. Earlier application is permitted only as of annual and interim reporting periods beginning after December 15, 2016. While we are evaluating any potential impact of these rules, we currently believe the effect of the new rules will not have a material impact on our financial statements.

In July 2015, the FASB issued rules to simplify the accounting for employee benefit plans by removing the requirement for plan investments to be disaggregated by class. Under the new guidance, a plan will disaggregate its investments measured using fair value only by general type (e.g., common stocks, corporate bonds, mutual funds). These new rules will be effective for fiscal years beginning after December 15, 2015 and must be applied retrospectively with earlier application permitted. We do not expect these disclosure changes to have a material impact on our financial statements.

In July 2015, the FASB issued rules requiring entities to measure inventory within the scope of these rules at the lower of cost and net realizable value. These new rules will be effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years, and must be applied prospectively with earlier application permitted. We do not expect these new rules to have a significant impact on our financial statements.

In May 2015, the FASB issued rules to remove the requirements to categorize within the fair value hierarchy all investments for which the fair value is measured using the net asset value (NAV) per share practical expedient, as well as limiting the requirements for related disclosures. These rules will be effective for annual and interim periods beginning after December 15, 2015 with early adoption of the rules permitted. We do not expect the disclosure changes to have a significant impact on our financial statements.

In April 2015, the FASB issued rules that require debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with the presentation of debt discounts. We early adopted the new rule in the first quarter of 2015 and retrospectively reclassified unamortized debt issuance costs of $68 million at December 31, 2014. The amount was previously reflected in other assets.

ITEM 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

General

Our results are sensitive to fluctuations in oil, NGL and gas prices. We expect that in 2016 price changes at current levels of production and prices, including the impact of existing hedges, will affect our pre-tax annual income and cash flows by approximately $21 million for each $1 per barrel change in Brent oil prices. If natural gas prices varied by $0.50 per Mcf, it would have an estimated effect on our pre-tax annual income and cash flows of approximately $12 million. A $1 change in NGL prices will result in a $3 million pre-tax annual effect. 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 discussed above, we executed Brent-based crude oil hedges for 2016 using costless collars, representing annualized average production of 30,100 barrels per day and a weighted-average floor price of $50.71. Offsetting these hedges, we have calls for annualized averages of 19,300 barrels per day at a weighted-average ceiling price of $66.79 per barrel, 30,000 barrels per day at a weighted-average ceiling price of $55.68 per barrel and 23,300 barrels per day at a weighted-average ceiling price of $57.99 per barrel for our 2016, 2017 and 2018 oil production, respectively. In addition, we entered into a swap during the year for 1,000 barrels per day of our July through December 2016 crude oil production at $61.25 per barrel.

As of December 31, 2015, we had derivatives of $86 million carried at fair value, as determined from prices provided by external sources other than those actively quoted, all of which mature in 2016.

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, 2015, the substantial majority of the credit exposures related to our business was with investment grade counterparties. We believe exposure to credit-related losses related to our business at December 31, 2015 was not material and losses associated with credit risk have been insignificant for all years presented.

Concentration of Credit Risk

Through July 2014, substantially all of our products were sold through Occidental's marketing subsidiaries at market prices and were settled at the time of sale to those entities. Beginning August 2014, we began marketing our own products directly to third parties. For the years ended

December 31, 2014 and 2013, sales through Occidental subsidiaries accounted for approximately 65% and 97% of our net sales, respectively. 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 61% of our revenue. For the years ended 2014 and 2013, ConocoPhillips/Phillips 66 Company and Tesoro Refining & Marketing Company LLC each accounted for more than 10%, and collectively 45% and 42% of our revenue, respectively.

Interest Rate Risk

Prior to the Spin-off, we had no interest rate risk exposure as we did not have any debt. As of December 31, 2015, we had borrowings of $1 billion outstanding under our Term Loan Facility and approximately $739 million outstanding under our Revolving Credit Facility both of which carry variable interest rates. A one-eighth percent change in the interest rates on these outstanding borrowings under our Term Loan Facility and Revolving Credit Facility would result in an approximately $2.2 million change in annual interest expense.

The following table shows our fixed- and variable-rate debt as of December 31, 2015:

Year of Maturity	U.S. Dollar Fixed-Rate Debt	U.S. Dollar Variable-Rate Debt	Total
		(amounts in millions)	
2016	$ —	$ 100	$ 100
2017	—	100	100
2018	—	100	100
2019	—	1,439	1,439
2020	433	—	433
Thereafter	3,971	—	3,971
Total	$ 4,404	$ 1,739	$ 6,143
Weighted-average interest rate	6.83%	2.75%	5.67%
Fair Value	$ 1,895	$ 1,739	$ 3,634

FORWARD-LOOKING STATEMENTS

The information in this report includes ''forward-looking statements.'' The factors identified in this cautionary statement are important factors (but not necessarily all of the important factors) that could cause actual results to differ materially from those expressed in any forward-looking statement made by us, or on our behalf. You can typically identify ''forward-looking statements'' by the use of forward-looking words such as ''aim,'' ''anticipate,'' ''believe,'' ''budget,'' ''continue,'' ''could,'' ''effort,'' ''estimate,'' ''expect,'' ''forecast,'' ''goal,'' ''guidance,'' ''intend,'' ''likely,'' ''may,'' ''might,'' ''objective,'' ''outlook,'' ''plan,'' ''potential,'' ''predict,'' ''project,'' ''seek,'' ''should,'' ''target, ''will'' or ''would'' and other similar words that convey the prospective nature of events or outcomes generally indicate forward-looking statements. Such statements specifically include statements regarding our future financial position, liquidity, cash flows, results of operations and business prospects, budgets, drilling program, maintenance capital, future operations, hedging activities, planned capital investments, projected production, projected costs, plans and objectives of management for future operations and possible future strategic transactions. For any such forward-looking statement that includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that, while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results, sometimes materially. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading ''Risk Factors'' included in this report.

The following are important factors we have identified that could cause actual results to differ materially from those expressed in any forward-looking statement made by, or on behalf of, our company:

- commodity pricing;
- the ability of our lenders to limit our borrowing capacity;
- other constraints on liquidity such as any inability to monetize assets;
- the effect of our outstanding debt on our financial flexibility;
- limits on our ability to hedge against price decreases and the effects of hedging on our ability to benefit from price increases;
- insufficiency of our operating cash flow to fund planned capital investments;
- inability to comply with minimum listing standards;
- inability to implement our capital investment program profitably or at all;
- inability to replace reserves;
- regulations or changes in regulations and inability to comply or to obtain government permits and approvals;
- tax law changes;
- uncertainties associated with drilling for and producing oil and natural gas;
- competition for and costs of oilfield equipment, services, qualified personnel and acquisitions;
- the subjective nature of estimates of proved reserves and related future net cash flows;
- risks related to our disposition and acquisition activities;
- concentration of operations in a single geographic area;
- restrictions on our ability to obtain, use, manage or dispose of water;
- inability to drill identified locations when planned or at all;
- concerns about climate change and other air quality issues;
- catastrophic events for which we may be uninsured or underinsured;
- effects of litigation;
- cyber attacks;
- operational issues that restrict market access; and
- uncertainties related to the Spin-off and the agreements related thereto.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. Unless legally required, we undertake no responsibility to publicly release any revision of our forward-looking statements after the date they are made.

Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

To the Board of Directors and Stockholders
California Resources Corporation:

We have audited the accompanying consolidated balance sheets of California Resources Corporation and subsidiaries (the Company) as of December 31, 2015 and 2014, and the related consolidated and combined statements of operations, comprehensive income, equity and cash flows for each of the years in the three-year period ended December 31, 2015. These consolidated and combined financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated and combined financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated and combined financial statements referred to above present fairly, in all material respects, the financial position of California Resources Corporation and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2015 in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), California Resources Corporation's internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control—Integrated Framework issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 29, 2016 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Los Angeles, California
February 29, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Board of Directors and Stockholders
California Resources Corporation:

We have audited California Resources Corporation's (the Company) internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control—Integrated Framework issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). California Resources Corporation's management is responsible 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 internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit 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 audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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.

In our opinion, California Resources Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control—Integrated Framework issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of California Resources Corporation and subsidiaries as of December 31, 2015 and 2014, and the related consolidated and combined statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2015, and our report dated February 29, 2016 expressed an unqualified opinion on those consolidated and combined financial statements.

/s/ KPMG LLP

Los Angeles, California
February 29, 2016

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets
As of December 31, 2015 and 2014
(in millions)

	2015	2014
CURRENT ASSETS		
Cash and cash equivalents	$ 12	$ 14
Trade receivables, net	200	308
Inventories	58	71
Other current assets	227	308
Total current assets	497	701
PROPERTY, PLANT AND EQUIPMENT	20,996	20,536
Accumulated depreciation, depletion and amortization	(14,684)	(8,851)
	6,312	11,685
OTHER ASSETS	244	43
TOTAL ASSETS	$ 7,053	$ 12,429
CURRENT LIABILITIES		
Current maturities of long-term debt	$ 100	$ —
Accounts payable	257	588
Accrued liabilities	222	334
Current income taxes	26	—
Total current liabilities	605	922
LONG-TERM DEBT—PRINCIPAL AMOUNT	6,043	6,360
DEFERRED GAIN AND ISSUANCE COSTS, NET	491	(68)
DEFERRED INCOME TAXES	—	2,055
OTHER LONG-TERM LIABILITIES	830	549
COMMITMENTS AND CONTINGENCIES		
EQUITY		
Preferred stock—no shares outstanding at December 31, 2015 or 2014 (200 million shares authorized at $0.01 par value)		
Common stock (2.0 billion shares authorized at $0.01 par value) Outstanding shares (2015—388,180,479 shares and 2014—385,639,582 shares)	4	4
Additional paid-in capital	4,778	4,748
Accumulated deficit	(5,683)	(2,117)
Accumulated other comprehensive income (loss)	(15)	(24)
Total equity	(916)	2,611
TOTAL LIABILITIES AND EQUITY	$ 7,053	$ 12,429

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated and Combined Statements of Operations
For the years ended December 31, 2015, 2014 and 2013
(in millions)

	2015	2014	2013
REVENUES			
Oil and natural gas sales to third parties	$ 2,294	$ 1,406	$ 85
Oil and natural gas sales to related parties	—	2,617	4,054
Other revenue	109	150	145
	2,403	4,173	4,284
COSTS AND OTHER DEDUCTIONS			
Production costs	951	1,057	986
General and administrative expenses	354	302	266
Depreciation, depletion and amortization	1,004	1,198	1,144
Asset impairments	4,852	3,402	—
Taxes other than on income	180	217	185
Exploration expense	36	139	116
Interest and debt expense, net	326	72	—
Other expenses	176	207	140
	7,879	6,594	2,837
INCOME / (LOSS) BEFORE INCOME TAXES	(5,476)	(2,421)	1,447
Income tax (expense) / benefit	1,922	987	(578)
NET INCOME / (LOSS)	$ (3,554)	$ (1,434)	$ 869
Net income / (loss) per share of common stock			
Basic	$ (9.27)	$ (3.75)	$ 2.24
Diluted	$ (9.27)	$ (3.75)	$ 2.24
Dividends per common share	$ 0.03	$ —	$ —

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated and Combined Statements of Comprehensive Income
For the years ended December 31, 2015, 2014 and 2013
(in millions)

	2015	2014	2013
Net income / (loss)	$ (3,554)	$ (1,434)	$ 869
Other comprehensive income (loss) items:			
Unrealized (losses) gains on derivatives[a]	—	(2)	(2)
Pension and postretirement (losses) gains[b]	(2)	(1)	27
Reclassification to income of realized losses (gains) on derivatives[c]	—	3	(2)
Reclassification to income of realized losses (gains) on pensions[d]	11	—	—
Other comprehensive income, net of tax	9	—	23
Comprehensive income / (loss)	$ (3,545)	$ (1,434)	$ 892

(a) Net of tax of zero, $1 and $1 in 2015, 2014, and 2013, respectively.
(b) Net of tax of $1, $1 and $(16) in 2015, 2014 and 2013, respectively. See Note 14, Retirement and Postretirement Benefit Plans, for additional information.
(c) Net of tax of zero, $(2) and $1 in 2015, 2014 and 2013, respectively.
(d) Net of tax of $(7) for 2015 and zero for 2014 and 2013, respectively. See Note 14, Retirement and Postretirement Benefit Plans, for additional information.

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated and Combined Statements of Equity
For the years ended December 31, 2015, 2014 and 2013
(in millions)

	Common Stock	Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Net Parent Company Investment	Total Equity/Net Investment
Balance, December 31, 2012	$ —	$ —	$ —	$ (47)	$ 9,907	$ 9,860
Net income / (loss)	—	—	—	—	869	869
Other comprehensive income, net of tax	—	—	—	23	—	23
Net distributions to Occidental	—	—	—	—	(763)	(763)
Balance, December 31, 2013	$ —	$ —	$ —	$ (24)	$ 10,013	$ 9,989
Net income / (loss)[(a)]	—	—	(2,117)	—	683	(1,434)
Net contributions from Occidental[(b)]	—	—	—	—	56	56
Dividend to Occidental	—	—	—	—	(6,000)	(6,000)
Issuance of common stock at Spin-off	4	—	—	—	(4)	—
Reclassification of net parent company investment to additional paid-in capital	—	4,748	—	—	(4,748)	—
Balance, December 31, 2014	$ 4	$ 4,748	$ (2,117)	$ (24)	$ —	$ 2,611
Net income / (loss)	—	—	(3,554)	—	—	(3,554)
Other comprehensive income, net of tax	—	—	—	9	—	9
Dividends on common stock	—	—	(12)	—	—	(12)
Issuance of common stock and other, net	—	30	—	—	—	30
Balance, December 31, 2015	$ 4	$ 4,778	$ (5,683)	$ (15)	$ —	$ (916)

(a) Net income of $683 million related to operations from January 1, 2014 through the spin-off date of November 30, 2014 was included in Net Parent Company Investment. The net loss of $2,117 million for the month ended December 31, 2014 reflected our accumulated deficit as of that date as a stand-alone company.

(b) Net contributions from Occidental include non-cash contributions of approximately $400 million, predominantly trade receivables, partially offset by $335 million in cash distributions to Occidental.

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated and Combined Statements of Cash Flows
For the years ended December 31, 2015, 2014 and 2013
(in millions)

	2015	2014	2013
CASH FLOW FROM OPERATING ACTIVITIES			
Net income / (loss)	$ (3,554)	$ (1,434)	$ 869
Adjustments to reconcile net income / (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,004	1,198	1,144
Asset impairments	4,852	3,402	—
Deferred income tax expense / (benefit)	(2,258)	(1,152)	260
Other noncash tax provision	310	—	—
Other noncash charges to income, net	187	113	29
Dry hole expenses	9	101	72
Changes in operating assets and liabilities, net:			
(Increase) decrease in receivables, net	47	146	(8)
(Increase) decrease in inventories	—	2	8
(Increase) decrease in other current assets	18	(133)	2
Increase (decrease) in accounts payable and accrued liabilities	(212)	128	100
Net cash provided by operating activities	403	2,371	2,476
CASH FLOW FROM INVESTING ACTIVITIES			
Capital investments	(401)	(2,089)	(1,669)
Changes in capital investment accruals	(205)	69	—
Acquisitions and other	(151)	(292)	(44)
Net cash used by investing activities	(757)	(2,312)	(1,713)
CASH FLOW FROM FINANCING ACTIVITIES			
Proceeds from revolving credit facility	2,035	515	—
Repayments of revolving credit facility	(1,656)	(155)	—
Issuance of senior notes	—	5,000	—
Issuance of term loan	—	1,000	—
Debt issuance costs	—	(70)	
Debt repurchase and amendment costs	(23)	—	—
Issuance of common stock	8	—	—
Cash dividends paid	(12)	—	—
(Distributions to) contributions from Occidental, net	—	(335)	(763)
Dividends to Occidental	—	(6,000)	—
Net cash provided (used) by financing activities	352	(45)	(763)
(Decrease) increase in cash and cash equivalents	(2)	14	—
Cash and cash equivalents—beginning of year	14	—	—
Cash and cash equivalents—end of year	$ 12	$ 14	$ —

The accompanying notes are an integral part of these consolidated and combined 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 exclusively within the State of 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 the spin-off on November 30, 2014 (the Spin-off). Prior to the Spin-off, all material existing assets, operations and liabilities of the California business were consolidated under us. On November 30, 2014, Occidental distributed shares of our common stock on a pro rata basis to Occidental stockholders and we became an independent, publicly traded company. Occidental retained approximately 18.5% of our outstanding shares of common stock which it has stated it intends to divest 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

Until the Spin-off, the accompanying financial statements were derived from the consolidated financial statements and accounting records of Occidental and were presented on a combined basis for the pre-Spin-off periods. These financial statements reflect the historical results of operations, financial position and cash flows of the California business. All financial information presented after the Spin-off consists of the stand-alone consolidated results of operations, financial position and cash flows of CRC. 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.

The statements of operations for periods prior to the Spin-off include expense allocations for certain corporate functions and centrally-located activities historically performed by Occidental. These functions include executive oversight, accounting, treasury, tax, financial reporting, finance, internal audit, legal, risk management, information technology, government relations, public relations, investor relations, human resources, procurement, engineering, drilling, exploration, marketing, ethics and compliance, and certain other shared services. These allocations were based primarily on specific identification of time or activities associated with us, employee headcount or our relative size compared to Occidental. Our management believes the assumptions underlying the financial statements, including the assumptions regarding allocating expenses from Occidental, are reasonable. However, the financial statements for the pre-Spin-off periods may not include all of the actual expenses that would have been incurred, may include duplicative costs and may not reflect our results of operations, financial position and cash flows had we operated as a stand-alone public company during the periods presented. Actual costs that would have been incurred if we had been a stand-alone company prior to the Spin-off would depend on multiple factors, including organizational structure and strategic and operating decisions.

The assets and liabilities in the consolidated and combined financial statements are presented on a historical cost basis. We have eliminated all of our significant intercompany transactions and accounts. Prior to the Spin-off, we participated in Occidental's centralized treasury management program and had not incurred any debt. Additionally, excess cash generated by our business was distributed to Occidental, and likewise our cash needs were provided by Occidental, in the form of contributions.

All financial information represents the financial position, results of operations and cash flows of CRC, as follows:

- Our consolidated statements of operations, comprehensive income, cash flows, and changes in equity for the year ended December 31, 2015 consist of the stand-alone consolidated results of CRC post Spin-off.
- Our consolidated and combined statements of operations, comprehensive income and cash flows for the year ended December 31, 2014 consist of the consolidated results for the month ended December 31, 2014 and the combined results of the California business prior to the Spin-off. Our statements of income, comprehensive income and cash flows for the years ended December 31, 2013 and 2012 consist entirely of the combined results of the California business.
- Our consolidated balance sheets at December 31, 2015 and 2014 consist of the consolidated balances of CRC post Spin-off.
- Our consolidated and combined statement of changes in equity for the year ended December 31, 2014 consists of both the California business prior to the Spin-off and the consolidated activity for CRC subsequent to the Spin-off. Our statements of changes in equity for the years ended December 31, 2013 and 2012 consists entirely of the combined activity of the California business.

Had we been a stand-alone company for the full year 2014, and had the same level of debt throughout the year as we did on December 31, 2014, of approximately $6.4 billion, we would have incurred $314 million of interest expense, on a pro-forma basis, for the year ended December 31, 2014, compared to the $72 million pre-tax interest expense reported in our statement of operations for the year then ended.

Certain prior year amounts have been reclassified to conform to the 2015 presentation. In 2015, we changed the classification of certain employee-related costs between general and administrative expenses and production costs to better align these costs with the functions performed by those employees. Prior period amounts have been changed to conform to the current year classification.

Risks and Uncertainties

The process of preparing financial statements in conformity with United States generally accepted accounting principles requires management to 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.

Revenue Recognition

We recognize revenue from oil and natural gas production when 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.

Net Parent Company Investment

Prior to the Spin-off, our balance sheets included net parent company investment, which represented Occidental's historical investment in us, our accumulated net income and the net effect of transactions with, and allocations from, Occidental.

Inventories

Materials and supplies are valued at weighted-average cost and are reviewed periodically for obsolescence. Finished goods include oil and natural gas products, which are valued at the lower of cost or market.

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, 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.

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 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.

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

	2015	2014	2013
		(in millions)	
Balance—Beginning of Year	$ 4	$ 18	$ 18
Additions to capitalized exploratory well costs pending the determination of proved reserves	16	3	46
Reclassification to property, plant and equipment based on the determination of proved reserves	(5)	(8)	(31)
Capitalized exploratory well costs charged to expense	(9)	(9)	(15)
Balance—End of Year	$ 6	$ 4	$ 18

We expense annual lease rentals, the costs of injection used in production and exploration geological, geophysical and seismic costs as incurred. Cost 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.

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 capitalized development and successful exploration costs over proved developed reserves. Substantially all of our total depreciation, depletion and amortization expense relates to production costs.

Proved oil and gas reserves and production volumes are used as the basis for recording depreciation and depletion of oil and gas properties. 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.

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.

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, 2015, the net capitalized costs attributable to unproved properties were approximately $300 million. 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. 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 timing of any write-downs of these 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.

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. 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 acreage.

At year end 2014, we performed impairment tests with respect to our proved and unproved properties as a result of significant declines in oil prices largely during the last half of 2014. As a result, in the fourth quarter of 2014, we recorded pre-tax asset impairment charges of $3.4 billion on certain proved and unproved properties throughout our asset base. Approximately $650 million of the charge was related to unproved properties.

We evaluate 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 current environment.

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 to 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 depreciated over the useful life of the asset.

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 the asset retirement obligation, of which $343 million and $397 million is included in other long-term liabilities, with the remaining current portion in accrued liabilities at December 31, 2015 and 2014, respectively.

	For the years ended December 31, 2015	For the years ended December 31, 2014
	(in millions)	
Beginning balance	$ 415	$ 415
Liabilities incurred—capitalized to PP&E	7	19
Liabilities settled and paid	(18)	(29)
Accretion expense	20	22
Acquisitions, disposition and other—changes in PP&E	—	22
Revisions to estimated cash flows—changes in PP&E	(67)	(34)
Ending balance	$ 357	$ 415

Derivative Instruments

All of our current 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 in earnings in the current period and are reported on a net basis in the 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 11. A summary of our accounting policy for awards issued under our plans is as follows.

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, the volatility factor is 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 (U.S. Treasury Strip) T-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. Estimates of fair value are not intended to, and may not, accurately predict the value ultimately realized by employees who receive the awards, and the ultimate value may not be indicative of the reasonableness of the original estimates of fair value made by us.

The performance targets under the 2015 Performance Stock Unit (PSU) awards are based 50% on achievement of specified VCI results and 50% on total shareholder return (TSR) relative to a selected peer group of companies over specified multi-year performance periods. The fair values of the VCI-based portions of the PSU awards are initially determined on the grant date based on an estimated performance achievement at the target level, and subsequently adjusted, as applicable, based on the VCI results. The fair values of the TSR-based portions of the PSUs are initially determined on the grant date, and subsequently for cash-settled awards, 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. 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 Strip) T-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. Estimates of fair value are not intended to and may not accurately predict the value ultimately realized by the employees who receive the awards, and the ultimate value may not be indicative of the reasonableness of the original estimates of fair value made by us.

For cash- and stock-settled restricted stock units (RSU), compensation value is initially measured on the grant date using the quoted market price of our common stock. Compensation expense for RSU and PSU awards is recognized on a straight-line basis over the requisite service periods, adjusted for estimated forfeitures. Compensation expense for the cash-settled portion of the awards is adjusted cumulatively for changes in the value of the underlying stock on a quarterly basis. For PSU awards, compensation expense for the cash-settled portion of the awards and related dividends is also 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. All such performance or stock-price-related changes are recognized in periodic compensation expense. The stock-settled portion of these awards is expensed using the initially measured compensation value.

Earnings Per Share

Our instruments containing rights to nonforfeitable dividends granted in stock-based awards are considered participating securities prior to vesting and, therefore, have been deducted from earnings in computing basic and diluted earnings per share (EPS) under the two-class method.

Basic EPS was computed by dividing net income attributable to common stock, net of income allocated to participating securities, by the weighted-average number of common shares outstanding during each period, net of treasury shares, if any, and including vested but unissued shares and share units. The computation of diluted EPS reflects the additional dilutive effect of stock options and unvested stock awards.

We compute EPS using the two-class method required for participating securities. Undistributed earnings allocated to participating securities are subtracted from net income in determining net income attributable to common stockholders. Restricted stock awards are considered participating securities because holders of such shares have non-forfeitable dividend rights in the event of our declaration of a dividend for common shares.

The denominator of basic EPS is the sum of the daily weighted-average number of common shares outstanding during the periods presented and vested stock awards that have not yet been issued as common stock. The denominator of diluted EPS is based on the basic shares outstanding, adjusted for the effect of outstanding option awards, to the extent they are dilutive.

Retirement and Postretirement Benefit Plans

Prior to the Spin-off, a majority of our employees participated in postretirement benefit plans sponsored by Occidental, which included participants from other Occidental subsidiaries. These plans had an insignificant amount of assets and were substantially funded as benefits were paid. We recognized a liability in the accompanying balance sheets for the employees of the California operations. The related postretirement expenses were allocated to us from Occidental based on the employees of the California business. Following the Spin-off, all of our employees participate in postretirement benefit plans sponsored by us. These plans are funded as benefits are paid.

For defined benefit pension and postretirement plans that are 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. Common stock, preferred stock, publicly registered mutual funds, U.S. government securities and corporate bonds are valued using quoted market prices in active markets when available. When quoted market prices are not available, these investments are valued using pricing models with observable inputs from both active and non-active markets. Common and collective trusts are valued at the fund units' net asset value (NAV) provided by the issuer, which represents the quoted price in a non-active market. Short-term investment funds are valued at the fund units' NAV provided by the issuer.

Actuarial gains and losses that have not yet been recognized through income are recorded in accumulated OCI 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 and discounts those 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.

Income Taxes

Until the Spin-off, our taxable income was historically included in the consolidated U.S. federal income tax returns of Occidental and in a number of their consolidated state income tax returns. In the accompanying financial statements, our provision for income taxes through the Spin-off is computed as if we were a stand-alone tax-paying entity.

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 recorded 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.

Other Current Assets

Other current assets at December 31, 2015 included amounts due from joint interest partners of approximately $40 million, net deferred tax assets of approximately $59 million, and $87 million in derivatives from commodities contracts. At December 31, 2014 other current assets included amounts due from joint interest partners of approximately $120 million, greenhouse gas emission assets of $65 million and deferred tax assets of $61 million.

Other Assets

Other assets at December 31, 2015 included $199 million of net deferred tax assets.

Accrued Liabilities

Accrued liabilities at December 31, 2015 included accrued employee-related costs of approximately $105 million and interest payable of approximately $40 million. At December 31, 2014 accrued liabilities included accrued employee-related costs of approximately $95 million, interest payable of approximately $70 million, and greenhouse gas emission liabilities of approximately $65 million.

Supplemental Cash Flow Information

We have not made United States federal and state income tax payments in 2015 due to the taxable loss we incurred. Up until the Spin-off, our share of Occidental's tax payments or refunds were paid or received, as applicable, by our parent. Such amounts paid on our behalf during the years ended December 31, 2014 and 2013 were approximately $165 million and $318 million, respectively. We also paid taxes other than on income, consisting mostly of property taxes, of approximately $154 million, $183 million and $185 million during the years ended December 31, 2015, 2014 and 2013, respectively. Interest paid totaled approximately $359 million, $3 million and zero, respectively, for the years ended December 31, 2015, 2014 and 2013.

In 2014, Occidental transferred to us certain assets, liabilities and accruals, of which the most significant consisted of outstanding trade receivables of approximately $400 million. These non-cash transfers and the corresponding net contribution to us from Occidental were excluded from net cash provided by operating activities and cash flow from financing activities.

Major Customers

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 61% of our revenue. For the years ended 2014 and 2013, ConocoPhillips/Phillips 66 Company and Tesoro Refining & Marketing Company LLC each accounted for more than 10%, and collectively 45% and 42% of our revenue, respectively.

NOTE 2 ACCOUNTING AND DISCLOSURE CHANGES

Recently Issued and Adopted Accounting and Disclosure Changes

In November 2015, the Financial Accounting Standards Board (FASB) issued rules requiring that deferred income tax liabilities and assets be classified as noncurrent in a classified balance sheet. These new rules will be effective for annual and interim periods beginning after December 15, 2016 and can be applied either retrospectively or prospectively with earlier application permitted. While we are evaluating any potential impact of these rules, we currently believe the effect of the new rules will not have a material impact on our financial statements.

In September 2015, the FASB issued rules that require an acquirer in a business combination account for measurement-period adjustments during the period in which it determines the amount of the adjustment, rather than retrospectively. These new rules will be effective for annual and interim periods beginning after December 15, 2015 and must be applied prospectively. We do not expect these new rules to have a material impact on our financial statements.

In August 2015, the FASB issued rules to defer the effective date of its new revenue recognition rules to annual and interim reporting periods beginning after December 15, 2017. Earlier application is permitted only as of annual and interim reporting periods beginning after December 15, 2016. While we are evaluating any potential impact of these rules, we currently believe the effect of the new rules will not have a material impact on our financial statements.

In July 2015, the FASB issued rules to simplify the accounting for employee benefit plans by removing the requirement for plan investments to be disaggregated by class. Under the new guidance, a plan will disaggregate its investments measured using fair value only by general type (e.g., common stocks, corporate bonds, mutual funds). These new rules will be effective for fiscal years beginning after December 15, 2015 and must be applied retrospectively with earlier application permitted. We do not expect these disclosure changes to have a material impact on our financial statements.

In July 2015, the FASB issued rules requiring entities to measure inventory at the lower of cost and net realizable value. These new rules will be effective for annual and interim periods beginning after December 15, 2016 and must be applied prospectively with earlier application permitted. We do not expect these new rules to have a material impact on our financial statements.

In May 2015, the FASB issued rules to remove the requirements to categorize within the fair value hierarchy all investments for which the fair value is measured using the NAV per share practical expedient, as well as limiting the requirements for related disclosures. These rules will be effective for annual and interim periods beginning after December 15, 2015 with early adoption of the rules permitted. We do not expect the disclosure changes to have a significant impact on our financial statements.

In April 2015, the FASB issued rules that require debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with the presentation of debt discounts. We early adopted the new rule in the first quarter of 2015 and retrospectively reclassified unamortized debt issuance costs of $68 million at December 31, 2014. The amount was previously reflected in other assets.

NOTE 3 ACQUISITIONS

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. Our asset acquisition and disposition program contemplates transactions designed to upgrade our portfolio on a cash neutral basis.

2014

During the year ended December 31, 2014, we paid approximately $290 million to acquire certain producing and non-producing oil and gas properties, including oil and gas properties in the Ventura basin purchased for approximately $200 million in the fourth quarter of 2014.

2013

During the year ended December 31, 2013, we paid approximately $50 million to acquire certain oil and gas properties, including an acquisition in the San Joaquin basin, which obligates us to invest at least $250 million on exploration and development activities over a period of five years from the date of acquisition. We currently plan to invest this amount during that period. Any deficiency in meeting this capital investment obligation would need to be paid in cash at the end of the five-year period. Through December 31, 2015, we have already fulfilled approximately 30% of this obligation.

NOTE 4 INVENTORIES

Inventories consisted of the following:

	Balance at December 31,	
	2015	**2014**
	(in millions)	
Materials and supplies	$ 55	$ 66
Finished goods	3	5
Total	$ 58	$ 71

NOTE 5 DEBT

Debt consisted of the following:

	December 31, 2015	December 31, 2014
	(in millions)	
Secured First Lien Bank Debt		
Revolving Credit Facility	$ 739	$ 360
Term Loan Facility	1,000	1,000
Senior Secured Second Lien Notes		
8% Notes Due 2022	2,250	—
Senior Unsecured Notes		
5% Notes Due 2020	433	1,000
5½% Notes Due 2021	829	1,750
6% Notes Due 2024	892	2,250
Total Debt—Principal Amount	6,143	6,360
Less Current Maturities of Long-Term Debt	(100)	—
Long-Term Debt—Principal Amount	$ 6,043	$ 6,360

At December 31, 2015 deferred gain and issuance costs, net, of $491 million consisted of $560 million of deferred gains offset by $69 million of deferred issuance costs. The December 31, 2014 balance of $68 million consisted of deferred issuance costs.

Credit Facilities

We have a credit agreement effective through September 2019 that provides for (i) a senior term loan facility (the Term Loan Facility) and (ii) a senior revolving loan facility (the Revolving Credit Facility and, together with the Term Loan Facility, the Credit Facilities). All borrowings under these facilities are subject to certain customary conditions. We amended the Credit Facilities effective as of November 2015 and February 2016, to change certain of our financial and other covenants, incurring costs of $11 million and $8 million, respectively. During the third quarter of 2015, our corporate ratings from Moody's Investors Service (Moody's) and Standard & Poor's Ratings Services (S&P) were downgraded, resulting in the imposition under our Credit Facilities of a borrowing base and the requirement to grant security on a first-lien basis. On February 23, 2016, we received 100% bank approval to amend our Credit Facilities. Effective with the amendment, the borrowing base under our Credit Facilities was reduced to $2.3 billion and the lenders' revolving facility commitments were reduced to $1.6 billion.

The Revolving Credit Facility includes a sub-limit of $400 million for the issuance of letters of credit. We are required to repay the Term Loan Facility in $25 million quarterly installments beginning on March 31, 2016. As of December 31, 2015, we had $739 million outstanding borrowings under our Revolving Credit Facility and $1.0 billion under the Term Loan Facility.

Borrowings under the Credit Facilities bear interest, at our election, at either a LIBOR rate or an alternate base rate (ABR) (equal to the greatest of (i) the administrative agent's prime rate, (ii) the one-month LIBOR rate plus 1.00% and (iii) the federal funds effective rate plus 0.50%), in each case plus an applicable margin. This applicable margin is based, while our total leverage ratio exceeds 3.00:1.00, on our borrowing base utilization and effective February 2016 will vary from (a) in the case of LIBOR loans, 2.50% to 3.50% and (b) in the case of ABR loans, 1.50% to 2.50%. The unused portion of the Revolving Credit Facility, as it may be limited by the borrowing base, is subject to a commitment fee equal to 0.50% per annum. We also pay customary fees and expenses under the Credit Facilities. 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.

As amended, our financial performance covenants through December 31, 2016 comprise an obligation to achieve (i) a cumulative minimum EBITDAX during 2016 of $55 million through the first quarter, $130 million through the second quarter, $190 million through the third quarter and $250 million through the fourth quarter and (ii) a trailing twelve-month minimum interest coverage ratio of 2.00:1.00 as of the end of the first quarter, 1.50:1.00 as of the end of the second quarter, 1.25:1.00 as of the end of the third quarter and 0.70:1.00 as of the end of the fourth quarter. As of the end of the first quarter of 2017, the minimum interest coverage ratio will revert back to 2.00:1.00. We will not be subject to a maximum first lien senior secured leverage ratio for 2016. The amendment also suspends the requirement for us to comply with a trailing twelve-month maximum first lien senior secured leverage ratio of 2.25:1.00 until the end of the first quarter of 2017.

Except as otherwise agreed with our lenders for specific transactions, our Credit Facilities as amended require us to apply 100% of the proceeds from certain asset monetizations to repay loans outstanding under the Credit Facilities, except that we will be permitted to use up to 40% of proceeds from non-borrowing base asset sales to repurchase our notes to the extent available at a significant minimum discount to par, as specified in the amended facilities. Subject to compliance with our indentures, our amended facilities permit us to incur additional indebtedness to repurchase our notes to the extent available at a significant minimum discount to par, as specified in the amended facilities, as follows: (i) up to $1 billion, which may be secured by liens that are junior to the liens securing our Credit Facilities, provided that at least 60% of the proceeds from the new debt is used first to repay loans outstanding under the Credit Facilities, and (ii) up to $200 million, which may be secured by first-priority liens on our non-borrowing base properties. The amended Credit Facilities also permit us to incur up to an additional $50 million of non-Credit Facility indebtedness, which, subject to compliance with our indentures, may be secured; and the proceeds of which must be applied to repay loans outstanding under the Credit Facilities. All of the foregoing prepayments will be applied first to our Term Loan Facility and second to our Revolving Credit Facility after the Term Loan Facility has been fully repaid (with a corresponding reduction to the lenders' Revolving Credit Facility commitments). Our amended facilities also require us to apply cash on hand in excess of $150 million to repay amounts outstanding under our Revolving Credit Facility. Further, we are restricted from (i) paying dividends or making other distributions to common stockholders and (ii) making capital investments exceeding $100 million during 2016.

The amendment also imposed a semi-annual borrowing base redetermination each May 1 and November 1, commencing May 1, 2016. The borrowing base will be based upon a number of factors, including commodity prices and reserves levels. Increases in our borrowing base requires approval of at least 80% of our revolving lenders, as measured by exposure, while decreases require a two-thirds approval. We and the lenders (requiring a request from the lenders holding ⅔ of the revolving commitments and outstanding loans), 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.

Effective February 2016, all obligations under the Credit Facilities are guaranteed jointly and severally by all of our material wholly-owned material subsidiaries. The assets and liabilities of subsidiaries not guaranteeing the debt are de minimis.

Substantially all of the restrictions imposed by the recent amendment to the Credit Facilities, other than the requirement for semiannual borrowing base redeterminations, may terminate in the future if we are able to comply with the financial covenants as they existed prior to giving effect to the amendment. If we were to breach any of our Credit Facility covenants, our lenders would be permitted to accelerate the principal amount due under the Credit Facilities and foreclose on the assets securing the facilities. If payment were accelerated under our Credit Facilities, it would result in a default under our outstanding notes and permit acceleration and foreclosure on the assets securing the secured notes.

At December 31, 2015, we were in compliance with the financial and other covenants under our Credit Facilities as they existed at that time.

Senior Notes

On October 1, 2014, we issued $5.00 billion in aggregate principal amount of our senior unsecured notes, including $1.00 billion of 5% senior unsecured notes due January 15, 2020 (the 2020 notes), $1.75 billion of 5½% senior unsecured notes due September 15, 2021 (the 2021 notes) and $2.25 billion of 6% senior unsecured notes due November 15, 2024 (the 2024 notes and together with the 2020 notes and the 2021 notes, the unsecured notes). The unsecured notes were issued at par and are fully and unconditionally guaranteed on a senior unsecured basis by all of our material subsidiaries. We used the net proceeds from the issuance of the unsecured notes to make a $4.95 billion cash distribution to Occidental in October 2014.

In December 2015, we exchanged $534 million, $921 million and $1,358 million in aggregate principal amount of the 2020 notes, the 2021 notes, and the 2024 notes, respectively, for $2.25 billion in aggregate principal amount of newly issued 8% senior secured second lien notes due December 15, 2022 (the 2022 notes). We recorded a deferred gain of approximately $560 million on the debt exchange, which will be amortized using the effective interest rate method over the term of the 2022 notes. Additionally, we incurred approximately $28 million in third-party costs which were fully expensed in 2015. The newly-issued second lien notes are secured on a second-priority basis, subject to the terms of an intercreditor agreement and collateral trust agreement by a lien on the same collateral used to secure our obligations under our Credit Facilities.

In December 2015, we repurchased approximately $33 million in principal amount of the 2020 notes for $12 million in cash.

We will pay interest semiannually in cash in arrears on January 15 and July 15 for the 2020 notes, on March 15 and September 15 for the 2021 notes and on May 15 and November 15 for the 2024 notes. We will pay interest on the 2022 notes semiannually in cash in arrears on June 15 and December 15, beginning on June 15, 2016.

The indentures governing the senior unsecured notes and the second lien secured notes each include covenants that, among other things, limit our and our restricted subsidiaries' ability to incur debt secured by liens. The indentures also restrict our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. These covenants are subject to a number of important qualifications and limitations that are set forth in the indenture. 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 indentures) with respect to a series of notes, we will be required, unless we have exercised our right to redeem the notes of such series, to offer to purchase the notes of such series at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest. The indenture governing our second-lien secured notes also restricts our ability to sell certain assets and to release collateral from liens securing the second-lien secured notes.

Principal maturities of long-term debt outstanding at December 31, 2015 are as follows (in millions):

2016	$ 100
2017	100
2018	100
2019	1,439
2020	433
Thereafter	3,971
Total	$ 6,143

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, 2015 and 2014, including the fair value of the variable rate portion, which we believe approximates the carrying value, was approximately $3.6 billion and $5.6 billion, respectively, compared to a carrying value of approximately $6.1 billion and $6.4 billion. A one-eighth percent change in the variable interest rates on the borrowings under our Term Loan Facility and Revolving Credit Facility on December 31, 2015, would result in a $2.2 million change in annual interest expense. In 2014, we incurred $70 million in debt issuance costs related to the notes and the Credit Facility which we are amortizing using the effective interest rate method over the respective term of each instrument.

As of December 31, 2015 and 2014, we had letters of credit in the aggregate amount of approximately $70 million (including $49 million under the Revolving Credit Facility) and $25 million, respectively, which were issued to support ordinary course marketing, regulatory and other matters.

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, 2015, 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)
2016	$ 13
2017	16
2018	15
2019	14
2020	9
Thereafter	58
Total minimum lease payments	$ 125

Rental expense for operating leases was $11 million in 2015, $10 million in 2014 and $11 million in 2013.

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. Reserves balances at December 31, 2015 and 2014 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. At December 31, 2015, total purchase obligations on a discounted basis were approximately $346 million, which included approximately $67 million, $51 million, $184 million, $27 million and $7 million that will be paid in 2016, 2017, 2018, 2019 and 2020, respectively. Of the 2016 amount, a substantial majority consists of payments due for transportation commitments in the ordinary course of business and rigs that were idled in 2014. Also included in the purchase obligations are commitments for major fixed and determinable capital investments, which were approximately $7 million during 2016 and $183 million thereafter.

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, 2015, we are not aware of material indemnity claims pending or threatened against the Company.

NOTE 8 DERIVATIVES

As part of our hedging program, we entered into a number of costless collars during the year which resulted in our hedge positions as of December 31, 2015 as follows:

- Brent-based puts for our first half 2016 oil production of 30,500 barrels per day with a weighted-average floor price of $52.38 per barrel and 3,000 barrels for the second half 2016 at $50.00 per barrel.

- Brent-based calls for our first half 2016 oil production of 35,500 barrels per day at a weighted-average ceiling price of $66.15 per barrel and 3,000 barrels for the second half 2016 at $74.42 per barrel.

In addition, we entered into a Brent-based swap during the year for 1,000 barrels per day of our July through December 2016 crude oil production at $61.25 per barrel.

Subsequent to December 31, 2015 we executed additional costless collars resulting in our current Brent-based crude oil hedge positions as follows:

	Q1 2016	Q2 2016	Q3 2016	Q4 2016	2017	2018
Calls						
Barrels per Day	35,500	35,500	3,000	3,000	30,000	23,300
Wtd Avg Ceiling Price per Barrel	$ 66.15	$ 66.15	$ 74.42	$ 74.42	$ 55.68	$ 57.99
Puts						
Barrels per Day	33,800	55,500	28,000	3,000	—	—
Wtd Avg Floor Price per Barrel	$ 51.75	$ 50.14	$ 50.65	$ 50.00	$ —	$ —
Swap						
Barrels per Day	—	—	1,000	1,000	—	—
Weighted-Average Price per Barrel	$ —	$ —	$ 61.25	$ 61.25	$ —	$ —

For our third and fourth quarter 2015 natural gas production, we had hedged 40,000 million British thermal units (MMBtu) per day at an average index-based price of $3.01 per MMBtu and 20,000 MMBtu per day at weighted-average floors and ceilings of $2.80 and $3.17 per MMBtu, respectively. The initial value of these hedges was not material.

For our fourth quarter 2015 oil production, we had hedged 40,000 barrels per day at weighted-average Brent-based floors and ceilings of $61.25 and $73.88 per barrel, respectively. For our third quarter 2015 oil production, we had hedged 70,000 barrels per day at weighted-average Brent-based floors of $52.14 per barrel and 30,000 barrels per day at Brent-based ceilings of $72.12 per barrel. The initial value of our third and fourth quarter 2015 oil hedges was not material.

From January through June 2015 we had purchased options for 100,000 barrels of our crude oil production per day, at $50 per barrel Brent and sold options for 30,000 barrels per day for March through June 2015 at $75 per barrel Brent. The initial intrinsic and time values were deferred and subsequent changes were included in the net derivative losses reported in net sales. The initial intrinsic value, which was accounted for as a cash flow hedge, was insignificant.

For the first quarter of 2014 we had hedged 50 MMcf per day of our natural gas production, which qualified as cash-flow hedges. The weighted-average strike price of these swaps was $4.30 per Mcf.

We will continue to be strategic and opportunistic in implementing our hedging program. Our objective is to protect against the cyclical nature of commodity prices to protect our cash flows, margins and capital investment program and improve our ability to comply with our credit facility covenants in case of further price deterioration.

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 years ended December 31, 2015, 2014 and 2013, and the ending AOCI balances for each period were not material. For the year ended December 31, 2015, we recognized approximately $52 million of non-cash derivative gains from marking these contracts to market, which were included in revenues. The amount of the ineffective portion of cash-flow hedges was immaterial for the years ended December 31, 2014 and 2013. Refer to Note 1 for our accounting policy on derivatives.

There were no fair value hedges as of and during the years ended December 31, 2015, 2014 and 2013.

Fair Value of Derivatives

Our commodity derivatives are measured at fair value using industry-standard models with various inputs, including quoted forward prices. The initial gross and net fair value of our 2014 put options was approximately $24 million, which approximated the time value of the instruments, and was included in other current assets as of December 31, 2014.

The following table presents the gross and net fair values of our outstanding derivatives as of December 31, 2015 (in millions):

December 31, 2015	Asset Derivatives Balance Sheet Location	Fair Value	Liability Derivatives Balance Sheet Location	Fair Value
Commodity contracts	Other current assets	$ 87	Accrued Liabilities	$ (1)
Total gross and net fair value		$ 87		$ (1)

NOTE 9 FAIR VALUE MEASUREMENTS

Fair Values—Recurring

The following tables present assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2015 and 2014 (in millions):

	December 31, 2015				
	Level 1	Level 2	Level 3	Collateral	Total
Assets:					
Commodity derivative instruments, other current assets	$ —	$ 87	$ —	$ —	$ 87
Liabilities:					
Commodity derivative instruments, accrued liabilities	$ —	$ (1)	$ —	$ —	$ (1)

	December 31, 2014				
	Level 1	Level 2	Level 3	Collateral	Total
Assets:					
Commodity derivative instruments, other current assets	$ —	$ 24	$ —	$ —	$ 24

Fair Values—Nonrecurring

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. 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 acreage. We evaluate 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 current environment.

As a result of impairment testing in the fourth quarter of 2014, we recorded pre-tax charges of $3.4 billion, of which $2.7 billion was for certain proved properties throughout our asset base to reduce these assets to their estimated fair values.

The fair values of the proved properties held and used were determined as of the date of the assessment using discounted cash flow models based on management's expectations for the future. Inputs included estimates of future oil and natural gas production, prices based on recent commodity forward price curves as of the date of the estimate, estimated operating and development costs, and a risk-adjusted discount rate.

Financial Instruments Fair Value

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

NOTE 10 INCOME TAXES

Income / (loss) before income taxes was $(5,476) million, $(2,421) million and $1,447 million for the years ended December 31, 2015, 2014 and 2013, respectively. The provision / (benefit) for federal, state and local income taxes consists of the following:

For the years ended December 31,	United States Federal	State and Local	Total
		(in millions)	
2015			
Current	$ 255	$ 81	$ 336
Deferred	(1,961)	(297)	(2,258)
	$ (1,706)	$ (216)	$ (1,922)
2014			
Current	$ 66	$ 99	$ 165
Deferred	(840)	(312)	(1,152)
	$ (774)	$ (213)	$ (987)
2013			
Current	$ 227	$ 91	$ 318
Deferred	222	38	260
	$ 449	$ 129	$ 578

The following reconciliation of the United States federal statutory income tax rate to our effective tax rate is stated as a percentage of pre-tax income or loss:

	For the years ended December 31,		
	2015	2014	2013
United States federal statutory tax rate	35%	35%	35%
State income taxes, net of federal provision	5	6	6
Valuation allowance	(5)	—	—
Other	—	—	(1)
Effective tax rate	35%	41%	40%

The tax effects of temporary differences resulting in deferred income taxes at December 31, 2015 and 2014 were as follows:

	2015		2014	
	Deferred Tax Assets	Deferred Tax Liabilities	Deferred Tax Assets	Deferred Tax Liabilities
	(in millions)			
Long-term debt	$ 608	$ —	$ —	$ —
Property, plant and equipment differences	132	(427)	—	(2,437)
Postretirement benefit accruals	41	—	39	—
Deferred compensation and benefits	75	—	62	—
Asset retirement obligations	156	—	184	—
Federal effect of state income taxes	28	(24)	68	—
Net operating loss carryforward	7	—	64	—
All other	47	(3)	27	(1)
Subtotal	1,094	(454)	444	(2,438)
Valuation allowance	(382)	—	—	—
Total net deferred taxes	$ 712	$ (454)	$ 444	$ (2,438)

The current portion of deferred tax assets was $59 million and $61 million as of December 31, 2015 and 2014, respectively, which was reported in other current assets. The noncurrent portion of total deferred tax assets was reported in other assets as of December 31, 2015.

We evaluate our deferred tax assets to determine if a valuation allowance is required to reduce our deferred tax assets to an amount expected to be realized. We expect to realize a portion of our deferred tax assets through carryback to a prior income year and reversals of taxable temporary differences. The amount of the deferred tax assets considered realizable could however be adjusted if estimates change. In the fourth quarter of 2015, we recorded a valuation allowance, net of the federal benefit for the state-related portion, of $294 million against our deferred tax assets, which we do not believe are more likely than not to be realized.

As a result of the debt exchange in December 2015, we recognized cancellation of debt income of $1.39 billion in 2015, including $830 million of original issue discount, which represented the excess of the face value of the newly issued notes over their fair value. The original issue discount will be deducted in our tax returns over a seven-year period. The tax gain exceeded our operating loss for the year. We expect to utilize our existing net operating loss (NOL) carryforwards from 2014 as well as our anticipated 2016 NOLs to offset the current tax liability resulting from this gain. As a result, the related $310 million of current federal and state tax provision has been reported in other long-term liabilities in the accompanying balance sheets. We expect this amount to become a deferred tax liability in 2016 as the anticipated losses are incurred.

Prior to the Spin-off date, we were included in the Occidental income tax returns for all applicable years. There could be a settlement between us and Occidental under the tax sharing agreement related to income taxes for the periods prior to the Spin-off. The income tax provision was calculated as if we filed separate tax returns for all periods presented prior to the Spin-off. There were no amounts due to Occidental as of December 31, 2015 and 2014.

We have no liabilities for unrecognized tax benefits as of December 31, 2015 and 2014. We believe there will not be material changes to our unrecognized tax benefits within the next 12 months. We recognize interest and penalties, if any, related to uncertain tax positions in the income tax provision. There were no amounts of interest and penalties related to uncertain tax positions during the years ended December 31, 2015, 2014 and 2013.

As of December 31, 2015, we had approximately $40 million of U.S. federal net operating losses and $106 million of California net operating losses. The net operating loss carryforwards resulted from acquisitions in prior years. The U.S. federal net operating losses begin expiring in 2017 and the California net operating losses begin expiring in 2026. The acquired net operating loss carryforward is subject to an annual limitation as a result of these acquisitions and no financial statement benefit has been recognized for a portion of the net operating loss carryforward.

Our tax returns for the one-month period December 2014 are subject to examination by U.S. federal and California tax authorities. 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.

NOTE 11 STOCK COMPENSATION

General

Prior to the Spin-off, our employees participated in Occidental's stock-based incentive plans under which, if they were eligible, they received Occidental stock awards. Effective on the Spin-off date of November 30, 2014, our employees and non-employee directors began participating in our long-term incentive plan.

Our incentive plan authorizes the Compensation Committee of our Board of Directors to grant up to a total of 25 million shares in the form of stock options, stock appreciation rights, stock awards, performance awards and cash awards, among others, to our employees, non-employee directors and other plan participants. If approved at our 2016 Annual Meeting, the number of shares authorized for grant under our incentive plan will increase to 47 million.

In connection with the Spin-off, unvested share-based compensation awards granted to our employees under Occidental's stock-based incentive plans and held by grantees as of November 30, 2014 were replaced with substitute awards based on CRC common shares. These substitute awards were intended to generally preserve the value of the original Occidental award determined as of November 30, 2014. Original and remaining vesting periods of Occidental awards were unaffected by the substitution. There were approximately 650 employees affected by the substitution of awards.

The substitution of awards did not cause us to recognize incremental compensation expense. These substitute awards reduced the maximum number of shares of our common stock available for delivery under our incentive plan.

During 2015 and 2014, non-employee directors were granted restricted stock units (RSU) awards of approximately 153,750 shares and 74,600 shares of restricted stock, respectively, which fully vest and convert into shares one year from the date of grant. Compensation expense for these awards that will be recognized during the vesting period was measured using the quoted market price of our common stock on the grant date.

Compensation expense for stock-based awards for the year ended December 31, 2015 and the month ended December 31, 2014 was approximately $34 million and $1 million, respectively. Prior to the Spin-off, Occidental allocated certain costs to us which included compensation costs for stock-based awards of Occidental stock. Using the same allocation method for all allocated costs used by Occidental, we estimate the stock compensation expense allocated to us was approximately $26 million, and $33 million for January 1, 2014 through November 30, 2014, and total year 2013, respectively.

For the year ended December 31, 2015, we recognized income tax expense of approximately $2 million and made cash payments of $10 million for the cash-settled portion of our awards vested in 2015. As the stock compensation expenses prior to the Spin-off costs were allocated to us, it was not practical to calculate the tax expense/benefit or cash payments for those years.

As of December 31, 2015, unrecognized compensation expense for all our unvested stock-based incentive awards, based on the year-end value of our common stock, was $53 million. This expense is expected to be recognized over a weighted-average period of 1.94 years.

Restricted Stock Units

Certain employees are awarded RSUs which are in the form of, or equivalent in value to, actual shares of CRC common stock. Depending on their terms, RSUs are settled in cash or stock at the time of vesting. These awards vest ratably over three years, or at the end of two or three years, following the date of grant. For a substantial majority of the RSUs, declared dividend equivalents, if any, are paid during the vesting period.

The following summarizes our RSU activity for the year ended December 31, 2015:

	Cash-Settled		**Stock-Settled**	
	RSUs (000's)	**Weighted-Average Grant Date Fair Value**	**RSUs (000's)**	**Weighted-Average Grant-Date Fair Value**
Unvested at January 1	4,548	$ 7.37	2,773	$ 7.84
Granted	7,497	$ 4.20	—	$ —
Vested	(1,883)	$ 7.23	(1,176)	$ 7.67
Forfeited	(1,122)	$ 5.12	(276)	$ 7.99
Unvested at December 31	**9,040**	**$ 5.05**	**1,321**	**$ 7.94**

Performance Stock Unit Awards

Certain executives are awarded Performance Stock Unit (PSU) awards that vest at the end of a three-year period following the grant date if performance targets are certified as being met. In August 2015, PSU awards were granted that have payouts ranging from 0 to 200 percent of the target award that would settle, once certified, fully in cash. The 2015 PSU awards will convert to stock-settled if approval for additional shares is granted under our long-term incentive plan at the 2016 Annual Meeting. Dividend equivalents, if any, declared during the vesting period are accumulated and paid upon certification, for the number of vested shares.

The performance targets under the 2015 PSU awards are based 50% on achievement of specified VCI results and 50% on TSR relative to a selected peer group of companies over specified multi-year performance periods.

The fair values of the VCI-based portions of the PSU awards are initially determined on the grant date based on an estimated performance achievement at the target level.

A summary of our unvested PSU awards as of December 31, 2015, and changes during the year ended December 31, 2015, is presented below:

	Cash-Settled		Stock-Settled	
	PSUs (000's)	**Weighted-Average Grant Date Fair Value**	**PSUs (000's)**	**Weighted-Average Grant-Date Fair Value**
Unvested at January 1	—	$ —	3,890	$ 7.65
Granted	2,864	$ 4.20	—	$ —
Vested	—	$ —	(670)	$ 7.03
Forfeited	(78)	$ 4.20	—	$ —
Unvested at December 31	**2,786**	**$ 4.20**	**3,220**	**$ 7.78**

The grant date and December 31, 2015 assumptions used in the Monte Carlo valuation for the TSR-based portion of the PSU awards granted during 2015 were as follows:

	December 31, 2015	**Grant Date**
Risk-free interest rate	1.18%	1.06%
Dividend yield	—	0.95%
Volatility factor	50.50%	43.63%
Expected life (years)	2.5	2.9
Fair value of underlying CRC stock	$ 2.33	$ 4.20

Stock Options

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, with one-third vesting and becoming exercisable on each anniversary date following the date of grant.

The following table summarizes our option activity during the year ended December 31, 2015:

	Options (000's)	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Aggregate Intrinsic Value
Beginning balance, January 1	8,481	$ 8.11	$ 1.98	$ —
Granted	3,208	$ 4.20	$ 1.50	$ —
Exercised	—	$ —	$ —	$ —
Forfeited	(174)	$ 8.11	$ 1.98	$ —
Expired or Canceled	—	$ —	$ —	$ —
Ending balance, December 31	**11,515**	**$ 7.02**	**$ 1.85**	**$ —**
Exercisable at December 31	**2,918**	**$ 7.98**	**$ 1.96**	**$ —**

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	$ 4.20	$ 8.11
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	$ 1.50	$ 1.98

Employee Stock Purchase Plan

Effective January 1, 2015, we adopted the California Resources Corporation 2014 Employee Stock Purchase Plan (ESPP). 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 which may be issued pursuant to the ESPP is subject to certain annual limits and has a cumulative limit of 5 million shares, subject to adjustment pursuant to the terms of the ESPP. If approved at our 2016 Annual Meeting, the number of shares authorized for issuance under our ESPP will increase to 10 million. For the year ended December 31, 2015, we issued approximately 2.1 million shares of common stock in connection with the ESPP. As of January 1, 2016, over 50% of our employees had elected to participate in the plan.

NOTE 12 EQUITY

The following is a summary of common stock issuances:

	Common Stock (in 000's)
Balance, December 31, 2013	—
Issued	385,640
Balance, December 31, 2014	385,640
Issued	2,540
Balance, December 31, 2015	388,180

Preferred Stock

In November 2014, our board of directors authorized 200 million shares of preferred stock with a par value of $0.01 per share. At December 31, 2015 and 2014, we had no outstanding shares of preferred stock.

ACCUMULATED OTHER COMPREHENSIVE INCOME / (LOSS)

Accumulated other comprehensive loss consisted of pension and post-retirement losses of $15 million and $24 million, at December 31, 2015 and 2014, respectively.

NOTE 13 EARNINGS PER SHARE

On December 1, 2014, the Spin-off date, 381.4 million shares of our common stock were distributed, of which approximately 18.5% was retained by Occidental and will be divested on March 24, 2016. For comparative purposes, and to provide a more meaningful calculation of weighted-average shares outstanding, we have assumed this amount to be outstanding as of the beginning of each period prior to the Spin-off. In addition, we have assumed the vested stock awards granted in December 2014 were also outstanding for each of the periods presented prior to the Spin-off, resulting in a weighted-average basic share count of 381.8 million shares for those periods. The effect of stock options granted in August 2015 and December 2014 was anti-dilutive for the periods presented. For the year ended December 31, 2015, we issued approximately 2.1 million shares of common stock in connection with our employee stock purchase plan. The effect of the stock purchase plan was anti-dilutive for the year ended December 31, 2015.

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

	2015	2014	2013
	(in millions, except per-share amounts)		
Basic EPS calculation			
Net income / (loss)	$ (3,554)	$ (1,434)	$ 869
Net income / (loss) allocated to participating securities	—	—	(14)
Net income / (loss) available to common stockholders	$ (3,554)	$ (1,434)	$ 855
Weighted-average common shares outstanding—basic	383.2	381.9	381.8
Basic EPS	$ (9.27)	$ (3.75)	$ 2.24
Diluted EPS calculation			
Net income / (loss)	$ (3,554)	$ (1,434)	$ 869
Net income / (loss) allocated to participating securities	—	—	(14)
Net income / (loss) available to common stockholders	$ (3,554)	$ (1,434)	$ 855
Weighted-average common shares outstanding—basic	383.2	381.9	381.8
Dilutive effect of potentially dilutive securities	—	—	—
Weighted-average common shares outstanding—diluted	383.2	381.9	381.8
Diluted EPS	$ (9.27)	$ (3.75)	$ 2.24

NOTE 14 RETIREMENT AND POSTRETIREMENT BENEFIT PLANS

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

Defined Contribution Plans

All of our employees were eligible to participate in one or more of the defined contribution retirement or savings plans that provide for periodic contributions by us, our subsidiaries or, prior to the Spin-off, by Occidental, based on plan-specific criteria, such as base pay, age, level and employee contributions. Certain salaried employees participated in supplemental plans that restored benefits lost due to governmental limitations on qualified plan benefits. The accrued liabilities for the supplemental plans were $32 million and $27 million as of December 31, 2015 and 2014, respectively, and we expensed $39 million in 2015, $29 million in 2014 and $34 million in 2013 under the provisions of these defined contribution plans. In February 2016, we substantially reduced our contributions to these defined contribution plans.

Defined Benefit Plans

Participation in defined benefit pension plans sponsored by us is limited. During 2015, approximately 260 employees, including union and certain nonunion employees who joined us from acquired operations with grandfathered benefits, accrued benefits under these plans. 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 generally funded by payments to trust funds, which are administered by independent trustees.

Postretirement and Other Benefit Plans

We provided postretirement medical and dental benefits and life insurance coverage for our former employees and their eligible dependents through Occidental-sponsored plans prior to the Spin-off, and provide them through CRC-sponsored plans following the Spin-off. The benefits were generally funded as they were paid during the year.

Obligations and Funded Status

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 (in millions):

	Pension Benefits		Postretirement Benefits	
	As of December 31,			
	2015	2014	2015	2014
Amounts recognized in the balance sheet:				
Accrued liabilities	$ —	$ —	$ (1)	$ —
Other long-term liabilities	(27)	(21)	(70)	(68)
	$ (27)	$ (21)	$ (71)	$ (68)
AOCI included the following after-tax balances:				
Net loss (gain)	$ 19	$ 22	$ (4)	$ 2

	Pension Benefits		Postretirement Benefits	
	2015	2014	2015	2014
Changes in the benefit obligation:				
Benefit obligation—beginning of year	$ 108	$ 103	$ 68	$ 63
Service cost—benefits earned during the period	4	4	5	4
Interest cost on projected benefit obligation	4	4	3	2
Curtailment (gain) loss	(12)	—	5	—
Actuarial loss (gain)	24	6	(10)	(1)
Benefits paid	(45)	(9)	—	—
Benefit obligation—end of year	$ 83	$ 108	$ 71	$ 68
Changes in plan assets:				
Fair value of plan assets—beginning of year	$ 87	$ 91	$ —	$ —
Actual return on plan assets	1	5	—	—
Employer contributions	13	—	—	—
Benefits paid	(45)	(9)	—	—
Fair value of plan assets—end of year	$ 56	$ 87	$ —	$ —
Unfunded status:	$ (27)	$ (21)	$ (71)	$ (68)

The following table sets forth the accumulated and projected benefit obligations and fair values of assets of the defined benefit pension plans:

	Accumulated Benefit Obligation in Excess of Plan Assets		Plan Assets in Excess of Accumulated Benefit Obligation	
	As of December 31,			
	2015	2014	2015	2014
	(in millions)			
Projected Benefit Obligation	$ 83	$ 31	$ —	$ 77
Accumulated Benefit Obligation	$ 81	$ 26	$ —	$ 62
Fair Value of Plan Assets	$ 56	$ 19	$ —	$ 68

We do not expect any plan assets to be returned during 2016.

COMPONENTS OF NET PERIODIC BENEFIT COST

The following table sets forth the components of net periodic benefit costs:

	Pension Benefits			Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
	(in millions)					
Net periodic benefit costs:						
Service cost—benefits earned during the period	$ 4	$ 4	$ 5	$ 5	$ 4	$ 5
Interest cost on projected benefit obligation	4	4	3	3	2	3
Expected return on plan assets	(5)	(6)	(4)	—	—	—
Recognized actuarial loss	3	2	4	—	1	2
Settlement cost	18	2	2	—	—	—
Curtailment loss	—	—	—	5	—	—
Net periodic benefit cost	$ 24	$ 6	$ 10	$ 13	$ 7	$ 10

The estimated net 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 $3 million and $1 million, respectively. We do not expect to have any estimated net 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:

	Pension Benefits		Postretirement Benefits	
	For the years ended December 31,			
	2015	2014	2015	2014
Benefit Obligation Assumptions:				
Discount rate	3.99%	3.82%	4.81%	4.44%
Rate of compensation increase	4.00%	4.00%	—	—
Net Periodic Benefit Cost Assumptions:				
Discount rate	3.82%	4.45%	4.44%	4.75%
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 2015 and 2014. 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 2015, we adopted the Society of Actuaries MP-2015 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 2014, we utilized the Society of Actuaries Adjusted RP-2014 Mortality Table reflecting the MP-2014 Mortality Improvement Scale. The changes in the mortality assumptions resulted in a decrease of less than $1 million and $1 million in the pension and postretirement benefit obligations, respectively, at December 31, 2015.

The postretirement benefit obligation was determined by application of the terms of medical and dental benefits and life insurance coverage, 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 1.60% and 1.79% as of December 31, 2015 and 2014, respectively. 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 healthcare cost trend rates would decrease 0.25 percent per year from 7.5% in 2015 until they reach 5.0% in 2025, and remain at 5.0% thereafter. A 1-percent increase or a 1-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, 2015. 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. The investments were monitored by Occidental's Investment Committee in its role as fiduciary through November 30, 2014, and by our Investment Committee thereafter. Equity investments were diversified across United States and non-United States 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. 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 (in millions):

	Fair Value Measurements at December 31, 2015 Using			
	Level 1	**Level 2**	**Level 3**	**Total**
Asset Class:				
Commingled funds:				
Fixed income	$ —	$ 15	$ —	$ 15
U.S. equity	—	16	—	16
International equity	—	10	—	10
Mutual funds:				
Bond funds	4	—	—	4
Blend funds	2	—	—	2
Value funds	1	—	—	1
Growth funds	2	—	—	2
Guaranteed deposit account	—	—	6	6
Total pension plan assets	$ 9	$ 41	$ 6	$ 56

	Fair Value Measurements at December 31, 2014 Using			
	Level 1	**Level 2**	**Level 3**	**Total**
Asset Class:				
Commingled funds:				
Fixed income	$ —	$ 20	$ —	$ 20
U.S. equity	—	31	—	31
International equity	—	17	—	17
Mutual funds:				
Bond funds	5	—	—	5
Blend funds	2	—	—	2
Value funds	2	—	—	2
Growth funds	3	—	—	3
Guaranteed deposit account	—	—	7	7
Total pension plan assets	$ 12	$ 68	$ 7	$ 87

The activity during the years ended December 31, 2015 and 2014, for the assets using Level 3 fair value measurements was insignificant. We expect to contribute $8 million to our defined benefit pension plans during 2016.

Estimated future benefit payments, which reflect expected future service, as appropriate, are as follows:

For the years ended December 31,	Pension Benefits	Postretirement Benefits
	(in millions)	
2016	$ 22	$ 1
2017	$ 8	$ 3
2018	$ 9	$ 3
2019	$ 6	$ 3
2020	$ 6	$ 4
2021 - 2025	$ 25	$ 22

NOTE 15 RELATED-PARTY TRANSACTIONS

During 2014 and 2013, we entered into the following related-party transactions:

	2014	2013
	(in millions)	
Sales[(a)]	$ 2,706	$ 4,174
Allocated costs for services provided by affiliates	$ 126	$ 146
Purchases	$ 175	$ 164

(a) Amounts include related-party sales from our Elk Hills power plant of $89 million and $120 million during 2014 and 2013, respectively. These sales are included in other revenue in the statements of operations.

Through July 2014, substantially all of our products were sold through Occidental's marketing subsidiaries at market prices and were settled at the time of sale to those entities. Beginning August 2014, we started marketing our own products directly to third parties. For the years ended December 31, 2014 and 2013, sales to Occidental subsidiaries accounted for approximately 65% and 97% of our net sales, respectively.

The statements of operations for the years ended December 31, 2014 and 2013, include expense allocations for certain corporate functions and centrally-located activities performed by Occidental prior to the Spin-off. These functions include executive oversight, accounting, treasury, tax, financial reporting, internal audit, legal, risk management, information technology, government relations, public relations, investor relations, human resources, procurement, engineering, drilling, exploration, finance, marketing, ethics and compliance, and certain other shared services. Charges from Occidental for these services were generally reflected in general and administrative expenses and also include employee-related costs such as salaries, bonuses and stock compensation costs.

Purchases from related parties reflected products purchased at market prices from Occidental's subsidiaries and used in our operations. These purchases are included in production costs. There were no related-party receivable or payable balances at December 31, 2015 and 2014.

Quarterly Financial Data (Unaudited)

Quarter	2015 First	2015 Second	2015 Third	2015 Fourth	2014 First	2014 Second	2014 Third	2014 Fourth
	(in millions, except per share amounts)							
Revenues	$ 577	$ 634	$ 626	$ 566	$ 1,121	$ 1,140	$ 1,092	$ 820
Gross profit	$ 335	$ 392	$ 380	$ 345	$ 857	$ 870	$ 821	$ 568
Net income / (loss)[(a)]	$ (100)	$ (68)	$ (104)	$ (3,282)	$ 223	$ 246	$ 188	$ (2,091)
Net income / (loss) per share[(b)]:								
Basic	$ (0.26)	$ (0.18)	$ (0.27)	$ (8.54)	$ 0.57	$ 0.63	$ 0.48	$ (5.47)
Diluted	$ (0.26)	$ (0.18)	$ (0.27)	$ (8.54)	$ 0.57	$ 0.63	$ 0.48	$ (5.47)

(a) For the second quarter of 2015, amount included non-cash after-tax charges consisting of $10 million in hedge-related losses and $6 million in early retirement and severance costs. For the third quarter of 2015, amount included non-cash after-tax gains of $36 million for hedges, offset by $42 million in early retirement and severance costs. For the fourth quarter of 2015, amount included unusual and infrequent after-tax charges consisting of $2.9 billion of asset impairments for proved and unproved properties, $42 million in write-down of certain other assets, $5 million in debt transaction costs and $3 million in rig termination and other costs, partially offset by $14 million in non-cash hedge-related gains and other. The fourth quarter of 2015 also included a $294 million deferred tax valuation allowance. For the fourth quarter of 2014, amount included unusual and infrequent after-tax charges consisting of $2.0 billion of asset impairments, $31 million of rig termination and other price-related costs, and $33 million of Spin-off and transition related costs.

(b) For comparative purposes, and to provide a more meaningful calculation for weighted-average shares, we assumed the shares distributed to Occidental stockholders in conjunction with the Spin-off were outstanding at the beginning of each period prior to the Spin-off.

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

The following tables set forth our net 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. Reserves are stated net of applicable royalties. 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.

OIL RESERVES

	San Joaquin Basin	Los Angeles Basin[(a)]	Ventura Basin	Sacramento Basin	Total
		(in millions of barrels (MMBbl))			
PROVED DEVELOPED AND UNDEVELOPED RESERVES					
Balance at December 31, 2012	312	138	47	—	497
Revisions of previous estimates	(8)	3	(3)	—	(8)
Improved recovery	49	24	3	—	76
Extensions and discoveries	—	—	—	—	—
Acquisitions	—	—	—	—	—
Sales of proved reserves	—	—	—	—	—
Production	(21)	(10)	(2)	—	(33)
Balance at December 31, 2013	332	155	45	—	532
Revisions of previous estimates	(41)	8	(4)	—	(37)
Improved recovery	70	11	4	—	85
Extensions and discoveries	1	—	—	—	1
Acquisitions	1	—	5	—	6
Sales of proved reserves	—	—	—	—	—
Production	(23)	(11)	(2)	—	(36)
Balance at December 31, 2014	340	163	48	—	551
Revisions of previous estimates	(35)	(33)	(12)	—	(80)
Improved recovery	3	—	—	—	3
Extensions and discoveries	8	12	5	—	25
Acquisitions	4	—	—	—	4
Sales of proved reserves	—	—	—	—	—
Production	(23)	(12)	(2)	—	(37)
Balance at December 31, 2015	297	130	39	—	466
PROVED DEVELOPED RESERVES					
December 31, 2012	221	104	30	—	355
December 31, 2013	226	109	28	—	363
December 31, 2014	229	124	34	—	387
December 31, 2015[(b)]	205	103	30	—	338
PROVED UNDEVELOPED RESERVES					
December 31, 2012	91	34	17	—	142
December 31, 2013	106	46	17	—	169
December 31, 2014	111	39	14	—	164
December 31, 2015	92	27	9	—	128

(a) Includes proved reserves related to economic arrangements similar to PSCs of 103 MMBbl, 116 MMBbl, 102 MMBbl and 98 MMBbl at December 31, 2015, 2014, 2013 and 2012, respectively.

(b) Approximately 16% of the proved developed reserves at December 31, 2015 are nonproducing.

NGL RESERVES

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in MMBbl)		
PROVED DEVELOPED AND UNDEVELOPED RESERVES					
Balance at December 31, 2012	58	—	3	—	61
Revisions of previous estimates	13	—	—	—	13
Improved recovery	4	—	—	—	4
Extensions and discoveries	—	—	—	—	—
Acquisitions	—	—	—	—	—
Sales of proved reserves	—	—	—	—	—
Production	(7)	—	—	—	(7)
Balance at December 31, 2013	68	—	3	—	71
Revisions of previous estimates	8	—	—	—	8
Improved recovery	13	—	—	—	13
Extensions and discoveries	—	—	—	—	—
Acquisitions	—	—	—	—	—
Sales of proved reserves	—	—	—	—	—
Production	(7)	—	—	—	(7)
Balance at December 31, 2014	82	—	3	—	85
Revisions of previous estimates	(23)	—	—	—	(23)
Improved recovery	—	—	—	—	—
Extensions and discoveries	2	—	—	—	2
Acquisitions	1	—	—	—	1
Sales of proved reserves	—	—	—	—	—
Production	(6)	—	—	—	(6)
Balance at December 31, 2015	56	—	3	—	59
PROVED DEVELOPED RESERVES					
December 31, 2012	42	—	1	—	43
December 31, 2013	47	—	1	—	48
December 31, 2014	62	—	2	—	64
December 31, 2015[(a)]	45	—	2	—	47
PROVED UNDEVELOPED RESERVES					
December 31, 2012	16	—	2	—	18
December 31, 2013	21	—	2	—	23
December 31, 2014	20	—	1	—	21
December 31, 2015	11	—	1	—	12

(a) Approximately 9% of the proved developed reserves at December 31, 2015 are nonproducing.

NATURAL GAS RESERVES

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
	(in billions of cubic feet (Bcf))				
PROVED DEVELOPED AND UNDEVELOPED RESERVES					
Balance at December 31, 2012	694	18	36	186	934
Revisions of previous estimates	(4)	(4)	(1)	(38)	(47)
Improved recovery	47	3	2	—	52
Extensions and discoveries	—	—	—	—	—
Acquisitions	—	—	—	—	—
Sales of proved reserves	—	—	—	—	—
Production	(66)	(1)	(4)	(24)	(95)
Balance at December 31, 2013	671	16	33	124	844
Revisions of previous estimates	(91)	—	4	7	(80)
Improved recovery	107	—	2	5	114
Extensions and discoveries	—	—	—	—	—
Acquisitions	—	—	2	—	2
Sales of proved reserves	—	—	—	—	—
Production	(66)	—	(4)	(20)	(90)
Balance at December 31, 2014	621	16	37	116	790
Revisions of previous estimates	(2)	(5)	(6)	(20)	(33)
Improved recovery	—	—	—	—	—
Extensions and discoveries	27	1	—	6	34
Acquisitions	8	—	—	—	8
Sales of proved reserves	—	—	—	—	—
Production	(63)	(1)	(4)	(16)	(84)
Balance at December 31, 2015	591	11	27	86	715
PROVED DEVELOPED RESERVES					
December 31, 2012	475	13	26	154	668
December 31, 2013	455	9	22	117	603
December 31, 2014	458	11	28	110	607
December 31, 2015[(a)]	456	9	24	86	575
PROVED UNDEVELOPED RESERVES					
December 31, 2012	219	5	10	32	266
December 31, 2013	216	7	11	7	241
December 31, 2014	163	5	9	6	183
December 31, 2015	135	2	3	—	140

(a) Approximately 14% of the proved developed reserves at December 31, 2015 are nonproducing.

TOTAL RESERVES

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in MMBoe[a])		
PROVED DEVELOPED AND UNDEVELOPED RESERVES					
Balance at December 31, 2012	486	141	58	29	714
Revisions of previous estimates	4	2	(3)	(6)	(3)
Improved recovery	61	25	3	—	89
Extensions and discoveries	—	—	—	—	—
Acquisitions	—	—	—	—	—
Sales of proved reserves	—	—	—	—	—
Production	(40)	(10)	(3)	(3)	(56)
Balance at December 31, 2013	511	158	55	20	744
Revisions of previous estimates	(48)	8	(3)	1	(42)
Improved recovery	101	11	4	1	117
Extensions and discoveries	1	—	—	—	1
Acquisitions	1	—	5	—	6
Sales of proved reserves	—	—	—	—	—
Production	(41)	(11)	(3)	(3)	(58)
Balance at December 31, 2014	525	166	58	19	768
Revisions of previous estimates	(58)	(34)	(13)	(3)	(108)
Improved recovery	3	—	—	—	3
Extensions and discoveries	15	12	5	1	33
Acquisitions	6	—	—	—	6
Sales of proved reserves	—	—	—	—	—
Production	(40)	(12)	(3)	(3)	(58)
Balance at December 31, 2015	451	132	47	14	644
PROVED DEVELOPED RESERVES					
December 31, 2012	341	105	38	24	508
December 31, 2013	349	110	35	20	514
December 31, 2014	367	126	41	18	552
December 31, 2015[c]	326	105	36	14	481
PROVED UNDEVELOPED RESERVES					
December 31, 2012	145	36	20	5	206
December 31, 2013	162	48	20	—	230
December 31, 2014	158	40	17	1	216
December 31, 2015	125	27	11	—	163

(a) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas and one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2015, the average prices of Brent oil and NYMEX natural gas were $53.64 per Bbl and $2.75 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 20 to 1.

(b) Includes proved reserves related to economic arrangements similar to PSCs of 103 MMBbl, 116 MMBbl, 102 MMBbl and 98 MMBbl at December 31, 2015, 2014, 2013 and 2012 respectively.

(c) Approximately 15% of the proved developed reserves at December 31, 2015 are nonproducing.

CAPITALIZED COSTS

Capitalized costs relating to oil and gas producing activities and related accumulated depreciation, depletion and amortization were as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in millions)		
December 31, 2015					
Proved properties	$ 15,549	$ 2,071	$ 1,352	$ 374	$ 19,346
Unproved properties	544	106	172	289	1,111
Total capitalized costs[a]	16,093	2,177	1,524	663	20,457
Accumulated depreciation, depletion and amortization[b]	(11,166)	(1,491)	(1,208)	(603)	(14,468)
Net capitalized costs	$ 4,927	$ 686	$ 316	$ 60	$ 5,989
December 31, 2014					
Proved properties	$ 15,362	$ 1,982	$ 1,353	$ 326	$ 19,023
Unproved properties	469	106	113	323	1,011
Total capitalized costs[a]	15,831	2,088	1,466	649	20,034
Accumulated depreciation, depletion and amortization[b]	(6,846)	(826)	(495)	(497)	(8,664)
Net capitalized costs	$ 8,985	$ 1,262	$ 971	$ 152	$ 11,370
December 31, 2013					
Proved properties	$ 15,120	$ 2,487	$ 1,479	$ 542	$ 19,628
Unproved properties	589	105	95	110	899
Total capitalized costs[a]	15,709	2,592	1,574	652	20,527
Accumulated depreciation, depletion and amortization[b]	(5,764)	(571)	(346)	(146)	(6,827)
Net capitalized costs	$ 9,945	$ 2,021	$ 1,228	$ 506	$ 13,700

(a) Includes acquisition costs, development costs and asset retirement obligations.

(b) Includes accumulated valuation allowance for total unproved properties of $819 million, $715 million and $27 million at December 31, 2015, 2014 and 2013, respectively.

COSTS INCURRED

Costs incurred relating to oil and gas activities that included capital investments, exploration (whether expensed or capitalized), acquisitions and asset retirement obligations and excluded corporate items were as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in millions)		
FOR THE YEAR ENDED DECEMBER 31, 2015					
Property acquisition costs					
Proved properties	$ 73	$ 2	$ 2	$ —	$ 77
Unproved properties	65	—	—	—	65
Exploration costs	36	—	4	3	43
Development costs[(a)]	191	89	10	—	290
Costs incurred	$ 365	$ 91	$ 16	$ 3	$ 475
FOR THE YEAR ENDED DECEMBER 31, 2014					
Property acquisition costs					
Proved properties	$ 79	$ 3	$ 128	$ —	$ 210
Unproved properties	21	—	81	—	102
Exploration costs	105	—	14	5	124
Development costs	1,356	495	99	12	1,962
Costs incurred	$ 1,561	$ 498	$ 322	$ 17	$ 2,398
FOR THE YEAR ENDED DECEMBER 31, 2013					
Property acquisition costs					
Proved properties	$ 14	$ 1	$ —	$ 5	$ 20
Unproved properties	23	9	1	—	33
Exploration costs	127	—	1	3	131
Development costs	1,078	371	110	15	1,574
Costs incurred	$ 1,242	$ 381	$ 112	$ 23	$ 1,758

(a) Total development costs includes a $62 million reduction in asset retirement obligations.

RESULTS OF OPERATIONS

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

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in millions)		
FOR THE YEAR ENDED DECEMBER 31, 2015					
Revenues[a]	$ 1,518	$ 582	$ 126	$ 47	$ 2,273
Production costs[b]	564	278	85	24	951
General and administrative expenses[c]	28	21	7	2	58
Other operating expenses[d]	15	2	2	2	21
Depreciation, depletion and amortization	808	100	48	20	976
Taxes other than on income	97	45	13	1	156
Asset impairments[e]	3,554	571	613	114	4,852
Exploration expenses	30	—	3	3	36
Pretax income / (loss)	(3,578)	(435)	(645)	(119)	(4,777)
Income tax benefit	(1,458)	(177)	(263)	(48)	(1,946)
Results of operations	$ (2,120)	$ (258)	$ (382)	$ (71)	$ (2,831)
FOR THE YEAR ENDED DECEMBER 31, 2014					
Revenues[a]	$ 2,735	$ 956	$ 244	$ 88	$ 4,023
Production costs[b]	596	342	92	27	1,057
General and administrative expenses[c]	37	31	9	8	85
Other operating expenses[d]	21	2	3	4	30
Depreciation, depletion and amortization	875	148	79	81	1,183
Taxes other than on income	140	49	8	6	203
Asset impairments[e]	1,266	1,110	437	589	3,402
Exploration expenses[f]	104	—	9	5	118
Pretax income / (loss)	(304)	(726)	(393)	(632)	(2,055)
Income tax benefit	(124)	(296)	(161)	(258)	(839)
Results of operations	$ (180)	$ (430)	$ (232)	$ (374)	$ (1,216)
FOR THE YEAR ENDED DECEMBER 31, 2013					
Revenues[a]	$ 2,823	$ 968	$ 259	$ 89	$ 4,139
Production costs[b]	565	315	78	28	986
General and administrative expenses	37	28	7	10	82
Other operating expenses	21	8	3	2	34
Depreciation, depletion and amortization	851	108	73	97	1,129
Taxes other than on income	109	43	9	10	171
Exploration expenses	94	1	13	8	116
Pretax income / (loss)	1,146	465	76	(66)	1,621
Income tax expense / (benefit)	456	185	30	(26)	645
Results of operations	$ 690	$ 280	$ 46	$ (40)	$ 976

(a) Revenues are net of royalty payments.

(b) 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, but do not include DD&A, royalties, income taxes and general and administrative expenses.

(c) For 2015, the amounts exclude unusual and infrequent costs related to early retirement and severance costs associated with personnel totaling $18 million. For 2014, the amounts exclude unusual and infrequent costs related to Spin-off and transition related costs totaling $6 million.

(d) For 2015, the amounts exclude unusual and infrequent costs related to write down of certain assets and rig termination charges totaling $82 million. For 2014, the amounts exclude unusual and infrequent costs related to rig termination charges and Spin-off and transition related costs totaling $55 million.

(e) At year end 2015 and 2014, we recorded pre-tax asset impairment charges of $4.9 billion and $3.4 billion, respectively, on certain proved and unproved properties in the San Joaquin, Los Angeles, Ventura and Sacramento basins.

(f) Excludes $21 million of unusual and infrequent costs related to dry holes and seismic charges.

RESULTS PER UNIT OF PRODUCTION

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in millions)		
FOR THE YEAR ENDED DECEMBER 31, 2015					
Revenue from each barrel of oil equivalent ($/Boe)[a][b]	$ 37.88	$ 47.76	$ 36.98	$ 17.44	$ 38.95
Production costs	14.08	22.81	24.95	8.91	16.30
General and administrative expenses[c]	0.70	1.72	2.05	0.74	1.00
Other operating expenses[d]	0.37	0.16	0.59	0.74	0.36
Depreciation, depletion and amortization	20.16	8.21	14.09	7.42	16.72
Taxes other than on income	2.42	3.69	3.82	0.37	2.67
Asset impairments[e]	88.69	46.85	179.92	42.30	83.14
Exploration expenses	0.75	—	0.88	1.11	0.62
Pretax income / (loss)	(89.29)	(35.68)	(189.32)	(44.15)	(81.86)
Income tax benefit	(36.39)	(14.52)	(77.19)	(17.81)	(33.35)
Results of operations	$ (52.90)	$ (21.16)	$ (112.13)	$ (26.34)	$ (48.51)
FOR THE YEAR ENDED DECEMBER 31, 2014					
Revenue from each barrel of oil equivalent ($/Boe)[a][b]	$ 67.32	$ 88.96	$ 75.73	$ 26.11	$ 69.40
Production costs	14.66	31.82	28.68	7.92	18.23
General and administrative expenses[c]	0.91	2.88	2.79	2.37	1.47
Other operating expenses[d]	0.52	0.19	0.93	1.19	0.55
Depreciation, depletion and amortization	21.52	13.77	24.52	24.04	20.40
Taxes other than on income	3.44	4.56	2.48	1.78	3.50
Asset impairments[e]	31.14	103.29	135.63	174.78	58.66
Exploration expenses	2.56	—	2.79	1.48	2.03
Pretax income / (loss)	(7.43)	(67.55)	(122.09)	(187.45)	(35.44)
Income tax benefit	(3.05)	(27.55)	(49.97)	(76.85)	(14.47)
Results of operations	$ (4.38)	$ (40.00)	$ (72.12)	$ (110.60)	$ (20.97)
FOR THE YEAR ENDED DECEMBER 31, 2013					
Revenue from each barrel of oil equivalent ($/Boe)[a][b]	$ 71.86	$ 101.17	$ 79.28	$ 22.09	$ 73.72
Production costs	14.38	32.93	23.75	7.02	17.56
General and administrative expenses	0.94	2.93	2.14	2.48	1.46
Other operating expenses	0.53	0.83	0.92	0.50	0.60
Depreciation, depletion and amortization	21.66	11.29	22.34	24.08	20.11
Taxes other than on income	2.77	4.49	2.75	2.48	3.05
Exploration expenses	2.39	0.10	3.98	1.99	2.07
Pretax income / (loss)	29.19	48.60	23.40	(16.46)	28.87
Income tax expense / (benefit)	11.61	19.34	9.18	(6.45)	11.49
Results of operations	$ 17.58	$ 29.26	$ 14.22	$ (10.01)	$ 17.38

(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 price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2015, the average prices of Brent oil and NYMEX natural gas were $53.64 per Bbl and $2.75 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 20 to 1.

(b) Revenues are net of royalty payments.

(c) For 2015, the amounts exclude unusual and infrequent costs related to early retirement and severance costs associated with field personnel totaling $0.31 per Boe. For 2014, the amounts exclude unusual and infrequent costs related to Spin-off and transition related costs totaling $0.10 per Boe.

(d) For 2015, the amounts exclude unusual and infrequent costs related to the write-down of certain assets and rig termination charges of totaling $1.42 per Boe. For 2014, the amounts exclude unusual and infrequent costs related to rig termination charges and Spin-off and transition related costs totaling $0.97 per Boe.

(e) At year end 2015 and 2014, we recorded pre-tax asset impairment charges of $4.9 billion and $3.4 billion, respectively, on certain proved and unproved properties in the San Joaquin, Los Angeles, Ventura and Sacramento basins.

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

For purposes of the following disclosures, future 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, 2015, 2014 and 2013, respectively. The realized prices used to calculate future cash flows vary by producing area and market conditions. Future operating and capital costs were forecast using the current cost environment applied to expectations of future operating and development activities. Future income tax expenses were computed by applying, generally, year-end statutory tax rates (adjusted for permanent differences, tax credits and allowances) to the estimated net future pre-tax cash flows, after allowing for the tax basis of the assets. The discount was computed by application of a 10-percent discount factor. The calculations assumed the continuation of existing economic, operating and contractual conditions at December 31, 2015, 2014 and 2013. 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

	Total
	(in millions)
AT DECEMBER 31, 2015	
Future cash inflows	$ 26,477
Future costs	
Production costs[(a)]	(13,458)
Development costs[(b)]	(3,502)
Future income tax expense	(1,858)
Future net cash flows	7,659
Ten percent discount factor	(3,635)
Standardized measure of discounted future net cash flows	$ 4,024
AT DECEMBER 31, 2014	
Future cash inflows	$ 59,709
Future costs	
Production costs[(a)]	(22,906)
Development costs[(b)]	(4,858)
Future income tax expense	(10,322)
Future net cash flows	21,623
Ten percent discount factor	(10,795)
Standardized measure of discounted future net cash flows	$ 10,828
AT DECEMBER 31, 2013	
Future cash inflows	$ 60,884
Future costs	
Production costs[(a)]	(29,523)
Development costs[(b)]	(6,327)
Future income tax expense	(8,213)
Future net cash flows	16,821
Ten percent discount factor	(7,598)
Standardized measure of discounted future net cash flows	$ 9,223

(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,		
	2015	2014	2013
		(in millions)	
Beginning of year	$ 10,828	$ 9,223	$ 9,073
Sales and transfers of oil and natural gas produced, net of production costs and other operating expenses	(1,038)	(2,658)	(3,082)
Net change in prices received per Bbl, production costs and other operating expenses	(12,362)	567	575
Extensions, discoveries and improved recovery, net of future production and development costs	292	2,593	1,914
Change in estimated future development costs	792	75	(688)
Revisions of quantity estimates	(872)	(925)	(62)
Previously estimated development costs incurred during the period	394	1,440	1,185
Accretion of discount	1,474	1,324	1,292
Net change in income taxes	4,228	(468)	(95)
Purchases and sales of reserves in place, net	45	125	4
Changes in production rates and other	243	(468)	(893)
Net change	(6,804)	1,605	150
End of year	$ 4,024	$ 10,828	$ 9,223

OIL, NGL and NATURAL GAS PRODUCTION PER DAY

The following table set forth the production volumes of oil, NGLs and natural gas per day for each of the three years in the period ended December 31, 2015:

	2015	2014	2013
Oil (MBbl/d)			
San Joaquin Basin[b]	64	64	58
Los Angeles Basin[c]	34	29	26
Ventura Basin	6	6	6
Sacramento Basin	—	—	—
Total	104	99	90
NGLs (MBbl/d)			
San Joaquin Basin[b]	17	18	19
Los Angeles Basin	—	—	—
Ventura Basin	1	1	1
Sacramento Basin	—	—	—
Total	18	19	20
Natural gas (MMcf/d)			
San Joaquin Basin[b]	172	180	182
Los Angeles Basin[c]	2	1	2
Ventura Basin	11	11	11
Sacramento Basin	44	54	65
Total	229	246	260
Total Production (MBoe/d)[a]	160	159	154

(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 price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2015, the average prices of Brent oil and NYMEX natural gas were $53.64 per Bbl and $2.75 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 20 to 1.

(b) Includes daily production from Elk Hills field of 24 MBbl oil, 15 MBbl NGLs and 123 MMcf natural gas in 2015; 25 MBbl oil, 16 MBbl NGLs and 136 MMcf natural gas in 2014; and 26 MBbl oil, 18 MBbl NGLs and 145 MMcf natural gas in 2013.

(c) Includes daily production from Wilmington field of 28 MBbl Oil and 1 MMcf natural gas in 2015; 25 MBbl Oil in 2014; and 22 MBbl Oil in 2013.

Schedule II—Valuation and Qualifying Accounts
(in millions)

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions[(a)]	Balance at End of Period
2015					
Deferred tax valuation allowance[(b)]	$ —	$ 294	$ 88	$ —	$ 382
Other asset valuation allowance	$ 10	$ 58	$ —	$ —	$ 68
Environmental reserves	$ 8	$ —	$ —	$ (1)	$ 7
2014					
Other asset valuation allowance	$ —	$ 10	$ —	$ —	$ 10
Environmental reserves	$ 8	$ 1	$ —	$ (1)	$ 8
2013					
Environmental reserves	$ 11	$ 1	$ —	$ (4)	$ 8

(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

The management of California Resources Corporation and its subsidiaries (CRC) is responsible for establishing and maintaining adequate internal control over financial reporting. CRC's 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. CRC's 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 CRC's 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 CRC's receipts and expenditures are being made only in accordance with authorizations of CRC's management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of CRC'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.

Management has assessed the effectiveness of CRC's internal control system as of December 31, 2015, 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, management believes that, as of December 31, 2015, CRC's system of internal control over financial reporting is effective.

CRC's independent auditors, KPMG LLP, have issued an audit report on CRC's internal control over financial reporting, which is set forth in Item 8.

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, 2015, 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

On February 26, 2016, we were notified by New York Stock Exchange (NYSE) that we do not presently satisfy the NYSE's continued listing criteria under Section 802.01C of the NYSE Listed Company Manual because the average closing price of our common stock was less than $1.00 over a consecutive 30 trading-day period as of February 24, 2016.

We plan to notify the NYSE of our intent to cure the deficiency and return to compliance with the NYSE continued listing requirements. We can regain compliance if, during the six-month period following receipt of the NYSE notice, on the last trading-day of any calendar month, our common stock has a closing share price of at least $1.00 and an average closing share price of at least $1.00 over the 30 trading-day period ending on the last trading day of that month. We plan to seek stockholder approval for a reverse stock split at our May 2016 annual meeting in order to regain compliance.

Under NYSE rules, our common stock will continue to be traded on the NYSE during this period, subject to our compliance with other applicable continued listing requirements.

The NYSE notification does not affect our business operations, SEC reporting requirements or debt obligations.

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 2016 Annual Meeting of Stockholders to be filed with the Securities and Exchange Commission (SEC) within 120 days of the fiscal year ended December 31, 2015 where it appears under the caption ''Corporate Governance—General Overview,'' ''—Our Board of Directors,'' ''—Committees of the Board—Audit Committee,'' ''Stock Ownership Information—Section 16(a) Beneficial Ownership Reporting Compliance'' and ''Stockholder Proposals and Other Company Information—Stockholder Proposals and Director Nominations.'' The list of our executive officers and related information under ''Executive Officers'' set forth in Part I of this Annual Report on Form 10-K is incorporated by reference herein.

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 for the 2016 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2015 where it appears under the caption ''Compensation Discussion and Analysis'' and ''Compensation Committee Interlocks and Insider Participation.'' Pursuant to the rules and regulations under the Exchange Act, the information under the caption ''Compensation Discussion and Analysis—Compensation Committee Report'' 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 for the 2016 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2015 where it appears under the caption ''Stock Ownership Information—Security Ownership of Directors, Management and Certain Beneficial Holders.'' See also the information under ''Securities Authorized for Issuance Under Equity Compensation Plans'' in Part II, Item 5 of this report.

ITEM 13 CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated by reference to our Proxy Statement for the 2016 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2015 where it appears under the caption ''Certain Relationships and Related Transactions'' (except under the subheading ''—Policies and Procedures'') and ''Corporate Governance—Director Independence Determinations.''

ITEM 14 PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated by reference to our Proxy Statement for the 2016 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2015 where it appears under the caption ''Proposals Requiring Your Vote—Proposal 2: Ratification of the Appointment of the Independent Registered Public Accounting Firm.''

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 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 4.1 to the Registrant's Registration Statement on Form S-8 filed November 26, 2014 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	Stockholder's and Registration Rights Agreement (filed as Exhibit 10.1 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
4.2	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).

Exhibit Number	Exhibit Description
4.3	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 therein by reference).
4.4	Guarantor Supplemental Indenture dated as of March 5, 2015, among California Resources Corporation, CRC Construction Services, LLC, certain other guarantors 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).
4.5	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).
4.6	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).
4.7	Form of 5% Senior Note due 2020 (included in Exhibit 4.2).
4.8	Form of 5½% Senior Note due 2021 (included in Exhibit 4.2).
4.9	Form of 6% Senior Note due 2024 (included in Exhibit 4.2).
4.10	Form of 8% Senior Secured Second Lien Note due 2022 (included in Exhibit 4.1).
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).
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).

Exhibit Number	Exhibit Description
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 10.1 to the Registrant's Current Report on Form 8-K filed February 23, 2016, and incorporated herein by reference).
10.5	Transition Services Agreement 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).
10.6	Tax Sharing Agreement 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).
10.7	Employee Matters Agreement 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).
10.8	Intellectual Property License Agreement 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).
10.9	Area of Mutual Interest Agreement 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).
10.10	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).
10.11	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).
10.12	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).
10.13	Confidentiality and Trade Secret Protection Agreement 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).

Exhibit Number	Exhibit Description
	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.
10.14	California Resources Corporation Long-Term Incentive Plan Performance Stock Unit Award Terms and Conditions (filed as Exhibit 10.2 to the Registrant's Current Report on Form 10-Q filed November 6, 2015, and incorporated herein by reference).
10.15	California Resources Corporation Long-Term Incentive Plan Restricted Stock Unit Award Terms and Conditions (filed as Exhibit 10.3 to the Registrant's Current Report Form 10-Q filed November 6, 2015, and incorporated herein by reference).
10.16	California Resources Corporation Long-Term Incentive Plan Nonstatutory Stock Option Award Terms and Conditions (filed as Exhibit 10.4 to the Registrant's Current Report Form 10-Q filed November 6, 2015, and incorporated herein by reference).
10.17	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).
10.18*	First Amendment to California Resources Corporation Supplemental Savings Plan.
10.19	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).
10.20	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).
10.21	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).
10.22*	Acknowledgment of Amendment to Long-Term Incentive Award Terms and Conditions with William E. Albrecht
10.23	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).
10.24	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).
10.25	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).
10.26	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).

Exhibit Number	Exhibit Description
10.27	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).
10.28	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).
10.29	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).
10.30	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).
10.31	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).
10.32	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).
10.33	Form of Retention Letter Assignment and Assumption Agreement (filed as Exhibit 10.20 to Amendment No. 3 to the Company's Registration Statement on Form 10 filed September 22, 2014, and incorporated herein by reference).
10.34	Bonus Acknowledgement Agreement between Occidental Petroleum Corporation and William E. Albrecht (filed as Exhibit 10.21 to Amendment No. 3 to the Company's Registration Statement on Form 10 filed September 22, 2014, and incorporated herein by reference).
10.35	Retention and Separation Arrangement with Todd A. Stevens (filed as Exhibit 10.22 to Amendment No. 3 to the Company's Registration Statement on Form 10 filed September 22, 2014, and incorporated herein by reference).
10.36	Retention and Separation Arrangement with William E. Albrecht (filed as Exhibit 10.23 to Amendment No. 3 to the Company's Registration Statement on Form 10 filed September 22, 2014, and incorporated herein by reference).
10.37	Retention and Separation Arrangement with Robert A. Barnes (filed as Exhibit 10.24 to Amendment No. 3 to the Company's Registration Statement on Form 10 filed September 22, 2014, 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.

Exhibit Number	Exhibit Description
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, 2015.
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 29, 2016

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 29, 2016
/s/ Marshall D. Smith Marshall D. Smith	Senior Executive Vice President and Chief Financial Officer	February 29, 2016
/s/ Roy Pineci Roy Pineci	Executive Vice President—Finance and Principal Accounting Officer	February 29, 2016
/s/ William E. Albrecht William E. Albrecht	Executive Chairman of the Board	February 29, 2016
/s/ Justin A. Gannon Justin A. Gannon	Director	February 29, 2016
/s/ Ronald L. Havner Ronald L. Havner	Director	February 29, 2016
/s/ Catherine Kehr Catherine Kehr	Director	February 29, 2016
/s/ Harold M. Korell Harold M. Korell	Director	February 29, 2016
/s/ Richard W. Moncrief Richard W. Moncrief	Director	February 29, 2016
/s/ Avedick B. Poladian Avedick B. Poladian	Director	February 29, 2016
/s/ Robert V. Sinnott Robert V. Sinnott	Director	February 29, 2016
/s/ Timothy J. Sloan Timothy J. Sloan	Director	February 29, 2016

EXHIBIT INDEX

EXHIBITS

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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.

Annual Meeting

California Resources Corporation's annual meeting of stockholders will be held at 11:00 a.m. on May 4, 2016, at the Bakersfield Marriott at the Convention Center, 801 Truxtun Avenue, Bakersfield, CA 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.

Dividend Information

We have suspended our dividend until further notice. Payment of future dividends, if any, will be at the discretion of our board of directors.

Auditors

KPMG LLP, Los Angeles, California

Transfer Agent & Registrar

American Stock Transfer and Trust Company, LLC
Shareholder Services
6201 15th Avenue, Brooklyn, NY 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

Robert A. Barnes
Executive Vice President, Northern Operations

Shawn M. Kerns
Executive Vice President, Corporate Development

Frank E. Komin
Executive Vice President, Southern Operations

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, Exploration

Board of Directors

William E. Albrecht
Executive Chairman of the Board, California Resources Corporation

Justin A. Gannon
Former Regional Managing Partner, Grant Thornton LLP

Ronald L. Havner, Jr.
Chairman of the Board, President and Chief Executive Officer, Public Storage

Catherine A. Kehr
Former Senior Vice President and Director, Capital Research Company, The Capital Group Companies

Harold M. Korell
Lead Independent Director; Former Chairman of the Board, Southwestern Energy Company

Richard W. Moncrief
President and Chairman of the Board, Moncrief Oil International, Inc.

Avedick B. Poladian
Executive Vice President and Chief Operating Officer, Lowe Enterprises, Inc.

Robert V. Sinnott
President, Chief Executive Officer and Chief Investment Officer, Kayne Anderson Capital Advisors, L.P.

Timothy J. Sloan
President and Chief Operating Officer, Wells Fargo & Company

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

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