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, 2019
☐ **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.)
27200 Tourney Road, Suite 200	
Santa Clarita, California	**91355**
(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	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock	CRC	New York Stock Exchange

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

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

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

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

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

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

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

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

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

The aggregate market value of the voting common stock held by nonaffiliates of the registrant was approximately $945 million, computed by reference to the closing price on the New York Stock Exchange composite tape of $19.68 per share of Common Stock on June 30, 2019. 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, 2020, there were 49,175,843 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 2020 Annual Meeting of Stockholders, are incorporated by reference into Part III of this Form 10-K.

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PART I

ITEMS 1 & 2 BUSINESS AND PROPERTIES

Business Overview and History

We are an independent oil and natural gas exploration and production company operating properties exclusively within the state of California. We are the largest oil and natural gas producer in California on a gross operated basis, with average net production of 128 thousand barrels of oil equivalent per day (MBoe/d) in 2019. We have the largest privately held mineral acreage position in the state, consisting of approximately 2.2 million net mineral acres spanning four of California's major oil and natural gas basins. Our proved reserves totaled an estimated 644 million barrels of oil equivalent (MMBoe) at December 31, 2019.

We have a diversified portfolio of oil and natural gas locations and extensive drilling inventory that are economically viable in a variety of operating and commodity-price conditions, including many that are high-value projects throughout the commodity-price cycle. Our acreage position contains numerous development and growth opportunities due to its varied geologic characteristics and thousands of feet of multiple stacked-pay reservoirs in many locations. Our returns are enhanced relative to our peers because we do not make any significant royalty or other lease payments on over 60% of our mineral acreage, which is held by us in fee.

Our large portfolio of low-risk and low-decline conventional opportunities comprises approximately 73% of our proved reserves across the four oil and natural gas basins in which we operate. We are in various phases of developing many of our conventional assets, which we expect to continue to develop by using internally generated cash flow and capital raised through joint ventures.

We also own or control a network of strategically placed infrastructure that integrates with and complements our operations, to maximize the value generated from our production. This infrastructure includes natural gas processing plants, power plants, oil and natural gas gathering systems and other related assets.

Our 3D seismic library covers approximately 4,950 square miles, representing approximately 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. We have successfully implemented various exploration, drilling, completion and enhanced recovery technologies to increase recoveries, growth and value from our portfolio.

We were formed in April 2014 and are currently listed on the New York Stock Exchange. All references to ''CRC,'' the ''Company,'' ''we,'' ''us'' and ''our'' refer to California Resources Corporation and its subsidiaries.

Business Strategy

We provide ample, affordable and reliable energy, in a safe and responsible manner, to support and enhance the quality of life for Californians and the local communities where we operate. We do this through the development of our broad portfolio of assets while adhering to our commitment to making value-based capital investments. Our long-term, value-driven growth strategy is focused on five key priorities:

- Utilize our technical knowledge and experience to focus on production, delineate expansion areas and optimize hydrocarbon recovery;
- Use our Value Creation Index (VCI) metric to ensure consistent, disciplined and effective capital allocation;
- Optimize operational performance through streamlined processes, application of technology and entrepreneurial thinking to capture efficiencies, improve results and reduce costs;
- Strengthen our balance sheet by reducing absolute levels of our debt and fixed charges, investing to grow cash flow, simplifying our capital structure and pursuing value-accretive transactions, including joint ventures; and
- Maintain a proactive and collaborative approach to safety, environmental protection and community outreach while helping California meet its energy and water needs sustainably with local resources.

Strengths

The following strengths position us to successfully execute our business strategy:

- ***Operational control over our diverse asset base provides us with flexibility.***

  We have ownership or operational control over substantially all our assets. This allows us to adapt our investments by selecting drilling locations, the timing of development and the drilling and completion techniques used in a manner designed to generate free cash flow over a wide range of commodity prices.

  We have a large and diverse mineral acreage position that permits a variety of recovery mechanisms and product types. The majority of our interests are in producing properties located in reservoirs that we believe have long-lived production profiles with repeatable development opportunities. The low base decline of our conventional assets allows us to limit production declines with minimal investment.

  We are designing a carbon dioxide (CO_2) capture and sequestration (CCS) project at our Elk Hills field. The U.S. Department of Energy has awarded financial support for a Front End Engineering and Design (FEED) study to capture CO_2 produced at our Elk Hills power plant, which we are conducting in partnership with the Electric Power Research Institute. Further, with our significant land holdings in California, we have undertaken initiatives to unlock additional value from our surface acreage, including pursuing renewable energy opportunities, agricultural activities and other commercial uses.

- ***Largest mineral acreage position in a world-class oil and natural gas province.***

  Our operations are located exclusively in California, which is one of the most prolific oil and natural gas producing regions in the world and is currently the seventh largest oil producing state in the nation. According to information through 2018 from the California Department of Conservation Geologic Energy Management Division (CalGEM), formerly the Division of Oil, Gas, and Geothermal Resources, cumulative California production from all four basins in which we operate is 36 billion barrels of oil equivalent (BBoe), including approximately 20 BBoe in the San Joaquin basin, 11 BBoe in the Los Angeles basin, 3 BBoe in the Ventura basin and 2 BBoe in the Sacramento basin. Additionally, Kern County, located in the San Joaquin basin, is the fifth largest oil producing county in the lower 48 states. California is also the nation's largest state economy, and the world's fifth largest, with energy demands that significantly exceed local supply. Our large mineral acreage position and diverse development portfolio enable us to pursue the appropriate production strategy for the relevant commodity-price environment without the need to acquire new mineral acreage. We also seek to quickly deploy the knowledge we gain in our existing operations, together with our seismic data, to other areas within our portfolio.

- ***Extensive drilling and workover portfolio focused on lower-risk conventional oil opportunities.***

  Our drilling inventory at December 31, 2019 consisted of approximately 32,280 gross (24,350 net) identified well locations, of which approximately 95% target oil. In addition, we continue to maintain our available workover projects that typically deliver high returns. Our inventory of predominantly lower-risk conventional development opportunities has increased more than our unconventional opportunities. In a sustained favorable oil and natural gas price environment, we believe we can achieve further long-term production growth through the development of unconventional reservoirs. In addition, our large conventional and unconventional portfolio can provide attractive joint venture opportunities.

- ***Proven operational management and technical teams with extensive experience operating in California.***

  The members of our operational management and technical teams have an average of over 26 years of experience in the oil and natural gas industry, with an average of over 17 years focused on our California oil and natural gas operations through different price cycles. Our teams have a proven track record of applying modern technologies and operating methods to develop our assets and improve their operating efficiencies.

Operations

The following table highlights key information about our operations in the four California oil and natural gas basins in which we operate as of and for the year ended December 31, 2019:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total Operations
Mineral Acreage:					
Net mineral acreage (thousands)	1,390	30	232	512	2,164
Average net mineral acreage held in fee (%)	67%	46%	79%	37%	61%
Number of fields	48	8	27	53	136
Average net revenue interest (%)[(a)]	92%	72%	84%	76%	86%
Average drilling rigs[(b)]	7	1	—	—	8
Net wells drilled and completed	117.8	25.2	2.0	2.4	147.4
Proved reserves:					
Oil (MMBbl)	280	168	35	—	483
NGLs (MMBbl)	49	—	3	—	52
Natural gas (Bcf)	525	13	26	90	654
Total (MMBoe)	417	170	42	15	644
Oil percentage of proved reserves	67%	99%	83%	—%	75%
Production:					
Total production (MMBoe)	34	9	2	2	47
Average daily production (MBoe/d)	94	24	5	5	128
Oil percentage of production	55%	100%	80%	—%	63%
Reserves to production ratio (years)[(c)]	12.3	18.9	21.0	7.5	13.7

Note: MMBbl refers to millions of barrels; Bcf refers to billions of cubic feet; MMBoe refers to millions of barrels of oil equivalent; and MBoe/d refers to thousands of barrels of oil equivalent (Boe) per day. Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of natural gas to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

(a) The average net revenue interest represents our interest in production after considering royalties and similar burdens and third-party working interests.

(b) Includes one internally funded rig and seven JV rigs.

(c) Calculated as total proved reserves as of December 31, 2019 divided by total production for the year ended December 31, 2019.

San Joaquin Basin

The San Joaquin basin contains some of the largest oil fields in the United States based on cumulative production and proved reserves. Commercial petroleum development in the basin began in the 1800s. The basin contains multiple stacked formations throughout its areal extent, and we believe that the San Joaquin basin provides appealing opportunities for field re-development of existing wells, as well as new discoveries and unconventional play potential. The complex geology in the San Joaquin basin has allowed continuing discoveries of stratigraphic and structural traps. Approximately 75% of California's total daily oil production for 2018 was produced in the San Joaquin basin, according to CalGEM.

We hold substantially all the working, surface and mineral interests in the Elk Hills field, our largest producing asset and one of the largest fields in the continental U.S. based on proved reserves.

At Elk Hills we also operate efficient natural gas processing facilities, including a state-of-the-art cryogenic gas plant, with a combined gas processing capacity of over 520 MMcf/d. Additionally, the Elk Hills power plant generates sufficient electricity to operate the field, and sells excess power to the grid and to a utility. Our operations at Elk Hills also include an advanced central control facility and remote automation control on over 95% of our producing wells.

We believe our extensive 3D seismic library, which covers over 850,000 acres in the San Joaquin basin, or approximately 50% of our gross mineral acreage in this basin, gives us a competitive advantage in field development and further exploration. We have a large ownership interest in several of the largest existing oil fields in the San Joaquin basin, including Elk Hills, Buena Vista and Kettleman North Dome. We have also been successfully developing steamfloods in our Kern Front operations.

Los Angeles Basin

This 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.

The Wilmington field has been one of the largest fields in the continental U.S. based on proved reserves. Most of our Wilmington production is subject to a set of contracts similar to production-sharing contracts (PSCs) under which we recover the capital and operating costs we incur on behalf of the state and the city of Long Beach and receive our share of profits.

Ventura Basin

The Ventura Basin is the oldest operating oil basin in California extending from northern Los Angeles County to the coastal area of Ventura. The earliest discoveries were mines dug into hillsides to mine active oil seeps. The first commercial oil well started in 1866. The entire sedimentary section is productive at various locations, and most reservoirs are sandstones with favorable porosity and permeability. As of December 31, 2019, we operated more than 20 oil fields in this historic and prolific basin. The basin contains multiple stacked formations and provides an appealing inventory of existing field re-development opportunities, as well as new exploration potential. We continue to explore over 10,000 feet of proven stacked oil reservoirs throughout the basin.

Sacramento Basin

The Sacramento basin is a deep, thick sequence of sedimentary deposits within an elongated northwest-trending structural feature covering about 7.7 million acres. Exploration and development in the basin began in 1918. Our significant mineral acreage position in the Sacramento basin gives us the option for future development and rapid production growth in an attractive natural gas price environment.

Mineral Acreage

The following table sets forth certain information regarding the total developed and undeveloped mineral acreage in which we held an interest as of December 31, 2019. Approximately 60% of our total net mineral interest position is held in fee, approximately 17% is held by production and the remainder is subject to term leases.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in thousands)		
Developed[(a)]					
Gross[(b)]	426	21	63	266	776
Net[(c)]	349	16	61	247	673
Undeveloped[(d)]					
Gross[(b)]	1,275	17	204	348	1,844
Net[(c)]	1,041	14	171	265	1,491
Total					
Gross[(b)]	1,701	38	267	614	2,620
Net[(c)]	1,390	30	232	512	2,164

(a) Mineral acres spaced or assigned to productive wells.
(b) Total number of mineral acres in which interests are owned.
(c) Net mineral acreage includes acreage reduced to our fractional ownership interest and interests under PSC-type contracts.
(d) Mineral 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 mineral acreage contains proved reserves.

Our oil and natural gas leases have primary terms ranging from one to ten years. Once production commences, leases are extended on the producing acreage through the end of their producing life.

Work programs are designed to ensure that the exploration potential of any leased property is evaluated before expiration. In some instances, we may relinquish leased acreage in advance of the contractual expiration date if the evaluation process is complete and there is no longer a commercial reason for leasing that acreage. In cases where we determine we want to take the additional time required to fully evaluate undeveloped acreage, we have generally been successful in obtaining extensions. The combined net acreage covered by leases expiring in the next three years represented approximately 15% of our total net undeveloped acreage at December 31, 2019 and these expirations, should they occur, 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.

Production, Price and Cost History

The following table sets forth information regarding our production, average realized and benchmark prices and production costs per Boe for the years ended December 31, 2019, 2018 and 2017. For additional information on production and prices, see information set forth in *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Production and Prices*.

	Year Ended December 31,		
	2019	**2018**	**2017**
Average daily production:			
Oil (MBbl/d)	80	82	83
NGLs (MBbl/d)	15	16	16
Natural gas (MMcf/d)	197	202	182
Total daily production (MBoe/d)[a][b]	128	132	129
Total production (MMBoe)[a][b]	47	48	47
Average realized prices:			
Oil with hedge ($/Bbl)	$ 68.65	$ 62.60	$ 51.24
Oil without hedge ($/Bbl)	$ 64.83	$ 70.11	$ 51.47
NGLs ($/Bbl)	$ 31.71	$ 43.67	$ 35.76
Natural gas without hedge ($/Mcf)	$ 2.87	$ 3.00	$ 2.67
Average benchmark prices:			
Brent oil ($/Bbl)	$ 64.18	$ 71.53	$ 54.82
WTI oil ($/Bbl)	$ 57.03	$ 64.77	$ 50.95
NYMEX gas ($/MMBtu)	$ 2.67	$ 2.97	$ 3.09
Production costs per Boe[b]:			
Production costs	$ 19.16	$ 18.88	$ 18.64
Production costs, excluding effects of PSC-type contracts[c]	$ 17.70	$ 17.47	$ 17.48

Note: Bbl refers to barrels; MBbl/d refers to thousands of barrels per day; MMcf/d refers to millions of cubic feet per day; MMBtu refers to millions of British Thermal Units.

(a) Our April 2018 acquisition of the remaining working interest in the Elk Hills unit added approximately 10 MBoe/d and 8 MBoe/d in 2019 and 2018, respectively. Our divestiture of a 50% working interest in certain zones within our Lost Hills field resulted in a decrease of approximately 2 MBoe/d beginning in May 2019. PSC-type contracts had no impact on our oil production in 2019 compared to 2018. Our PSC-type contracts negatively impacted our oil production in 2018 by over 1 MBoe/d compared to 2017.

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

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

The following table sets forth information regarding production, realized prices and production costs per Boe for our two largest fields, Elk Hills and Wilmington, for the years ended December 31, 2019, 2018 and 2017:

	Elk Hills			Wilmington		
	2019	2018	2017	2019	2018	2017
Average daily production:						
Oil (MBbl/d)	22	22	19	20	21	23
NGLs (MBbl/d)	12	12	13	—	—	—
Natural gas (MMcf/d)	103	108	95	1	1	1
Total production (MBoe/d)	51	52	48	20	21	23
Average realized prices[(a)]:						
Oil (MBbl/d)	$ 68.33	$ 73.98	$ 55.58	$ 61.99	$ 67.81	$ 49.87
NGLs (MBbl/d)	$ 31.62	$ 43.58	$ 36.26	$ —	$ —	$ —
Natural gas (MMcf/d)	$ 2.67	$ 2.87	$ 2.52	$ 2.06	$ 1.71	$ 2.12
Production costs per Boe[(b)]	$ 12.55	$ 12.07	$ 11.76	$ 31.12	$ 29.81	$ 27.91
Production costs per Boe, excluding effects of PSC-type contracts[(c)]	N/A	N/A	N/A	$ 21.69	$ 21.02	$ 21.59

(a) Excludes the effect of hedges.
(b) Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of natural gas to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.
(c) The reporting of our PSC-type contracts creates a difference between reported production costs, which are for the full field, and reported volumes, which are only our net share, inflating the per barrel production costs. These amounts represent production costs after adjusting for the excess costs attributable to PSC-type contracts.

Oil, NGLs and natural gas are commodities, and the price 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 domestic and global supply and demand; domestic and global inventory levels; political and economic conditions; the actions of Organization of the Petroleum Exporting Countries (OPEC) and other significant producers and governments; changes or disruptions in actual or anticipated production, refining and processing; worldwide drilling and exploration activities; government energy policies and regulations, including with respect to climate change; the effects of conservation; weather conditions and other seasonal impacts; speculative trading in derivative contracts; currency exchange rates; technological advances; transportation and storage capacity, bottlenecks and costs in producing areas; the price, availability and acceptance of alternative energy sources; regional market conditions and other matters affecting the supply and demand dynamics for these products, along with market perceptions with respect to all of these factors. Given the volatile oil price environment, as well as our leverage, we have a hedging program to help protect our cash flow, operating margin and capital program, while maintaining adequate liquidity.

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

Our share of production and reserves from operations in the Wilmington field is subject to contractual arrangements similar to PSC-type 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 a portion of such capital and production costs and an additional share for profit. Our portion of the production represents volumes: (i) to recover our partners’ share of capital and production costs that we incur on their behalf, (ii) for our share of contractually defined base production, and (iii) for our share of remaining production thereafter. We generate returns through our defined share of production from (ii) and (iii) above. These contracts do not transfer any right of ownership to us and reserves reported from these arrangements are based on our economic interest as defined in the contracts. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline, assuming comparable capital investment and production costs. However, our net economic benefit is greater when product prices are higher. These PSC-type contracts represented 15% of our production for the year ended December 31, 2019.

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

Reserves

Volatility in oil prices may materially affect the quantities of oil and natural gas reserves we can economically produce over the longer term. At December 31, 2019, our total estimated proved reserves were 644 million barrels of oil equivalent (MMBoe), a decrease of 68 MMBoe from 712 MMBoe at December 31, 2018. During 2019, proved crude oil reserves decreased by 47 million barrels (MMBbl), proved NGL reserves decreased by 8 MMBbl and proved natural gas reserves decreased by 80 billion cubic feet or 13 MMBoe, in each case from December 31, 2018.

The information with respect to our estimated reserves presented below has been prepared in accordance with the rules and regulations of the United States Securities and Exchange Commission (SEC).

Proved oil, NGLs and natural gas reserves were estimated using the unweighted arithmetic average of the first-day-of-the-month price for each month within the year (SEC Prices), unless prices were defined by contractual arrangements. Oil, NGLs and natural gas prices used for this purpose were based on spot prices, adjusted for price differentials to account for gravity, quality and transportation costs. For our 2019 reserves estimates, the average benchmark Brent oil price was $63.15 per barrel and the average NYMEX gas price was $2.58 per MMBtu. The average realized prices used for our 2019 reserves were $63.50 per barrel for oil, $30.91 per barrel for NGLs and $2.88 per Mcf for natural gas.

The following table sets forth our net operating and non-operating interests in quantities of proved developed and undeveloped reserves of oil (including condensate), natural gas liquids (NGLs) and natural gas as of December 31, 2019. Estimated reserves include our economic interests under arrangements similar to PSCs at our Wilmington field in Long Beach.

	As of December 31, 2019				
	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Proved developed reserves:					
Oil (MMBbl)	212	121	24	—	357
NGLs (MMBbl)	43	—	2	—	45
Natural Gas (Bcf)	444	10	19	70	543
Total (MMBoe)[(a)(b)]	329	123	29	12	493
Proved undeveloped reserves:					
Oil (MMBbl)	68	47	11	—	126
NGLs (MMBbl)	6	—	1	—	7
Natural Gas (Bcf)	81	3	7	20	111
Total (MMBoe)[(b)]	88	47	13	3	151
Total proved reserves:					
Oil (MMBbl)	280	168	35	—	483
NGLs (MMBbl)	49	—	3	—	52
Natural Gas (Bcf)	525	13	26	90	654
Total (MMBoe)[(b)]	417	170	42	15	644

(a) As of December 31, 2019, approximately 24% of proved developed oil reserves, 11% of proved developed NGLs reserves, 13% of proved developed natural gas reserves and, overall, 21% of total proved developed reserves are non-producing. A majority of our non-producing reserves relate to steamfloods and waterfloods where full peak production response has not yet occurred due to the nature of such projects.

(b) Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of gas to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

Changes to Proved Reserves

The components of the changes to our proved reserves during the year ended December 31, 2019 were as follows:

	San Joaquin Basin	Los Angeles Basin[(a)]	Ventura Basin	Sacramento Basin	Total
			(in MMBoe)		
Balance at December 31, 2018	478	175	48	11	712
Revisions related to price	(8)	(11)	(1)	—	(20)
Revisions related to performance	4	11	(3)	4	16
Removal of PUDs	(41)	(2)	—	—	(43)
Extensions and discoveries	25	6	—	2	33
Improved recovery	3	—	—	—	3
Divestitures	(10)	—	—	—	(10)
Production	(34)	(9)	(2)	(2)	(47)
Balance at December 31, 2019	417	170	42	15	644

Note: Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of natural gas and one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

(a) Includes proved reserves related to PSC-type contracts of 125 MMBoe and 131 MMBoe at December 31, 2019 and 2018, respectively.

Price-related revisions – We had negative price-related revisions of 20 MMBoe primarily resulting from a lower commodity-price environment in 2019 compared to 2018.

Performance-related revisions **–** We had 16 MMBoe of net positive performance-related revisions. We added 23 MMBoe primarily related to better-than-expected performance in the San Joaquin and Los Angeles basins and 18 MMBoe that had been previously removed due to budgeting and development timing. These volumes were brought back into our reserves based on re-evaluation of the applicable areas and management's plans. These positive revisions were partially offset by 25 MMBoe in negative performance-related revisions primarily related to delayed responses in certain waterflood and steamflood projects.

Removal of PUDs – We removed 43 MMBoe of PUD reserves, of which 19 MMBoe related to expired projects not developed within the five-year window as the result of lower-than-anticipated product prices. The remaining 24 MMBoe had not yet expired but were no longer prioritized in our development plans in the current commodity price environment. The majority of these PUDs that were downgraded at management's discretion are located in the San Joaquin basin, meet economic investment criteria at current prices and are anticipated to be developed in the future.

Extensions and discoveries – We added 33 MMBoe from extensions and discoveries, primarily resulting from successful drilling in the San Joaquin and Los Angeles basins.

Improved recovery – We also added 3 MMBoe from improved recovery through Improved Oil Recovery (IOR) and Enhanced Oil Recovery (EOR) methods, which were associated with the continued development of steamflood and waterflood properties in the San Joaquin basin.

Divestitures – We had a reduction of 10 MMBoe in connection with the Lost Hills divestiture and the Alpine JV entered into during the year. See *Part II, Item 7 Management's Discussion and Analysis, Acquisitions and Divestitures* for more on the Lost Hills divestiture and *Part II, Item 7 Management's Discussion and Analysis, Joint Ventures* for more on the Alpine JV.

We achieved an organic reserve replacement ratio of 111% from our capital program of $455 million, including 16 MMBoe of net positive performance-related revisions. For further information on our organic reserve replacement ratio, see the *PV-10, Standardized Measure and Reserve Replacement Ratio* section below.

Proved Undeveloped Reserves

The total changes to our PUDs during the year ended December 31, 2019 were as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in MMBoe)		
Balance at December 31, 2018	123	43	15	1	182
Revisions related to price	(1)	(5)	—	—	(6)
Revisions related to performance	8	9	(2)	1	16
Removal of PUDs	(41)	(2)	—	—	(43)
Extensions and discoveries	18	5	—	1	24
Improved recovery	2	—	—	—	2
Divestitures	(6)	—	—	—	(6)
Transfers to proved developed reserves	(15)	(3)	—	—	(18)
Balance at December 31, 2019	88	47	13	3	151

Note: Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of natural gas and one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

Price-related revisions – We had negative price-related revisions of 6 MMBoe primarily resulting from a lower commodity-price environment in 2019 compared to 2018.

Performance-related revisions – We had 16 MMBoe of net positive performance-related revisions. We added 21 MMBoe that were previously removed due to budgeting and development timing. These volumes were brought back into our reserves based on re-evaluation of the applicable areas and management's plans. These positive revisions were partially offset by 5 MMBoe in negative performance-related revisions primarily related to a waterflood in the Ventura basin.

Removal of PUDs – We removed a total of 43 MMBoe of PUD reserves in 2019, of which 19 MMBoe related to expired projects not developed within the five-year window as the result of lower-than-anticipated oil prices. The remaining 24 MMBoe had not yet expired but were no longer prioritized in our development plans at lower-than-anticipated prices. The majority of these PUDs that were downgraded at management's discretion are located in the San Joaquin basin, meet economic investment criteria at current prices and are anticipated to be developed in the future.

Extensions and discoveries – We added 24 MMBoe of PUDs through extensions and discoveries, primarily resulting from successful drilling efforts in the San Joaquin and Los Angeles basins.

Improved recovery – We added proved reserves of 2 MMBoe from improved recovery through IOR and EOR methods. The improved recovery additions were associated with the continued development of steamflood and waterflood properties in the San Joaquin basin. Approximately 77% of the PUD additions from extensions and discoveries and improved recovery were crude oil.

Divestitures – We had a reduction of 6 MMBoe in connection with the Lost Hills divestiture and the Alpine JV entered into during the year. See *Part II, Item 7 Management's Discussion and Analysis, Acquisitions and Divestitures* for more on the Lost Hills divestiture and *Part II, Item 7 Management's Discussion and Analysis, Joint Ventures* for more on the Alpine JV.

Transfers to proved developed reserves – We converted 18 MMBoe of PUDs to proved developed reserves, the majority of which were in the San Joaquin and Los Angeles basins. As a result, we converted approximately 10% of our beginning-of-year PUDs, after adjusting for volumes divested during the year, to proved developed reserves during the year, investing approximately $248 million of drilling and completion capital.

Our year-end development plans and associated PUDs are consistent with SEC guidelines for development within five years. We believe we will have sufficient capital to develop all year-end 2019 PUDs within five years of their original booking date. Management's capital commitment assumes an average $65 Brent price for 2020, $72 for 2021 and approximately $75 thereafter. Prices that are significantly below these levels for a prolonged period could require us to reduce expected capital investment over the next five years, potentially impacting either the quantity or the development timing of proved undeveloped reserves. For example, if the average future price remained at $65 Brent, our volumes ultimately recovered from PUDs would be reduced by approximately 5% to 10% over the long term.

PV-10, Standardized Measure and Reserve Replacement Ratio

As of December 31, 2019, our standardized measure of discounted future net cash flows (Standardized Measure) was $5.2 billion and PV-10 was approximately $6.8 billion.

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 Prices. PV-10 differs from Standardized Measure because Standardized Measure includes the effects of future income taxes on future net cash flows. Neither PV-10 nor Standardized Measure should be construed as the fair value of our oil and natural gas reserves. Standardized Measure is prescribed by the SEC as an industry standard asset value measure to compare reserves with consistent pricing, costs and discount assumptions. PV-10 facilitates the comparisons to other companies as it is not dependent on the tax-paying status of the entity.

	As of December 31, 2019 (in millions)
Standardized measure of discounted future net cash flows	$ 5,231
Present value of future income taxes discounted at 10%	1,618
PV-10 of proved reserves	$ 6,849
Organic reserve replacement ratio[(a)]	111%

(a) The organic reserve replacement ratio is calculated for a specified period using the proved oil-equivalent additions from extensions and discoveries, improved recovery and net performance-related revisions, divided by oil-equivalent production. There is no guarantee that historical sources of reserves additions will continue as many factors are fully or partially outside management's control, including commodity prices, availability of capital and the underlying geology, all of which affect reserves additions. Management uses this measure to gauge the results of its capital program. Other oil and natural gas producers may use different methods to calculate replacement ratios, which may affect comparability.

Reserves Evaluation and Review Process

Our estimates of proved reserves and associated discounted future net cash flows as of December 31, 2019 were made by our technical personnel, such as reservoir engineers and geoscientists, with the assistance of operational and financial personnel and are the responsibility of management. The estimation of proved reserves is based on the requirement of reasonable certainty of economic producibility and management's funding commitments to develop the reserves. Reserves volumes are estimated by forecasts of production rates, operating costs and capital investments. Price differentials between specified benchmark prices and realized prices and specifics of each operating agreement are then applied against the SEC Price to estimate the net reserves. Production rate forecasts are derived using a number of methods, including estimates from decline-curve analysis, type-curve analysis, material balance calculations, which consider the volumes of substances replacing the volumes produced and associated reservoir pressure changes, seismic analysis and computer simulations of reservoir performance. These field-tested technologies have demonstrated reasonably certain results with consistency and repeatability in the formations being evaluated or in analogous formations. Operating and capital costs are forecast using the current cost environment (without accounting for possible cost changes) applied to expectations of future operating and development activities related to the proved reserves.

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. 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 Professional Engineer in the state of Texas.

We have an Oil and Gas Reserves Review Committee (Reserves Committee), consisting of senior corporate officers, which reviewed and approved our oil and natural gas reserves for 2019. The Reserves Committee annually reports its findings to the Audit Committee.

Audits of Reserves Estimates

Ryder Scott and Netherland, Sewell & Associates, Inc. (NSAI) were engaged to provide independent audits of our reserves estimates for our fields. Ryder Scott audited 42% of our total proved reserves, all of which were in Elk Hills. NSAI audited 38% of our total proved reserves, all from fields excluding Elk Hills. Over 95% of our total 2019 proved reserves were audited by independent auditors at some time during 2015 through 2019.

NSAI was retained by us in 2019 to audit proved reserves from our fields other than in Elk Hills due to their extensive California experience. Additionally, NSAI already performs audits on behalf of several of our partners. Engaging NSAI to audit the fields they are already familiar with provides efficiencies and facilitates interactions with our partners.

Our independent reserve engineers 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. They also examined the appropriateness of the methodologies employed to estimate our reserves as well as their categorization, using the definitions set forth by the SEC, and found them to be appropriate. As part of their process, they 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 our independent reserve engineers. Given the inherent uncertainties and judgments in estimating proved reserves, differences between our estimates and those of our independent reserve engineers are to be expected. The aggregate difference between our estimates and those of the independent auditors was less than 10%, which was within SPE's acceptable tolerance.

In the conduct of the reserves audits, our independent auditors 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 the attention of our independent auditors that brought into question the validity or sufficiency of any such information or data, they would not rely on such information or data until it had resolved its questions relating thereto or had independently verified such information or data. Our independent auditors 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. Both of our independent reserve engineers issued an unqualified audit opinion on our proved reserves as of December 31, 2019, which are attached as an exhibit to this Form 10-K.

Ryder Scott qualifications – The primary technical engineer responsible for our audit has 42 years of petroleum engineering experience, the majority of which has been in the estimation and evaluation of reserves. He serves on the Ryder Scott Board of Directors and is a registered Professional Engineer in the state of Texas.

NSAI qualifications – The two technical persons primarily responsible for our audit have over 18 years and 40 years of petroleum engineering experience, respectively. Both individuals have the education, training and experience to perform oil and gas reservoir studies and reserves evaluations.

Recovery Mechanisms

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

	Total Proved Reserves		Average Net Daily Production (MBoe/d)
	% of Total Basin	MMBoe[(a)]	Year ended December 31, 2019
San Joaquin Basin			
Primary	14%		15
Waterfloods	12%		11
Steamfloods	32%		23
Unconventional	42%		45
San Joaquin Basin		417	94
Los Angeles Basin			
Waterfloods	100%		24
Los Angeles Basin subtotal		170	24
Ventura Basin			
Primary	39%		3
Waterfloods	61%		2
Ventura Basin subtotal		42	5
Sacramento Basin			
Primary	100%		5
Sacramento Basin subtotal		15	5
Total		644	128

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

Conventional Reservoirs

We seek to optimize the potential of our conventional assets by using primary recovery methods, followed by IOR methods like waterflooding and EOR methods like steamflooding, both of which use vertical and lateral drilling. We determine which development method to use based on reservoir characteristics, reserves potential and expected returns. All of these techniques are well understood technologies that we have used extensively in California.

Primary Recovery

Primary recovery is a reservoir drive mechanism that utilizes the natural flow of the reservoir and is the first technique we use to develop a conventional reservoir. Our successful exploration program continues to provide us with primary recovery opportunities in new reservoirs or through extensions of existing fields. Our primary recovery programs create future opportunities to convert these reservoirs to waterfloods or steamfloods after their primary production phase.

Waterfloods

Some of our fields have been partially produced and no longer have sufficient energy to drive oil to our producing wellbores. Waterflooding is a well understood process that has been used in California for over 50 years to re-introduce energy to the reservoir through water injection and to sweep oil to producing wellbores. This process has been known to increase recovery factors from approximately 10% under primary recovery methods to up to approximately 20%. Our waterflood operations have attractive margins and returns. These operations typically have low and predictable production declines and allow us to extend the productive life of a reservoir and significantly increase our incremental recovery after primary recovery. As a result, investments in waterfloods can yield attractive returns even in a low oil price environment.

Steamfloods

Some of our fields contain heavy, thick oil. Steamfloods work by injecting steam into the reservoir to heat the oil which allows 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 generally requires low capital investment with attractive margins and returns even in a low oil price environment. The economics of steamflooding are largely a function of the ratio between oil and natural gas prices as gas is used to generate steam production and, therefore, offers favorable returns as long as the oil-to-gas price ratio is in excess of five. In 2019, the oil-to-gas ratio averaged over 20. After drilling, these operations typically ramp up production over one to two years as the steam continues to influence the oil production, and then exhibit a plateau for several months, with a subsequent low, predictable production decline rate of 5% to 10% per year. This gradual decline allows us to extend the productive life of a reservoir and significantly increase our incremental recovery after primary production.

Unconventional Reservoirs

We have a significant portfolio of lower permeability unconventional reservoirs that typically utilize enhanced completion techniques. 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 4,440 gross (4,420 net) unconventional drilling locations on this acreage, excluding unconventional exploration drilling locations. Approximately 35% of our 2019 production was from unconventional reservoirs, all in the San Joaquin basin. Our unconventional production from our largest field, the Elk Hills field in the San Joaquin basin, decreased approximately 6% in 2019 from the prior year. As of December 31, 2019, we had proved reserves of approximately 175 MMBoe associated with our unconventional properties, approximately 18% of which were proved undeveloped reserves.

We hold significant interests in the Monterey formation, which is divided into upper and lower intervals. Prior to the severe price declines that began in late 2014, we were focused on developing higher-value unconventional production from seven discrete stacked pay horizons within the Monterey formation, primarily within the upper Monterey. We have continued our development activities in the upper Monterey formation and delineation of the Kreyenhagen formation within our Kettleman North Dome field. During the year ended December 31, 2019, we had unconventional production of approximately 44 MBoe/d on average from the upper Monterey in the San Joaquin basin.

The lower Monterey is recognized as a world-class source rock but has an extremely limited production history compared to the upper Monterey, and therefore very limited knowledge exists regarding its potential. However, over the long term, we believe we will be able to apply knowledge we gain from the upper Monterey to the lower Monterey, Kreyenhagen and Moreno formations, which have similar geological attributes.

Drilling Locations

The table below sets forth our total gross identified drilling locations as of December 31, 2019, excluding our unconventional exploration drilling locations.

	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	90	—	8,640	—
Steamflood	730	170	7,750	450
Waterflood	120	50	1,920	1,000
Unconventional	120	—	4,440	—
San Joaquin Basin subtotal	1,060	220	22,750	1,450
Los Angeles Basin				
Primary Conventional	—	—	60	—
Waterflood	500	130	1,510	460
Los Angeles Basin subtotal	500	130	1,570	460
Ventura Basin				
Primary Conventional	30	—	1,630	—
Steamflood	—	—	90	—
Waterflood	70	60	1,560	560
Unconventional	—	—	—	—
Ventura Basin subtotal	100	60	3,280	560
Sacramento Basin				
Primary Conventional	30	—	2,210	—
Sacramento Basin subtotal	30	—	2,210	—
Total Drilling Locations	1,690	410	29,810	2,470

Note: Total gross identified drilling locations are comprised of gross proven drilling locations of 2,100 gross (1,890 net), gross unproven drilling locations of 16,270 gross (15,800 net) and gross conventional exploration drilling locations of 13,910 gross (6,660 net). Total gross identified drilling locations exclude gross unconventional exploration drilling locations of 6,400 gross (5,300 net).

Proven Drilling Locations

Based on our reserves report as of December 31, 2019, we have approximately 2,100 gross (1,890 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 reserves only after we have adopted a development plan to drill them within a five-year time frame. As a result of rigorous technical evaluation of geologic and engineering data, we can estimate with reasonable certainty that reserves from these locations will be commercially recoverable in accordance with SEC guidelines. Management considers the availability of local infrastructure, drilling support assets, state and local regulations and other factors it deems relevant in determining such locations.

Unproven Drilling Locations

We have also identified a multi-year inventory of 16,270 gross (15,800 net) drilling locations that are not associated with proved undeveloped reserves but are specifically identified on a field-by-field basis considering the applicable geologic, engineering and production data. We analyze past field development practices and identify analogous drilling opportunities taking into consideration historical production performance, estimated drilling and completion costs, spacing and other performance factors. These drilling locations primarily include (i) infill drilling locations, (ii) additional locations due to field extensions or (iii) potential IOR and EOR project expansions, some of which are currently in the pilot phase across our properties but have yet to be moved to the proven category. We believe the assumptions and data used to estimate these drilling locations are consistent with established industry practices with well spacing selected based on the type of recovery process we are using.

Exploration Drilling Locations

Conventional – Our exploration portfolio contains approximately 13,910 gross (6,660 net) unrisked prospective drilling locations in conventional reservoirs, the majority of which are located near existing producing fields. We use internally generated information and proprietary geologic models consisting of analog data, 3D seismic data, open hole and mud log data, cores and reservoir engineering data to help define the extent of the targeted intervals and the potential ability of such intervals to produce commercial quantities of hydrocarbons. Information used to identify exploration locations includes both our own proprietary data, as well as industry data available in the public domain. After defining the potential areal extent of an exploration prospect, we identify our exploration drilling locations within the prospect by applying the well spacing historically utilized for the applicable type of recovery process used in analogous fields.

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

Well Spacing Determination

Our well spacing determinations for identified well locations are based on actual operational spacing within our existing producing fields, which we believe are reasonable for the particular recovery process employed (e.g., primary, waterflood or steamflood). Due to the significant vertical thickness and multiple stacked reservoirs, 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 natural gas fields in California.

Drilling Schedule

Our identified drilling locations are either included in our drilling schedule or are expected to be scheduled in the future. When we identify these locations, we make assumptions about the consistency and accuracy of data that may prove inaccurate. For a discussion of the risks associated with our drilling program, see *Part I, Item 1A – Risk Factors – Risks Related to Our Business and Industry*.

Drilling Statistics

The following table sets forth information on our net exploration and development wells completed during the periods indicated, regardless of when drilling was initiated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total Net Wells
2019					
Productive					
Exploratory	0.3	—	—	—	0.3
Development	117.5	25.2	2.0	2.4	147.1
Dry					
Exploratory	—	—	—	—	—
Development	—	—	—	—	—
2018					
Productive					
Exploratory	0.3	—	—	—	0.3
Development	127.0	48.2	3.2	—	178.4
Dry					
Exploratory	1.3	—	0.3	—	1.6
Development	—	—	—	—	—
2017					
Productive					
Exploratory	2.0	—	—	—	2.0
Development	91.8	14.5	1.6	—	107.9
Dry					
Exploratory	3.0	—	—	—	3.0
Development	—	—	—	—	—

The following table sets forth information on our exploration and development wells where drilling was either in progress or pending completion as of December 31, 2019, which is not included in the above table.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Exploratory and development wells					
Gross[(a)]	22.0	4.0	—	2.0	28.0
Net[(b)]	—	3.6	—	0.8	4.4

(a) The total number of wells in which interests are owned, including MIRA and Alpine JV wells.
(b) Net wells include wells reduced to our fractional interest.

On a gross basis, these projects included two primary, four waterflood, eleven steamflood and eleven unconventional wells.

Productive Wells

Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Our average working interest in our producing wells is approximately 90%. Wells are categorized based on the primary product they produce.

The following table sets forth our productive oil and natural gas wells (both producing and capable of production) as of December 31, 2019, excluding wells that have been idle for more than five years:

	As of December 31, 2019			
	Productive Oil Wells		Productive Natural Gas Wells	
	Gross[(a)]	Net[(b)]	Gross[(a)]	Net[(b)]
San Joaquin Basin	8,525	7,559	160	155
Los Angeles Basin	1,457	1,410	—	—
Ventura Basin	730	726	—	—
Sacramento Basin	—	—	926	848
Total	10,712	9,695	1,086	1,003
Multiple completion wells included in the total above	248	234	45	40

(a) The total number of wells in which interests are owned.
(b) Net wells include wells reduced to our fractional interest.

Exploration Program

We have an active exploration program in both conventional and unconventional plays. We believe our experienced technical staff, proprietary geological models, mineral acreage position and extensive 3D seismic library give us a strong competitive advantage in our exploration efforts. California basins have generated billions of barrels of oil and trillions of cubic feet of natural gas and have established production from over 400 identified reservoir intervals in both structural and stratigraphic trap configurations. Historical industry activity has focused on the primary and secondary development of known hydrocarbon accumulations, many of which were discovered over a century ago. We have significant land positions in under-explored hydrocarbon reservoirs in each of California's four major oil and natural gas basins.

Our exploration program is designed to extend fields and add new trends and resource plays to our already broad portfolio, targeting new oil and natural gas accumulations and leveraging our existing infrastructure. We continue to focus on growing our exploration drilling locations and resource identification, in some cases working with JV partners, in the San Joaquin, Sacramento and Ventura Basins. We have a ranked near-field portfolio of over 150 exploration prospects across the San Joaquin, Sacramento and Ventura basins.

We have executed a deliberate approach to fund a portion of our exploration program through farmouts and joint ventures allowing us to test multiple prospects for minimal net investment. Generally, our partners fund the drilling activity in an exploration area on a promoted basis with any future development wells funded in proportion to the respective working interest percentages.

Marketing Arrangements

Crude Oil – We sell nearly all of our crude oil into the California refining markets, which offer favorable pricing for comparable grades relative to other U.S. regions. Currently, the majority of our crude oil sales contracts are index-based and have 30- to 90-day terms.

Although California state policies actively promote and subsidize renewable energy, including solar, wind, biomass and geothermal resources, the demand for oil and natural gas in California remains strong. California is heavily reliant on imported sources of energy, with approximately 72% of oil and 90% of natural gas consumed in 2019 imported from outside the state. Nearly all of the imported oil arrives via supertanker, mostly from foreign locations. As a result, California refiners have typically purchased crude oil at international waterborne-based Brent prices. We believe that the limited crude transportation infrastructure from other parts of the U.S. into California will continue to contribute to higher realizations than most other U.S. oil markets for comparable grades.

The International Maritime Organization has ruled that beginning in 2020 (IMO 2020), the marine sector will have to reduce sulfur emissions by over 80% by either switching to lower sulfur fuels or installing scrubbing facilities. The majority of the oil we produce has a lower sulfur content than the average oil produced in California and other oil imported into the state. As a result of IMO 2020, we may see an increased demand for low-sulfur crude oil, which could favorably affect our realized prices.

Substantially all of our crude oil production is connected to third-party pipelines and California refining markets via our gathering systems. We do not refine or process the crude oil we produce and do not have any significant long-term transportation arrangements.

Natural Gas – We sell all of our natural gas not used in our operations into the California markets on a monthly basis at market-based index pricing. Natural gas prices and differentials are strongly affected by local market fundamentals, such as storage capacity and the availability of transportation capacity in the market and producing areas. Transportation capacity influences prices because California imports more than 90% of its natural gas from other states and Canada. As a result, we typically enjoy favorable margins relative to out-of-state producers due to lower transportation costs on the delivery of our natural gas. Changes in natural gas prices have a smaller impact on our operating results than changes in oil prices as only approximately 25% of our total equivalent production volume and even a smaller percentage of our revenue is from natural gas.

In addition to selling natural gas, we also use natural gas for our steamfloods and power generation. As a result, the positive impact of higher natural gas prices is partially offset by higher operating costs of our steamflood projects and power generation, but higher prices still have a net positive effect on our operating results due to higher revenue. Conversely, lower natural gas prices lower the operating costs but have a net negative effect on our financial results.

We currently have sufficient firm transportation capacity contracts to transport our natural gas, where some capacity volumes vary by month. We sell virtually all of our natural gas production under individually negotiated contracts using market-based pricing on a monthly or shorter basis.

NGLs – NGL price realizations 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 and seasonality can magnify price volatility.

Our earnings are also affected by the performance of our complementary natural gas-processing plants. 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. Our natural gas-processing plants also facilitate access to third-party delivery points near the Elk Hills field.

We currently have pipeline delivery contracts to transport 16,500 barrels per day of NGLs to market. We sell virtually all of our NGLs using index-based pricing. Our NGLs are generally sold pursuant to one-year contracts that are renewed annually. Approximately 32% of our NGLs are sold to export markets. Our contracts to deliver NGLs require us to cash settle any shortfall between the committed quantities and volumes actually delivered. For one of these contracts we expect to cash settle approximately $20 million in April 2020.

Electricity – Part of the electrical output of the Elk Hills power plant operated by one of our subsidiaries is used by Elk Hills and other nearby fields, which reduces operating costs and increases reliability. We sell the excess electricity generated to the grid and a local utility. The power sold to the utility is subject to agreements through the end of 2023, which include a monthly capacity payment plus a variable payment based on the quantity of power purchased each month. The prices obtained for excess power impact our earnings but generally by an insignificant amount.

Delivery Commitments

We have short-term commitments to certain refineries and other buyers to deliver oil, natural gas and NGLs. As of December 31, 2019, we had oil and NGL delivery commitments of 51 and 17 MBbl/d through March 2020, respectively, and natural gas commitments of 29 MMcf/d through the end of 2020. We generally have significantly more production than the amounts committed for delivery and have the ability to secure additional volumes of products as needed. These are index-based contracts with prices set at the time of delivery.

Hedging

We maintain a commodity hedging program primarily focused on crude oil to help protect our cash flows, margins and capital program from the volatility of commodity prices and to improve our ability to comply with the covenants under our credit facilities. We build our commodity hedge positions to protect our downside risk without significantly limiting our upside potential, but we can give no assurances that our hedges will be adequate to accomplish our objectives. 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 accounted for as cash-flow or fair-value hedges. For more on our current derivative contracts, see *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources*.

Our Principal Customers

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

For the year ended December 31, 2019, our principal customers, Phillips 66 Company and Valero Marketing & Supply Company, each accounted for at least 10%, and collectively accounted for 46%, of our oil and natural gas sales before the effects of hedging. For the year ended December 31, 2018, our principal customers, Phillips 66 Company and Valero Marketing & Supply Company, each accounted for at least 10%, and collectively accounted for 43%, of our oil and natural gas sales before the effects of hedging. For the year ended December 31, 2017, our principal customers, Phillips 66 Company, Andeavor Logistic LP, Valero Marketing & Supply Company and Shell Trading (US) Company, each accounted for at least 10%, and collectively accounted for 67%, of our oil and natural gas sales before the effects of hedging.

Title to Properties

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

Competition

We encounter strong competition from numerous parties in the oil and natural gas industry doing business in California, ranging from small independent producers to major international oil companies. The oil market in California is a captive market with no interstate crude pipelines and only limited rail access and unloading capacity for refineries. California imports 72% of the oil it consumes and virtually all of that arrives from waterborne sources. Our proximity to the California refineries gives us a competitive advantage through lower transportation costs. Further, California refineries are generally designed to process crude with similar characteristics to the oil produced from our fields. The California natural gas market is serviced from a network of pipelines, including interstate and intrastate pipelines. We deliver our natural gas to customers using our firm capacity contracts.

We compete for third-party services to profitably develop our assets, to find or acquire additional reserves, to sell our production and to find and retain qualified personnel. Higher commodity prices could intensify competition for drilling and workover rigs, pipe, other oil field equipment and personnel. However, the California energy industry has experienced only limited cost inflation in recent years due to excess capacity in the service and supply sectors. At current commodity price levels, we expect limited cost inflation to continue in 2020. Further, our relative size and activity levels, compared to other in-state producers, favorably influences the pricing we receive from third-party providers in the local markets in which we operate.

We also face indirect competition from alternative energy sources, including wind and solar power. Competitive conditions could be affected by future legislation and regulation as California develops renewable energy and implements climate-related policies.

Infrastructure

We own or control a network of infrastructure that is integral to and complements our operations. The significant scale of our integrated infrastructure helps us connect to third-party transportation pipelines, providing us with a competitive advantage by reducing our operating costs. Our infrastructure includes the following:

Description	Quantity	Unit[(a)]	Capacity		
			San Joaquin Basin	Other Basins	Total
Gas Processing Plants	9	MMcf/d	610	50	660
Power Plants	3	MW	600	50	650
Steam Generators/Plants	>50	MBbl/d	220	—	220
Compressors	400	MHp	300	20	320
Water Management Systems	22	MBw/d	2,400	2,100	4,500
Water Softeners	30	MBw/d	265	—	265
Oil and NGL Storage		MBbls	580	660	1,240
Gathering Systems		Miles			>8,000

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

Natural Gas Processing

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

Electricity

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

Water and Steam Infrastructure

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

Gathering Systems

We own an extensive network of over 8,000 miles of oil and natural gas gathering lines. These gathering lines are dedicated almost entirely to collecting our oil and natural gas production and are in close proximity to field-specific facilities such as tank settings or central processing sites. These lines connect our producing wells and facilities to gathering networks, natural gas collection and compression systems, and water and steam processing, injection and distribution systems. Our oil gathering systems connect to multiple third-party transportation pipelines, which increases our flexibility to ship to various parties. In addition, virtually all of our natural gas facilities connect with major third-party natural gas pipeline systems. As a result of these connections, we typically have the ability to access multiple delivery points to improve the prices we obtain for our oil and natural gas production.

Oil and NGL Storage

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

Employees

We had approximately 1,250 employees as of December 31, 2019. Approximately 900 were employed in field operations, of which approximately 70 were represented by labor unions. We have not experienced any strikes or work stoppages by our employees. We also utilized the services of independent contractors to perform drilling, well work, operations, construction and other services, including construction contractors whose workforce is represented by labor unions.

Regulation of the Oil and Natural Gas Industry

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

Regulation of Exploration and Production

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

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

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

CalGEM is California's primary regulator of the oil and natural gas industry on private and state lands, with additional oversight from the State Lands Commission’s administration of state surface and mineral interests. The Bureau of Land Management (BLM) of the U.S. Department of the Interior exercises similar jurisdiction on federal lands in California, on which CalGEM also asserts jurisdiction over certain activities. Government actions, including the issuance of certain permits or approvals, by state and local agencies or by federal agencies may be subject to environmental reviews, respectively, under the California Environmental Quality Act or the National Environmental Policy Act (NEPA), which may result in delays, imposition of mitigation measures or litigation. CalGEM currently requires an operator to identify the manner in which CEQA has been satisfied prior to issuing various state permits, typically through either an environmental review or an exemption by a state or local agency. In Kern County this requirement has typically been satisfied by complying with the local oil and gas ordinance, which was supported by an Environmental Impact Report (EIR) certified by the Kern County Board of Supervisors in 2015. A group of plaintiffs challenged the EIR and on February 25, 2020, a California Court of Appeal issued a ruling that invalidates a portion of the EIR, effective in 30 days, until the County makes certain revisions to the EIR and recertifies it. This process may take several months, during which time drilling and other permits may be delayed in Kern County. We do not currently expect this process to materially affect our plans and operations at Elk Hills or other fields we operate in Kern County as the Court of Appeal's ruling does not invalidate existing permits and we maintain a robust drilling permit inventory. In addition, other governmental agencies have previously conducted several environmental reviews for activities at Elk Hills, including under NEPA and CEQA, which we believe provide additional support for continued issuance of drilling and other permits at Elk Hills.

The California Legislature has significantly increased the jurisdiction, duties and enforcement authority of CalGEM, the State Lands Commission and other state agencies with respect to oil and natural gas activities in recent years. For example, 2019 state legislation expanded CalGEM’s duties effective on January 1, 2020 to include public health and safety and reducing or mitigating greenhouse gas emissions while meeting the state’s energy needs, and will require CalGEM to study and prioritize idle wells with emissions, evaluate costs of abandonment, decommissioning and restoration, and review and update associated indemnity bond amounts from operators if warranted, up to a specified cap which may be shared among operators. Other 2019 legislation specifically addressed oil and natural gas leasing by the State Lands Commission, including imposing conditions on assignment of state leases, requiring lessees to complete abandonment and decommissioning upon the termination of state leases, and prohibiting leasing or conveyance of state lands for new oil and natural gas infrastructure that would advance production on certain federal lands such as national monuments, parks, wilderness areas and wildlife refuges.

CalGEM and other state agencies have also significantly revised their regulations, regulatory interpretations and data collection and reporting requirements. CalGEM issued updated regulations in April 2019 governing management of idle wells and underground fluid injection, which include specific implementation periods. The updated idle well management regulations require operators to either submit annual idle well management plans describing how they will plug and abandon or reactivate a specified percentage of long-term idle wells or pay additional annual fees and perform additional testing to retain greater flexibility to return long-term idle wells to service in the future. The updated underground injection regulations address injection approvals, project data requirements, testing of injection wells, monitoring and reporting requirements with respect to injection parameters, containment and incident response, among other topics. In November 2019, the State Department of Conservation issued a press release announcing three actions by CalGEM: (1) a moratorium on approval of new high–pressure cyclic steam wells pending a study of the practice to address surface expressions experienced by certain operators; (2) review and updating of regulations regarding public health and safety near oil and natural gas operations pursuant to additional duties assigned to CalGEM by the Legislature in 2019; and (3) a performance audit of CalGEM's permitting processes for well stimulation treatment (WST) permits and project approval letters for underground injection (PALs) by the State Department of Finance and an independent review and approval of the technical content of pending WST and PAL applications by Lawrence Livermore National Laboratory. While we do not use high-pressure cyclic steam injection and have not historically utilized well stimulation techniques to complete the majority of our wells, additional state regulation of exploration and production activities could result in increased operating costs or delays in or the inability to obtain permits, or otherwise adversely affect production from the underlying properties.

In 2013 California State Legislature (Legislature) enacted Senate Bill 4 (SB 4), which increased regulation of certain well stimulation techniques, including acid matrix stimulation and hydraulic fracturing, which involves the injection of fluid under pressure into underground rock formations to create or enlarge fractures to allow oil and natural gas to flow more freely into producing wells. Among other things, SB 4 requires operators to obtain specific WST permits, make detailed disclosures and implement groundwater monitoring and water management plans. After allegations of conflicts of interest by certain oil and natural gas regulators, the State Oil and Gas Supervisor was replaced, and the state has not issued new WST permits since July 2019, pending completion of Lawrence Livermore National Laboratory’s review of the technical content of each new WST permit. The U.S. Environmental Protection Agency (EPA) and the BLM also regulate certain well stimulation activities. In 2017, the BLM rescinded its nationwide hydraulic fracturing regulations; however, the rescission is subject to ongoing legal challenge. Separately, the BLM's implementation of its 2014 Resource Management Plan (RMP) for leasing of federal lands in portions of Kern, Ventura and other counties has been delayed by litigation and a settlement from a 2017 court order that required the BLM to prepare a Supplemental Environmental Impact Statement (SEIS) addressing hydraulic fracturing in greater detail. In the fourth quarter of 2019, the BLM issued the SEIS and its Record of Decision approving the 2014 RMP without changes, and the state has challenged the BLM's decision in court. The implementation of well stimulation regulations has delayed, and increased the cost of, certain operations.

Federal and state pipeline regulations have also been recently revised. CalGEM imposed more stringent inspection and integrity management requirements in 2019 and 2020 with respect to certain natural gas pipelines in specified locations, with additional regulations anticipated in 2020 regarding digital mapping of such lines. The Office of the State Fire Marshal (OSFM) has proposed regulations that are expected to take effect in 2020 to require risk assessment of various oil lines in the coastal zone, followed by retrofitting of certain of those lines with the best available control technology to mitigate oil spills over a specified implementation period. Finally, the federal Pipeline and Hazardous Materials Safety Administration issued new regulations in October 2019 expanding integrity management, leak detection and reporting requirements for liquid pipelines and natural gas transmission pipelines, with various implementation periods beginning in July 2020 and specific requirements dependent upon the characteristics of the line and its location.

In 2019, Assembly Bill 345 (AB 345) was introduced but failed to advance in the Legislature to impose a statewide setback distance of 2,500 feet between certain oil and natural gas operations and residences, schools and healthcare facilities. CalGEM is commencing public health and safety workshops in the first quarter of 2020 to be followed by an associated rulemaking process that will consider various measures, including potential land use setbacks. In January 2020, the State Assembly passed an amended version of AB 345 that, if passed by the State Senate and signed by the Governor, would require CalGEM to adopt a land use setback in its rulemaking by July 2022. As amended, the bill no longer specifies a mandatory setback distance, but would require CalGEM to consider a 2,500-foot setback as well as enhanced monitoring and maintenance requirements.

In addition, certain local governments have proposed or adopted ordinances that would restrict certain drilling activities in general and well stimulation, completion or injection activities in particular, impose setback distances from certain other land uses, or ban such activities outright. The most onerous of these local measures was adopted in 2016 by Monterey County, where we owned mineral rights but have no production. As written, the measure sought to prohibit the drilling of new oil and natural gas wells, hydraulic fracturing and other well-stimulation techniques and to phase out the injection of produced water. This measure was challenged in state court and the Monterey County Superior Court issued a decision in 2017, finding that the bans on drilling new wells and water injection are preempted by and invalid under existing state and federal regulations and, if implemented, would constitute a taking of our property and that of other mineral rights owners without compensation. The court did not rule on the ban on hydraulic fracturing because the court found that the issue was not ripe since hydraulic fracturing is not currently being conducted in Monterey County, noting that the ban could be challenged in the event a project involving hydraulic fracturing is proposed. Although the County is complying with and declined to appeal the Court's decision and settled the litigation, sponsors of the ballot measure have appealed.

Regulation of Health, Safety and Environmental Matters

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

- establish air, soil and water quality standards for a given region, such as the San Joaquin Valley, conduct regional, community or field monitoring of air, soil or water quality, and require attainment plans to meet those regional standards, which may include significant mitigation measures or restrictions on development, economic activity and transportation in such region;
- require various permits, approvals and mitigation measures before drilling, workover, production, underground fluid injection or waste disposal commences, or before facilities are constructed or put into operation;
- require the installation of sophisticated safety and pollution control equipment, such as leak detection, monitoring and shutdown systems, and implementation of inspection, monitoring and repair programs 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, impose energy efficiency or renewable energy standards on us or users of our products and services, and restrict the use of oil, natural gas or certain petroleum–based products such as fuels and plastics;
- restrict the types, quantities and concentrations of regulated materials, including oil, natural gas, produced water or wastes, that can be released or discharged into the environment, or any other uses of those materials resulting from drilling, production, processing, power generation, transportation or storage activities;
- limit or prohibit operations on lands lying within coastal, wilderness, wetlands, groundwater recharge, endangered species habitat and other protected areas, and require the dedication of surface acreage for habitat conservation;
- establish standards for the management of solid and hazardous wastes or the closure, abandonment, cleanup or restoration of former operations, such as plugging and abandonment of wells and decommissioning of facilities;
- impose substantial liabilities for unauthorized releases or discharges of regulated materials into the environment with respect to our current or former properties and operations and other locations where such materials generated by us or our predecessors were released or discharged;
- require comprehensive environmental analyses, recordkeeping and reports with respect to operations affecting federal, state and private lands or leases;
- impose taxes or fees with respect to the foregoing matters;
- may expose us to litigation with government authorities, counterparties, special interest groups or others; and
- may restrict our rate of oil, NGLs, natural gas and electricity production.

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

In 2014, at the request of the EPA, CalGEM commenced a detailed review of the multi-decade practice of permitting underground injection wells and associated aquifer exemptions under the Safe Drinking Water Act (SDWA). In 2015, the state set deadlines to obtain the EPA's confirmation of aquifer exemptions under the SDWA in certain formations in certain fields. Since the state and the EPA did not complete their review before the state's deadlines, the state announced that it will not rescind permits or enforce the deadlines with respect to many of the formations pending completion of the review but has applied the deadlines to others. Several industry groups and operators challenged CalGEM's implementation of its aquifer exemption regulations. In March 2017, the Kern County Superior Court issued an injunction barring the blanket enforcement of CalGEM's aquifer exemption regulations. The court found that CalGEM must find actual harm results from an injection well's operations and go through a hearing process before the agency can issue fines or shut down operations. During the review, the state has restricted injection in certain formations or wells in several fields, including some operated by us, requested that we change injection zones in certain fields, and held certain pending injection permits in abeyance. We are coordinating with the state to change injection zones in certain fields to facilitate disposal of produced water in deeper formations where feasible or to increase recycling of produced water in pressure maintenance or waterfloods in lieu of disposal. As previously noted, the State Department of Finance is conducting a performance audit of CalGEM's permitting process for injection projects, with an independent review of the technical content of pending injection PALs by Lawrence Livermore National Laboratory.

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

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

Regulation of Climate Change and Greenhouse Gas (GHG) Emissions

A number of international, federal, state, regional and local efforts seek to prevent or mitigate the effects of climate change or to track, mitigate and reduce GHG emissions associated with energy use and industrial activity, including operations of the oil and natural gas production sector and those who use our products as a source of energy or feedstocks. In November 2019, the U.S. formally announced its withdrawal from the 2015 Paris Agreement on climate change, effective in November 2020. Notwithstanding this action, the EPA has adopted federal regulations to:

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

California has adopted the most stringent laws and regulations to reduce GHG emissions. These state laws and regulations:

- established a “cap-and-trade” program for GHG emissions that sets a statewide maximum limit on covered GHG emissions, and this cap declines annually to reach 40% below 1990 levels by 2030, the year that the cap-and-trade program currently expires;
- require allowances or qualifying offsets for GHGs emitted from California operations and for the volume of natural gas, propane and liquid transportation fuels sold for use in California;
- established a low carbon fuel standard (LCFS) and associated tradable credits that require a progressively lower carbon intensity of the state's fuel supply than baseline gasoline and diesel fuels, and provide a mechanism to generate LCFS credits through innovative crude oil production methods such as those employing solar or wind energy or carbon capture and sequestration;

- mandated that California derive 60% of its electricity for retail customers from renewable resources by 2030;
- established a policy to derive all of California's retail electricity from renewable or "zero-carbon" resources by 2045, subject to required evaluation of the feasibility by state agencies;
- imposed state goals to double the energy efficiency of buildings by 2030 and to reduce emissions of methane and fluorocarbon gases by 40% and black carbon by 50% below 2013 levels by 2030; and
- mandated that all new single family and low–rise multifamily housing construction in California include rooftop solar systems or direct connection to a state–approved community solar system.

The EPA and the California Air Resources Board (CARB) have also expanded direct regulation of methane as a contributor to GHG emissions. In 2016, the EPA adopted regulations to require additional emission controls for methane, volatile organic compounds and certain other substances for new or modified oil and natural gas facilities. Although the EPA increased the flexibility of certain of its federal methane regulations in 2019, CARB has implemented more stringent regulations that require monitoring, leak detection, repair and reporting of methane emissions from both existing and new oil and natural gas production, pipeline gathering and boosting facilities and natural gas processing plants, as well as additional controls such as tank vapor recovery to capture methane emissions.

Regulation of Transportation, Marketing and Sale of Our Products

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

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

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

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

International treaties and regulations also affect the marketing or sale of our products. For example, on January 1, 2020, the International Maritime Organization reduced the maximum sulfur content in marine fuels from 3.5% to 0.5% by weight under the International Convention for the Prevention of Pollution from Ships. Under this IMO 2020 rule, ships must either switch to low-sulfur fuels or install scrubbing facilities for emission controls, which may affect the price of and demand for varying grades of crude oil, both internationally and in California.

In addition, mandates or subsidies have been adopted or proposed by the state and certain local governments to require or promote renewable energy or electrification of transportation, appliances and equipment, or prohibit or restrict the use of petroleum products, by our customers or the public. For example, in January 2020, the California Public Utilities Commission (CPUC) commenced a rulemaking to develop a long-term natural gas planning strategy to ensure safe and reliable gas systems at just and reasonable rates during what it describes as a 25-year transition from natural gas-fueled technologies to meet the state's GHG goals. In addition, several municipalities in California enacted ordinances in 2019 that restrict the installation of natural gas appliances and infrastructure in new residential or commercial construction, which could affect the retail natural gas market of our utility customers and the demand and prices we receive for the natural gas we produce. Several of these ordinances face legal challenges.

Available Information

We make available free of charge on our website, www.crc.com, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, our annual proxy statements and amendments to those reports filed or furnished, if any, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Our website contains additional important information such as our Sustainability Report and descriptions of our health, safety, environmental and community outreach programs, as well as reconciliations of non-GAAP financial measures and additional information on performance measures. Unless otherwise provided herein, information contained on our website is not part of this report. The SEC maintains an internet site, http://www.sec.gov, that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

ITEM 1A RISK FACTORS

Described below are certain risks and uncertainties that could adversely affect our business, financial condition, results of operations or cash flow. These risks are not the only risks we face. Our business could also be affected materially and adversely by other risks and uncertainties that are not currently known to us or that we currently deem to be immaterial.

Prices for our products can fluctuate widely and an extended period of low prices could adversely affect our financial condition, results of operations, cash flow and ability to invest in our assets.

Our financial condition, results of operations, cash flow and ability to invest in our assets are highly dependent on oil, natural gas and NGL prices. A sustained period of low prices for oil, natural gas and NGLs would reduce our cash flows from operations and could reduce our borrowing capacity or cause a default under our financing agreements. Under these conditions, if we were unable to improve liquidity through additional financing, asset monetizations, restructuring of our debt obligations, equity issuances or otherwise, cash flow from operations and expected available credit capacity could be insufficient to meet our commitments. Successfully completing these actions could have significant adverse effects such as higher operating and financing costs, dilution of equity and further covenant restrictions. Past refinancing activities have resulted in increases in our annual interest expense and future refinancing activities may have the same or greater effect.

Historically, the markets for oil, natural gas and NGLs have been volatile and they are likely to continue to be so. We are particularly dependent on Brent crude prices that have been as low as $27.88 per barrel and as high as $115.19 per barrel during the period between 2014 and 2019. Factors affecting these commodity prices include:

- changes in domestic and global supply and demand;
- domestic and global inventory levels;
- political and economic conditions;
- the actions of OPEC and other significant producers and governments;
- changes or disruptions in actual or anticipated production, refining and processing;
- worldwide drilling and exploration activities;
- government energy policies and regulation, including with respect to climate change;
- the effects of conservation;
- weather conditions and other seasonal impacts;
- speculative trading in derivative contracts;
- currency exchange rates;
- technological advances;
- transportation and storage capacity, bottlenecks and costs in producing areas;
- the price, availability and acceptance of alternative energy sources;
- regional market conditions; and
- other matters affecting the supply and demand dynamics for these products.

Lower prices could have adverse effects on our business, financial condition, results of operations and cash flow, including:

- reducing our proved oil and natural gas reserves over time, including as a result of impairments of existing reserves;
- limiting our ability to grow or maintain future production including a delay in the reversion dates of certain of our JVs;
- causing a reduction in our borrowing base under our 2014 Revolving Credit Facility, which could affect our liquidity;
- reducing our ability to make interest payments or maintain compliance with financial covenants in the agreements governing our indebtedness, which could trigger mandatory loan repayments and default and foreclosure by our lenders and bondholders against our assets;
- forcing monetization events of certain assets under one of our JV arrangements;
- affecting our ability to attract counterparties and enter into commercial transactions, including hedging, surety or insurance transactions; and
- limiting our access to funds through the capital markets and the price we could obtain for asset sales or other monetization transactions of our equity and debt securities.

Our hedging program does not provide downside protection for all of our production in 2020 and beyond. As a result, our hedges do not fully protect us from commodity price declines, and we may be unable to enter into acceptable additional hedges in the future.

Our lenders could limit our borrowing capabilities and restrict our ability to use or access capital.

Our 2014 Revolving Credit Facility is an important source of our liquidity. Our ability to borrow under our 2014 Revolving Credit Facility is limited by our borrowing base, the size of our lenders' commitments and our ability to comply with covenants, including a minimum month-end liquidity requirement of $150 million. As of December 31, 2019, we had approximately $317 million of available borrowing capacity, before taking into account the minimum month-end liquidity requirement.

The borrowing base under our 2014 Revolving Credit Facility is redetermined semi-annually on May 1 and November 1. Our lenders determine our borrowing base by reference to the value of our reserves and other factors that the administrative agent may deem appropriate in good faith in accordance with its usual and customary oil and gas lending criteria as they exist at the particular time. The lenders under our 2014 Revolving Credit Facility may also factor other liabilities, including our other indebtedness, into the determination of our borrowing base. Currently, our borrowing base is set at $2.3 billion and the lenders' aggregate commitment under our 2014 Revolving Credit Facility is $1 billion. However, the $1.3 billion outstanding under our 2017 Credit Agreement is taken into account in limiting the amount of such commitment. Thus, any reduction in our borrowing base would have the effect of reducing capacity under the 2014 Revolving Credit Facility. Any such reduction requires the consent and approval of the lenders holding 66 $^{2}/_{3}$% of the commitments under the 2014 Revolving Credit Facility.

We have informed the Administrative Agent under our 2014 Revolving Credit Facility of the proposed exchange offers described in our Form 8-K filed on February 21, 2020 and discussions are ongoing. Initially, the Administrative Agent expressed its own view that consummation of the exchange transactions may present material concerns to our first lien lenders, including lenders under the 2014 Revolving Credit Facility who could seek a significant reduction in our borrowing base on or before our next scheduled borrowing base redetermination. We have not received similar communications from other large lenders in our 2014 Revolving Credit Facility, some of which are dealer managers in the proposed exchange offers. Our more recent discussions with the Administrative Agent have focused on our need to address the debt maturities in 2021 and 2022, the subsequent steps that we plan to take to address refinancing these debt maturities and that the transactions described herein are a first step toward that objective. The Administrative Agent has indicated that if we address these maturities before the next redetermination date, a more muted response from the first lien lenders may be possible. The Administrative Agent did note, however, that many considerations will go into the ultimate decision by the lenders under the 2014 Revolving Credit Facility and the weight of those considerations may vary given conditions of both the lending market and the general upstream industry at the time.

We cannot assure you that the lenders under the 2014 Revolving Credit Facility will not reduce our borrowing base by a material amount as a result of the proposed exchange offers or otherwise. Any reduction in our $2.3 billion borrowing base would only have the effect of reducing the commitment under the 2014 Revolving Credit Facility by up to $100 million unless the borrowing base reduction exceeded $1.4 billion, at which point the reduction and loss of availability would be dollar for dollar. Any reduction in our borrowing base could materially and adversely affect our liquidity and may hinder our ability to execute on our development plan. We would seek to reduce our capital program and expenses and potentially monetize assets among other things to address tighter liquidity constraints. However, there can be no assurances that such actions will be possible or adequate to address such a reduction in our borrowing base. If the reduction in our borrowing base were sufficiently severe that we were unable to maintain adequate liquidity to conduct operations and meet our obligations, we could ultimately be forced to seek bankruptcy protection.

The financial covenants that we must satisfy under our 2014 Revolving Credit Facility include a month-end minimum liquidity test, certain financial ratios that measure our leverage and fixed interest charges on a quarterly basis, and the present value of our reserves on a semi-annual basis. These covenants could limit our ability to borrow under our 2014 Revolving Credit Facility or obtain additional financing through the capital markets or otherwise. Certain other agreements governing our long-term indebtedness also include financial ratios that are generally less restrictive than our 2014 Revolving Credit Facility.

If we were to breach any of the covenants under our 2014 Revolving Credit Facility or any of our other credit agreements or indentures, the lenders under our 2014 Revolving Credit Facility would be permitted to cease lending under the facility, accelerate the repayment of the outstanding amounts due and foreclose against the assets securing them.

For a further description of our 2014 Revolving Credit Facility and our other credit agreements, see *Part II*, *Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources – Credit Agreements*.

We have significant indebtedness that could limit our financial and operating flexibility and make us more vulnerable in economic downturns.

As of December 31, 2019, the face value of our outstanding long-term consolidated indebtedness was $4.98 billion. Our financing agreements permit us to incur significant additional indebtedness as well as certain other obligations. In addition, we may seek amendments or waivers from our existing lenders and bondholders to the extent we need to incur indebtedness above amounts currently permitted by our financing agreements.

Our level of indebtedness may have adverse effects on our business, financial condition, cash flows or results of operations, including:

- jeopardizing our ability to execute our business plans;
- increasing our vulnerability to adverse changes in economic and industry conditions related to our business;
- putting us at a disadvantage against competitors that have lower fixed obligations and more cash flow to devote to their businesses;
- limiting our ability to obtain favorable financing for working capital, capital investments and general corporate and other purposes;
- limiting our ability to enter into hedging contracts;
- limiting our ability to fund capital investments, react to competitive pressures and engage in certain transactions that might otherwise be beneficial to us;
- defaulting on a commercial agreement with one of our JVs; and
- failing to redeem the interests held by one of our JV partners.

Our financing agreements also include covenants that restrict management's discretion to operate our business in certain circumstances. These restrictions include limitations that could affect our ability to:

- incur additional indebtedness and grant additional liens;
- repay junior indebtedness, including our Second Lien Notes and Senior Notes;
- make investments;
- enter into JVs;
- pay dividends and make other restricted payments;
- sell assets;
- use the proceeds of asset sales for certain purposes;
- enter into mergers or acquisitions; and
- release collateral.

These limitations are further described in *Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Credit Agreements* and the documents governing our indebtedness that are filed with the SEC.

Our financing agreements, including the 2014 Revolving Credit Facility, contain customary cross-default mechanisms that provide that an event of default under any one of those agreements may trigger an event of default under all of those agreements. In such an event, we might not be able to obtain alternative financing or, if we are able to obtain such financing, we might not be able to obtain it on terms acceptable to us, which would negatively affect our ability to implement our business plan, make capital expenditures or finance our operations.

A significant portion of our outstanding indebtedness bears interest at variable rates. Although we have purchased derivative contracts that limit our interest rate exposure for a portion of this indebtedness, a rise in interest rates will increase our interest expense to the extent we do not have interest-rate hedges and could limit our liquidity and our ability to comply with our debt covenants.

Our ability to meet our debt obligations and other financial needs will depend on our future performance, which is influenced by market, financial, business, economic, regulatory and other factors. If our cash flow is not sufficient, we may be required to refinance debt, sell assets or issue additional equity on terms that may be unattractive, if these can be done at all. Failure to make a scheduled payment or to comply with covenants relating to our indebtedness could result in a default. In addition, any perceived or actual deterioration in our liquidity or credit position could cause our counterparties to require new letters of credit or to increase the amounts covered by existing letters of credit. Any of these factors could result in a material adverse effect on our business, financial condition, cash flows or results of operations and a default on our indebtedness could result in acceleration of all of our debt and foreclosure against assets constituting collateral for our indebtedness.

A significant portion of our long-term indebtedness will mature within two years and will likely need to be refinanced. There can be no assurances we will be able to refinance this indebtedness on acceptable terms or at all.

Approximately $2 billion of our long-term indebtedness will mature in 2021, including amounts outstanding under our 2014 Revolving Credit Facility and 2016 Credit Agreement. An additional $1 billion under our 2017 Credit Agreement will mature in October 2021 if more than $100 million is outstanding under our 2016 Credit Agreement at that time. Finally, our Second Lien indenture will require us to make a principal repayment of $287 million in June 2021. Our ability to satisfy these maturities and obligations will likely require us to refinance a large portion of this indebtedness. Our ability to refinance indebtedness will depend on the condition of the capital markets and credit markets and our financial condition and credit rating. The terms of existing debt instruments may restrict us from pursuing certain refinancing strategies as well as other strategies to reduce indebtedness. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. There can be no assurances we will be able to refinance this indebtedness on acceptable terms or at all, and if we are unable to do so we may not be able to satisfy these maturities and obligations as they become due.

Our stock price and trading volume may be volatile, which could result in losses for our stockholders.

The public market for our common stock has been characterized by significant price and volume fluctuations. Our stock price and volume may be affected by our operating results in any period which fail to meet the investment community’s expectations and our stock price has experienced extreme volatility that has often been unrelated to our operating performance. There can be no assurance that the market price of our common stock will not decline below its current or historic price ranges. These highly volatile market conditions, particularly in the oil and natural gas sector, could result in a stockholder losing a substantial part or all of its investment in our common stock. In the past, following periods of volatility in the market price of a company’s securities, securities litigation has been initiated. Should litigation be initiated against us, whether or not successful, it could result in substantial costs and diversion of our management’s attention, both of which could harm our business and financial condition.

Our business requires substantial capital investments, which may include acquisitions or JVs. We may be unable to fund these investments which could lead to a decline in our oil and natural gas reserves or production. Our capital investment program is also susceptible to risks that could materially affect its implementation.

Our exploration, development and acquisition activities require substantial capital investments. Historically, we have funded our capital investments through a combination of cash flow from operations, borrowings under our 2014 Revolving Credit Facility and joint ventures. We seek to manage our internally funded capital investments to closely align with projected cash flow from operations. Accordingly, a reduction in projected operating cash flow could cause us to reduce our future capital investments. In general, the ability to execute our capital plan depends on a number of factors, including:

- the amount of oil, natural gas and NGLs we are able to produce;
- commodity prices;
- regulatory and third-party approvals;
- our ability to timely drill, complete and stimulate wells;
- our ability to secure equipment, services and personnel; and
- the availability of external sources of financing.

Access to future capital may be limited by our lenders, our JV partners, capital markets constraints, activist funds or investors, or poor stock price performance. Because of these and other potential variables, we may be unable to deploy capital in the manner planned, which may negatively impact our production levels and development activities and limit our ability to make acquisitions or enter into JVs.

Unless we make sufficient capital investments and conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our ability to make the necessary long-term capital investments or acquisitions needed to maintain or expand our reserves may be impaired to the extent we have insufficient cash flow from operations or liquidity to fund those activities. Over the long term, a continuing decline in our production and reserves would reduce our liquidity and ability to satisfy our debt obligations by reducing our cash flow from operations and the value of our assets.

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

Many uncertainties exist in estimating quantities of proved reserves and related future net cash flows. Our estimates are based on various assumptions that require significant judgment in the evaluation of available information. Our assumptions may ultimately prove to be inaccurate. Additionally, reservoir data may change over time as more information becomes available from development and appraisal activities.

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.

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

In addition, our reserves information represents estimates prepared by internal engineers. Although 80% of our 2019 proved reserve estimates were audited by our independent petroleum engineers, Ryder Scott Company, L.P. and Netherland, Sewell & Associates, Inc., we cannot guarantee that the estimates are accurate. Reserves estimation is a partially subjective process of estimating accumulations of oil and natural gas. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows from those reserves depend upon a number of variables and assumptions, including:

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

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

Acquisition and disposition activities and our JVs involve substantial risks.

Our acquisition activities carry risks that we may:

- not fully realize anticipated benefits due to less-than-expected reserves or production or changed circumstances;
- bear unexpected integration costs or experience other integration difficulties;
- experience share price declines based on the market’s evaluation of the activity;
- assume liabilities that are greater than anticipated; and
- be exposed to currency, political, marketing, labor and other risks, particularly associated with investments in foreign assets.

In connection with our acquisitions, we are often only able to perform limited due diligence. Successful acquisitions of oil and natural 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.

If we are not able to make acquisitions, we may not be able to grow our reserves or develop our properties in a timely manner or at all.

Part of our business strategy involves entering into JVs and divesting non-core assets. Our JVs and disposition activities carry risks that we may:

- not be able to realize reasonable prices or rates of return for assets;
- be required to retain liabilities that are greater than desired or anticipated;
- experience increased operating costs; and
- reduce our cash flows if we cannot replace associated revenue.

There can be no assurance that we will be able to successfully enter into new JVs or that JVs will occur in the time frames or with economic terms that we expect. We may also be unable to divest assets on financially attractive terms or at all. Our ability to enter into JVs and sell assets is also limited by the agreements governing our indebtedness.

If we are not able to sell assets as needed or enter into JVs, we may not be able to generate proceeds to support our liquidity and capital investments.

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

Our operations are subject to complex and stringent federal, state, local and other laws and regulations relating to the exploration and development of our properties, as well as the production, transportation, marketing and sale of our products. Federal, state and local agencies may assert overlapping authority to regulate these areas. For example, the jurisdiction, duties and enforcement authority of various state agencies have significantly increased with respect to oil and natural gas activities in recent years, and these state agencies as well as certain cities and counties have significantly revised their regulations, regulatory interpretations and data collection and reporting requirements and plan to issue additional regulations of certain oil and natural gas activities in 2020. In addition, certain of these federal, state and local laws and regulations may apply retroactively and may impose strict or joint and several liability on us for events or conditions over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

See *Items 1 and 2 – Business and Properties – Regulation of the Oil and Natural Gas Industry* for a description of laws and regulations that affect our business. To operate in compliance with these laws and regulations, we must obtain and maintain permits, approvals and certificates from federal, state and local government authorities for a variety of activities including siting, drilling, completion, stimulation, operation, inspection, maintenance, transportation, storage, marketing, site remediation, decommissioning, abandonment, fluid injection and disposal and water recycling and reuse. Failure to comply may result in the assessment of administrative, civil and/or criminal fines and penalties and liability for noncompliance, costs of corrective action, cleanup or restoration, compensation for personal injury, property damage or other losses, and the imposition of injunctive or declaratory relief restricting or prohibiting certain operations. Under certain environmental laws and regulations, we could be subject to strict or joint and several liability for the removal or remediation of contamination, including on properties over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

Our customers, including refineries and utilities, and the businesses that transport our products to customers, are also highly regulated. For example, various government authorities have sought to restrict the use of oil, natural gas or certain petroleum–based products such as fuels and plastics. Federal and state pipeline safety agencies have adopted or proposed regulations to expand their jurisdiction to include more gas and liquid gathering lines and pipelines and to impose additional mechanical integrity, leak detection and reporting requirements. The state has adopted additional regulations on the storage of natural gas that could affect the demand for or availability of such storage, increase seasonal volatility, or otherwise affect the prices we receive from customers. The CPUC has commenced a rulemaking to develop a long-term natural gas planning strategy to ensure safe and reliable gas systems at just and reasonable rates during what it describes as a 25-year transition from natural gas-fueled technologies to meet the state's GHG goals. Certain municipalities have enacted restrictions on the installation of natural gas appliances and infrastructure in new residential or commercial construction, which could affect the retail natural gas market for our utility customers and the demand and prices we receive for the natural gas we produce.

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

Government authorities and other organizations continue to study health, safety and environmental aspects of oil and natural gas operations, including those related to air, soil and water quality, ground movement or seismicity and natural resources. For example, the Legislature expanded CalGEM's duties in 2019 to include public health and safety and CalGEM is commencing public health and safety workshops in the first quarter of 2020 to be followed by an associated rulemaking process. Government authorities have also adopted or proposed new or more stringent requirements for permitting, inspection and maintenance of wells, pipelines and other facilities, and public disclosure or environmental review of, or restrictions on, oil and natural gas operations, including proposed setback distances from other land uses. Such requirements or associated litigation could result in potentially significant added costs to comply, delay or curtail our exploration, development, fluid injection and disposal or production activities, preclude us from drilling, completing or stimulating wells, or otherwise restrict our ability to access and develop mineral rights, any of which could have an adverse effect on our expected production, other operations and financial condition.

Changes to elected or appointed officials or their priorities and policies could result in different approaches to the regulation of the oil and natural gas industry. We cannot predict the actions the Governor or Legislature may take with respect to the regulation of our business, the oil and natural gas industry or the state's economic, fiscal or environmental policies.

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

The exploration and development of oil and natural gas properties depend in part on our analysis of geophysical, geologic, engineering, production and other technical data and processes, including the interpretation of 3D seismic data. This analysis is often inconclusive or subject to varying interpretations. We also bear the risks of equipment failures, accidents, environmental hazards, unusual geological formations or unexpected pressure or irregularities within formations, adverse weather conditions, permitting or construction delays, title disputes, surface access disputes, disappointing drilling results or reservoir performance (including lack of production response to workovers or improved and enhanced recovery efforts) and other associated risks.

We allocate capital by reference to a VCI metric. We calculate the VCI of a well or project at the time capital is allocated and frequently re-calculate the VCI after a well or project is completed. VCI is calculated based on internal estimates of future cash flows and capital investment, which are inherently uncertain. In addition, future cash flows are dependent on our production costs. Our production cost per barrel is higher than that of many of our peers due to the extraction methods we use, the large number of wells we operate and the effects of our PSC-type contracts.

Our decisions and ultimate profitability are also affected by commodity prices, the availability of capital, regulatory approvals, available transportation and storage capacity, the political environment and other factors. Our cost of drilling, completing, stimulating, equipping, operating, inspecting, maintaining and abandoning wells is also often uncertain.

Any of the forgoing operational or financial risks could cause actual results to differ materially from the expected VCI or cause a well or project to become uneconomic or less profitable than forecast.

We have specifically identified locations for drilling over the next several years, which represent a significant part of our long-term growth strategy. Our actual drilling activities may materially differ from those presently identified. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling or development of these projects. We make assumptions about the consistency and accuracy of data when we identify these locations that may prove inaccurate. We cannot guarantee that our identified drilling locations will ever be drilled or if we will be able to produce crude oil or natural gas from these drilling locations. In addition, some of our leases could expire if we do not establish production in the leased acreage. The combined net acreage covered by leases expiring in the next three years represented approximately 15% of our total net undeveloped acreage at December 31, 2019.

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

The risk profile for our exploration drilling locations is higher than for other locations because we have less geologic and production data and drilling history, in particular for those exploration drilling locations in unconventional reservoirs, which are in unproven geologic plays. 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. We may not find commercial amounts of oil or natural gas or the costs of drilling, completing, stimulating and operating wells in these locations may be higher than initially expected. 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. In either 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 the timing, cost and our ability to develop this asset.

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

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

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), enacted in 2010, established federal oversight and regulation of the over-the-counter (OTC) derivatives market and entities, like us, that participate in that market. Among other things, the Dodd-Frank Act required the U.S. Commodity Futures Trading Commission to promulgate a range of rules and regulations applicable to OTC derivatives transactions. These regulations 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, the effects of these regulations could reduce our hedging opportunities which could adversely affect our revenues and cash flow during periods of low commodity prices.

Recently, proposals have been made by U.S. regulators which would implement a new approach for calculating the exposure of derivative contracts under the applicable agencies' regulatory capital rules, referred to as the standardized approach for counterparty credit risk or SA-CCR. If adopted as proposed, certain financial institutions would be required to comply with the new SA-CCR rules beginning on July 1, 2020 and the rules could significantly increase the capital requirements for certain participants in the OTC derivatives market in which we participate. These increased capital requirements could result in significant additional costs being passed through to end users like us or reduce the number of participants or products available to us in the OTC derivatives market. The effects of these regulations could reduce our hedging opportunities or substantially increase the cost of hedging, which could adversely affect our revenues and cash flow.

The European Union and other non-U.S. jurisdictions may implement 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, which could also adversely affect our hedging opportunities.

Adverse tax law changes may affect our operations.

We are subject to taxation by various tax authorities at the federal, state and local levels where we do business. New legislation could be enacted by any of these government authorities that could adversely affect our business. In California, there have been numerous state and local proposals for additional income, sales, excise and property taxes, including additional taxes on oil and natural gas production. Although such proposals targeting our industry have not become law, campaigns by various interest groups could lead to additional future taxes.

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 concentrated in California. Because of this geographic concentration, the success and profitability of our operations may be disproportionately exposed to the effect of regional conditions. These include local price fluctuations, changes in state or regional laws and regulations affecting our operations and other regional supply and demand factors, including gathering, pipeline, transportation and storage capacity constraints, limited potential customers, infrastructure capacity and availability of rigs, equipment, oil field services, supplies and labor. Our operations are also exposed to natural disasters and related events common to California, such as wildfires, mudslides, high winds and earthquakes. Further, our operations may be exposed to power outages, 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.

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

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions, and regulation of GHGs and other air quality issues, may materially affect our business in many ways, including increasing the costs to provide our products and services and reducing demand for, and consumption of, our products and services, and we may be unable to recover or pass through a significant portion of our costs. In addition, legislative and regulatory responses to such issues at the federal, state and local level may increase our capital and operating costs and render certain wells or projects uneconomic, and potentially lower the value of our reserves and other assets. Both the EPA and California have implemented laws, regulations and policies that seek to reduce GHG emissions as discussed in *Part I, Items 1 and 2 – Business and Properties – Regulation of the Oil and Natural Gas Industry*. California's cap-and-trade program operates under a market system and the costs of such allowances per metric ton of GHG emissions are expected to increase in the future as CARB tightens program requirements and annually increases the minimum state auction price of allowances and reduces the state's GHG emissions cap. As the foregoing requirements become more stringent, we may be unable to implement them in a cost-effective manner, or at all.

Concern over climate change and GHG and other emissions has also resulted in increasing political risks in California and the United States, including climate change related pledges made by various candidates for federal, state and local offices in California and certain candidates seeking the office of the President of the United States in 2020. These include threats to ban hydraulic fracturing and other stimulation of oil and natural gas wells and permitting of various operations, pipeline infrastructure and other oil and gas facilities on government or private lands, which could negatively impact our operations and properties. Other actions that could be pursued by presidential candidates may include the reversal of the United States' withdrawal from the Paris Agreement in November 2020, as well as reversing various regulatory changes made or proposed by the Trump Administration to promote energy production and other development. Additionally, various claimants, including certain municipalities, have filed litigation alleging that energy producers are liable for damages attributed to climate change.

In addition, other current and proposed international agreements and federal, state and local laws, regulations and policies seek to restrict or reduce the use of petroleum products in transportation fuels, electricity generation, plastics and other applications, prohibit future sale or use of vehicles, appliances or equipment that require petroleum fuels, impose additional taxes and costs on producers and consumers of petroleum products and require or subsidize the use of renewable energy. The state has set an ambitious goal by executive order to be "carbon-neutral" by 2045 and initiated and funded studies to identify strategies to implement this goal. The Legislature, state agencies and various municipalities have adopted or proposed laws, regulations and policies that seek to significantly reduce emissions from vehicles, increase the use of "zero emission" vehicles, reduce the use of plastics, increase renewable energy mandates for utilities and in residential and commercial construction, and replace natural gas appliances and infrastructure in residential and commercial buildings with electric appliances.

Government authorities can impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations, and various state and local agencies are conducting increased regional, community and field air monitoring specifically with respect to oil and natural gas operations. In addition, California air quality laws and regulations, particularly in Southern and Central California where most of our operations are located, are in most instances more stringent than analogous federal laws and regulations. For example, the San Joaquin Valley will be required to adopt more rigorous attainment plans under the Clean Air Act to comply with federal ozone and particulate matter standards, and these efforts could affect our activities in the region and our ability and cost to obtain permits for new or modified operations.

To the extent financial markets view climate change and GHG or other emissions as an increasing financial risk, this could adversely impact our cost of, and access to, capital and the value of our stock and our assets. Shareholders currently invested in oil and gas companies may elect in the future to shift some or all of their investments into other sectors, and institutional lenders may elect not to provide funding for oil and gas companies. Additionally, environmental activists, proponents of the Paris Agreement, and other governmental and non-governmental organizations concerned about climate change have sought to pressure public and private investment funds not to invest in oil and gas companies and institutional lenders to restrict oil and gas companies' access to capital. Limitation of investments in and financings for oil and gas companies like us could result in the restriction, delay or cancellation of drilling programs or development or production activities.

We believe, but cannot guarantee, that our local production of oil, NGLs and natural gas will remain essential to meeting California's energy and feedstock needs for the foreseeable future. We have also established 2030 Sustainability Goals for water recycling, renewables integration, methane emission reduction and carbon capture and sequestration in our life-of-field planning that align with the state's long-term goals and support our ability to continue to efficiently implement federal, state and local laws, regulations and policies, including those relating to air quality and climate, in the future. However, there can be no assurances that we will be able to design, permit, fund and implement such projects in a timely and cost-effective manner or at all, or that we, our customers or end users of our products will be able to satisfy long-term environmental, air quality or climate goals if those are applied as enforceable mandates.

The adoption and implementation of new or more stringent international, federal, state or local legislation, regulations or policies that impose more stringent standards for GHG or other emissions from our operations or otherwise restrict the areas in which we may produce oil, natural gas, NGLs or electricity or generate GHG or other emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for or value of our products and services. Additionally, political, litigation and financial risks may result in restricting or canceling oil and natural gas production activities, incurring liability for infrastructure damages or other losses as a result of climate change, or impairing our ability to continue to operate in an economic manner. Moreover, climate change may pose increasing risks of physical impacts to our operations and those of our suppliers, transporters and customers through damage to infrastructure and resources resulting from drought, wildfires, sea level changes, flooding and other natural disasters and other physical disruptions. One or more of these developments could have a material adverse effect on our business, financial condition and results of operations.

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

We are not fully insured against all risks. Our oil and natural gas exploration and production activities and our assets are subject to risks such as fires, explosions, releases, discharges, power outages, equipment or information technology failures and industrial accidents, as are the assets and properties of third parties who supply us with energy, equipment and services or who purchase, transport or use our products. In addition, events such as earthquakes, floods, mudslides, wildfires, power outages, high winds, droughts, cyber-security, vandalism or terrorist attacks and other events may cause operations to cease or be curtailed and could adversely affect our business, workforce and the communities in which we operate. Further, recent wildfires experienced in California have limited the availability and increased the cost of obtaining insurance against certain natural disasters. We may be unable to obtain, or may elect not to obtain, insurance for certain risks if we believe that the cost of available insurance is excessive relative to the risks presented.

Information technology failures and cyber-security attacks could adversely affect us.

We rely on electronic systems and networks to communicate, control and manage our exploration, development and production activities. We also use these systems and networks to prepare our financial management and reporting information, to analyze and store data and to communicate internally and with third parties, including our service providers and customers. If we record inaccurate data or experience infrastructure outages, our ability to communicate and control and manage our business could be adversely affected.

Cyber-security attacks on businesses have escalated and become more sophisticated in recent years and include attempts to gain unauthorized access to data, malicious software, ransomware and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential information or the corruption of data. In addition, our vendors, customers and other business partners may separately suffer disruptions or breaches from cyber-security attacks that, in turn, could adversely impact our operations and compromise our information. If we or the third parties with whom we interact were to experience a successful attack, the potential consequences to our business, workforce and the communities in which we operate could be significant, including financial losses, loss of business, litigation risks and damage to reputation. As the sophistication of cyber-security attacks continues to evolve, we may be required to expend additional resources to further enhance our security.

ITEM 1B UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 3 LEGAL PROCEEDINGS

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

ITEM 4 MINE SAFETY DISCLOSURES

Not applicable.

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 is listed under the symbol "CRC" on the New York Stock Exchange.

Holders of Record

Our common stock was held by approximately 20,160 stockholders of record at December 31, 2019.

Dividend Policy

We currently do not pay, and do not anticipate paying, dividends on our common stock in the foreseeable future. In addition, covenants under our 2014 Revolving Credit Facility generally restrict the payment of cash dividends on our stock, subject to certain exceptions.

Securities Authorized for Issuance Under Equity Compensation Plans

We currently maintain two equity compensation plans that were approved by our shareholders. The aggregate number of shares of our common stock authorized for issuance under these stock-based compensation plans for our executives, employees and non-employee directors is 8.8 million, of which approximately 5.8 million had been issued or reserved through December 31, 2019.

A warrant for 1,250,000 shares was issued in July 2019 with a $40.00 exercise price in connection with one of our development joint ventures, the Alpine JV. The holder of the warrant will be entitled to exercise the warrant in tranches as funding milestones are achieved. Each tranche has a five-year term commencing on the date on which such tranche becomes exercisable. As of December 31, 2019, 200,000 shares of our common stock were exercisable under this warrant. For more on the Alpine JV transaction, see *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operation, Joint Ventures*.

The following is a summary of the securities available for issuance as of December 31, 2019:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights		Weighted-average exercise price of outstanding options, warrants and rights		Number of securities remaining available for future issuance under equity compensation plans (excluding securities in column (a))	
	(a)		(b)		(c)	
Equity compensation plans approved by security holders	2,477,714	(1)	$59.00	(2)	3,012,096	(3)
Equity compensation plan not approved by security holders[4]	1,250,000		$40.00		—	
Total	3,727,714				3,012,096	

(1) We net settle shares issued upon exercise of options granted under our equity compensation plan. As a result, the number of shares actually issued, if any, will be less than the amount shown. A description of our stock-based compensation plans approved by security holders can be found in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 11 Stock-Based Compensation*.

(2) Exercise price applies only to approximately 1.4 million options included in column (a) and not to any other awards.

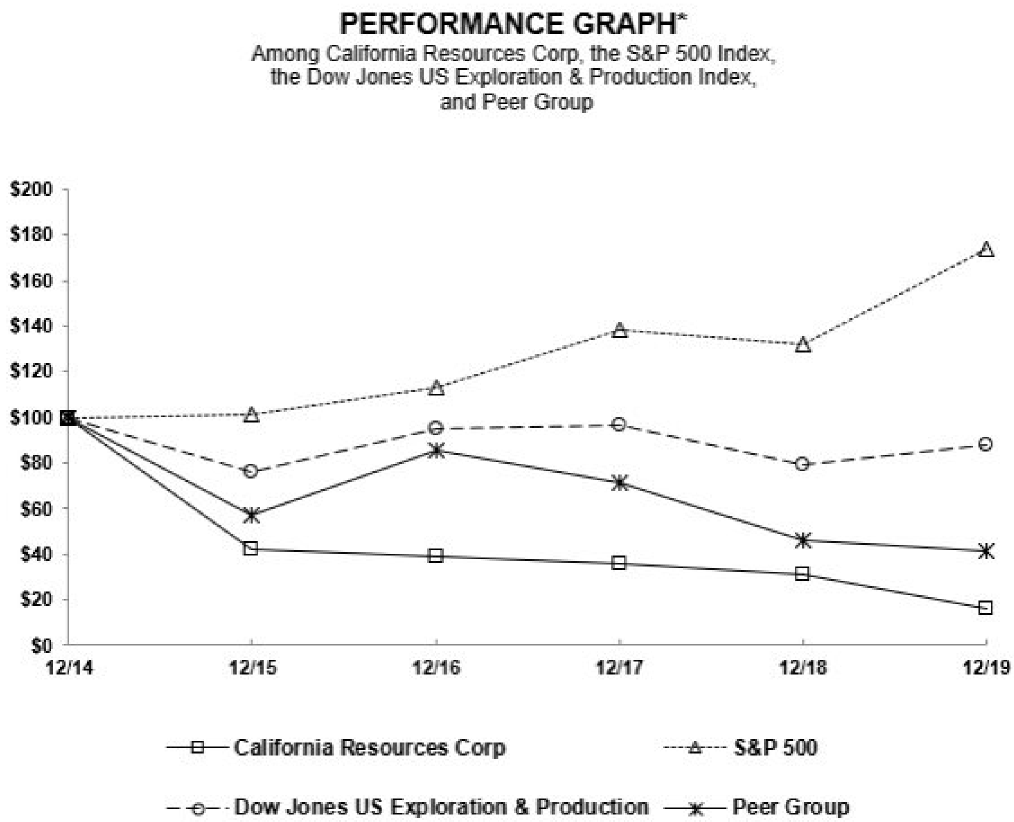
(3) Includes 451,412 shares available under our 2014 Employee Stock Purchase Plan for purchase at 85% of the lower of the market price at either (i) the beginning of a quarter or (ii) the end of a quarter.

(4) Represents the maximum number of shares issuable under the warrant agreement. The holder may elect to net settle shares issued upon exercise of the warrant, in which case the number of shares issued, if any, will be less than the amount shown.

Performance Graph

The following graph compares the cumulative total return to stockholders on our common stock relative to the cumulative total returns of the S&P 500 and Dow Jones U.S. Exploration and Production indexes and our peer groups (with reinvestment of all dividends). The graph assumes that on December 31, 2014, $100 was invested in our common stock, in each index and in each of the peer group companies' common stock weighted by their relative market values within the peer group, and that all dividends were reinvested. The results shown are based on historical results and are not intended to suggest future performance.

Our 2019 peer group consists of Cabot Oil & Gas Corporation; Callon Petroleum Company; Carrizo Oil & Gas, Inc.; Cimarex Energy Co.; Denbury Resources, Inc.; Diamondback Energy, Inc.; EP Energy Corporation; Gulfport Energy Corporation; Laredo Petroleum, Inc.; Matador Resources Company; Murphy Oil Corporation; Newfield Exploration Company; Oasis Petroleum Inc.; Parsley Energy, Inc.; PDC Energy, Inc.; QEP Resources, Inc.; Range Resources Corporation; SM Energy Company; Southwestern Energy Company; Whiting Petroleum Corporation and WPX Energy, Inc. Excluded from the table below are Carrizo Oil & Gas, Inc. and Newfield Exploration Company, which were acquired by Callon Petroleum Company and Encana Corporation, respectively, in 2019.



	December 31,					
	2014	2015	2016	2017	2018	2019
CRC	$ 100	$ 43	$ 39	$ 35	$ 31	$ 16
S&P 500	$ 100	$ 101	$ 114	$ 138	$ 132	$ 174
Dow Jones US Exploration & Production	$ 100	$ 76	$ 95	$ 96	$ 79	$ 88
2019 Peer Group	$ 95	$ 57	$ 85	$ 71	$ 46	$ 41

* 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

The following table presents selected consolidated financial data that should be read in conjunction with the consolidated financial statements and notes thereto included in *Part II, Item 8 – Financial Statements and Supplementary Data* of this report.

	Year Ended December 31,				
	2019	2018	2017	2016	2015
Statements of Operations	(in millions, except for per share data)				
Revenues	$ 2,634	$ 3,064	$ 2,006	$ 1,547	$ 2,403
Net income (loss)	$ 99	$ 429	$ (262)	$ 279	$ (3,554) [(a)]
Net (loss) income attributable to common stock	$ (28)	$ 328	$ (266)	$ 279	$ (3,554) [(a)]
Per common share					
Basic	$ (0.57)	$ 6.77	$ (6.26)	$ 6.76	$ (92.79)
Diluted	$ (0.57)	$ 6.77	$ (6.26)	$ 6.76	$ (92.79)
Statements of Cash Flows					
Net cash provided by operating activities	$ 676	$ 461	$ 248	$ 130	$ 403
Capital investments	$ (455)	$ (690)	$ (371)	$ (75)	$ (401)
Acquisitions and other	$ (18)	$ (553) [(b)]	$ (2)	$ —	$ (151)
Debt transactions, (decrease) increase in debt	$ (181)	$ (26)	$ (18)	$ (73)	$ 356
Contributions from noncontrolling interest holders, net	$ 49	$ 796	$ 98	$ —	$ —
Distributions paid to noncontrolling interest holders	$ (151)	$ (121)	$ (8)	$ —	$ —
Dividends per common share	$ —	$ —	$ —	$ —	$ 0.30

(a) Includes asset impairments of $3.2 billion, net of $1.7 billion tax benefit.
(b) Includes the acquisition of the remaining working, surface and mineral interests in the Elk Hills unit from Chevron U.S.A., Inc. For more information, see *Part II, Item 8 Financial Statements and Supplementary Data, Note 4 Acquisitions and Divestitures.*

	As of December 31,				
	2019	2018	2017	2016	2015
Balance Sheets	(in millions)				
Current assets	$ 491	$ 640	$ 483	$ 425	$ 438
Property, plant and equipment, net	$ 6,352	$ 6,455	$ 5,696	$ 5,885	$ 6,312
Total assets	$ 6,958	$ 7,158	$ 6,207	$ 6,354	$ 7,053
Current liabilities	$ 709	$ 607	$ 732	$ 726	$ 605
Long-term debt	$ 4,877	$ 5,251	$ 5,306	$ 5,168	$ 6,043
Deferred gain and issuance costs, net	$ 146	$ 216	$ 287	$ 397	$ 491
Other long-term liabilities	$ 720	$ 575	$ 602	$ 620	$ 830
Mezzanine equity	$ 802	$ 756	$ —	$ —	$ —
Equity attributable to common stock	$ (389)	$ (361)	$ (814)	$ (557)	$ (916)

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

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

The following discussion should be read in conjunction with the other sections of this 2019 10-K, including *Part I, Item 1A – Risk Factors* and *Part II, Item 8 – Financial Statements and Supplementary Data.*

Basis of Presentation and Certain Factors Affecting Comparability

All financial information presented consists of our consolidated results of operations, financial position and cash flows unless otherwise indicated. The assets and liabilities in the consolidated financial statements are presented on a historical cost basis. We have eliminated all significant intercompany transactions and accounts. We account for our share of oil and natural gas production activities, 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 our balance sheets and statements of operations and cash flows.

Production and Prices

The following table sets forth our average net production volumes of oil, NGLs and natural gas per day for the years ended December 31, 2019, 2018 and 2017:

	2019	2018	2017
	Net[(a)]	**Net[(a)]**	**Net[(a)]**
Oil (MBbl/d)			
San Joaquin Basin	52	53	52
Los Angeles Basin	24	25	27
Ventura Basin	4	4	4
Total	80	82	83
NGLs (MBbl/d)			
San Joaquin Basin	15	15	15
Ventura Basin	—	1	1
Total	15	16	16
Natural gas (MMcf/d)			
San Joaquin Basin	162	165	140
Los Angeles Basin	2	1	1
Ventura Basin	5	7	8
Sacramento Basin	28	29	33
Total	197	202	182
Total Production (MBoe/d)[(a)(b)]	128	132	129

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) Our acquisition of the remaining working interest in the Elk Hills unit added approximately 10 MBoe/d and 8 MBoe/d in 2019 and 2018, respectively. Our divestiture of a 50% working interest in certain zones within our Lost Hills field resulted in a decrease of approximately 2 MBoe/d beginning in 2019. PSC-type contracts had no impact on our oil production in 2019 compared to 2018. Our PSC-type contracts negatively impacted our oil production in 2018 by over 1 MBoe/d compared to 2017.

(b) Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of natural gas to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

Our operating results and those of the oil and natural gas industry as a whole are heavily influenced by commodity prices. Oil and natural gas prices and differentials may fluctuate significantly as a result of numerous market-related variables. These and other factors make it impossible to predict realized prices reliably. The following table sets forth average benchmark prices, average realized prices and price realizations as a percentage of average benchmark prices for our products for the years ended December 31, 2019, 2018 and 2017:

	2019		2018		2017	
	Price	Realization	Price	Realization	Price	Realization
Oil ($ per Bbl)						
Brent	$ 64.18		$ 71.53		$ 54.82	
Realized price without hedge	$ 64.83	101%	$ 70.11	98%	$ 51.47	94%
Settled hedges	3.82		(7.51)		(0.23)	
Realized price with hedge	$ 68.65	107%	$ 62.60	88%	$ 51.24	93%
WTI	$ 57.03		$ 64.77		$ 50.95	
Realized price without hedge	$ 64.83	114%	$ 70.11	108%	$ 51.47	101%
Realized price with hedge	$ 68.65	120%	$ 62.60	97%	$ 51.24	101%
NGLs ($ per Bbl)						
Realized price[(a)]	$ 31.71	49%	$ 43.67	61%	$ 35.76	65%
Realized price[(b)]	$ 31.71	56%	$ 43.67	67%	$ 35.76	70%
Natural gas						
NYMEX ($/MMBTU)	$ 2.67		$ 2.97		$ 3.09	
Realized price without hedge ($/Mcf)	$ 2.87	107%	$ 3.00	101%	$ 2.67	86%
Settled hedges	(0.01)		(0.02)		—	
Realized price with hedge ($/Mcf)	$ 2.86	107%	$ 2.98	100%	$ 2.67	86%

Note: We adopted a new revenue recognition standard on January 1, 2018 that required certain sales-related costs to be reported as expense as opposed to being netted against revenue. The adoption of this standard did not affect net income. Results for reporting periods beginning January 1, 2018 are presented under the new accounting standard while prior periods are not adjusted and continue to be reported under accounting standards in effect for the applicable period.

(a) Realization is calculated as a percentage of Brent.

(b) Realization is calculated as a percentage of WTI.

Joint Ventures

We have entered into a number of joint ventures that allow us to use outside sources of capital to accelerate the development of our assets while providing us with operational and financial flexibility as well as near-term production benefits.

Development Joint Ventures

Alpine JV

In July 2019, we entered into a development joint venture with Alpine Energy Capital, LLC (Alpine) to develop portions of our Elk Hills field (Alpine JV). Alpine is a joint venture between subsidiaries of Colony Capital, Inc. (Colony) and Equity Group Investments. Alpine committed to invest $320 million, which may be increased to a total investment of $500 million, subject to the mutual agreement of the parties. The initial commitment is expected to be invested over a period of up to three years in accordance with a 275-well development plan. Alpine will fund 100% of the drilling and completion costs of these wells, in which they will earn a 90% working interest. If Alpine receives an agreed upon return, our working interest in those wells will increase from 10% to 82.5%. Our consolidated financial statements reflect only our working interest share in the productive wells.

In connection with the Alpine JV, Colony received a warrant to purchase up to 1.25 million shares of our common stock at an exercise price of $40 per share. Colony will be entitled to exercise the warrant in tranches as funding milestones are achieved. The value of each tranche is recognized in our consolidated balance sheets when a funding milestone begins. Each tranche has a five-year term commencing on the date on which such tranche becomes exercisable. As of December 31, 2019, 200,000 shares of our common stock were exercisable under this warrant. Colony may elect, in its sole discretion, to pay cash or to exercise the warrant on a cashless basis, pursuant to which Colony will not be required to pay cash for shares of our common stock upon exercise of the warrant but will instead receive fewer shares.

Royale JV

In October 2018, we entered into a three-year development joint venture for a 20-well program with Royale Energy, Inc. (Royale) where Royale committed approximately $23 million, of which $8 million has been funded to date. We committed to investing approximately $13 million, of which $4 million has been funded to date. Our consolidated results reflect only our 40% working interest share of production from these wells.

MIRA JV

In April 2017, we entered into a development joint venture with Macquarie Infrastructure and Real Assets Inc. (MIRA) to develop certain of our oil and natural gas properties in exchange for a 90% working interest in the related properties (MIRA JV). MIRA funded 100% of the drilling and completion costs of agreed-upon wells in the drilling program. Our 10% working interest increases to 75% if MIRA receives cash distributions equal to a predetermined threshold return. Of the initial $140 million agreed-upon capital commitment, $138 million was funded through December 31, 2019. Our consolidated results reflect only our working interest share in the productive wells.

BSP JV

In February 2017, we entered into a development joint venture with Benefit Street Partners (BSP) where BSP cumulatively contributed $200 million over a period of approximately two years in exchange for preferred interests in the BSP JV (BSP JV). BSP is entitled to preferential distributions and, if BSP receives cash distributions equal to a predetermined threshold, the preferred interest is automatically redeemed in full with no additional payment. The funds contributed by BSP were used to develop certain of our oil and natural gas properties.

The BSP JV holds net profits interests (NPI) in existing and future cash flow from certain of our properties and the proceeds from the NPI are used by the BSP JV to (1) pay quarterly minimum distributions to BSP, (2) make additional distributions to BSP until the predetermined threshold is achieved, and (3) pay for development costs within the project area, upon mutual agreement between members. Our consolidated results reflect the full operations of the BSP JV, with BSP's share of net income reported in net income attributable to noncontrolling interests on our consolidated statements of operations.

The following table summarizes the cumulative investment through December 31, 2019 by our development joint venture partners, before transaction costs:

	Cumulative Investment through December 31, 2019
	(in millions)
Alpine	$ 134
Royale	8
MIRA	138
BSP	200
Total Capital	**$ 480**

Midstream JV

Ares JV

In February 2018, we entered into a midstream joint venture with ECR Corporate Holdings L.P. (ECR), a portfolio company of Ares Management L.P. (Ares). This joint venture (Ares JV) holds the Elk Hills power plant (a 550-megawatt natural gas fired power plant) and a 200 MMcf/d cryogenic gas processing plant. We hold 50% of the Class A common interest and 95.25% of the Class C common interest in the Ares JV. ECR holds 50% of the Class A common interest, 100% of the Class B preferred interest and 4.75% of the Class C common interest. We received $750 million in proceeds upon entering into the Ares JV, before $3 million of transaction costs.

The Class A common and Class B preferred interests held by ECR are reported as redeemable noncontrolling interests in mezzanine equity due to an embedded optional redemption feature. The Class C common interest held by ECR is reported in equity on our consolidated balance sheets.

The Ares JV is required to make monthly distributions to the Class B holder. The Class B preferred interest has a deferred payment feature whereby a portion of the monthly distributions may be deferred for the first three years to the fourth and fifth year. The deferred amounts accrue an additional return. Distributions to the Class B preferred interest holders are reported as a reduction to mezzanine equity on our consolidated balance sheets. Monthly, the Ares JV is required to distribute its excess cash flow over its working capital requirements to the Class C common interests on a pro-rata basis.

We can cause the Ares JV to redeem ECR's Class A and Class B interests, in whole, but not in part, at any time by paying $750 million for the Class B interest and $60 million for the Class A interest, plus any previously accrued but unpaid preferred distributions and a make-whole payment if the redemption happens prior to five years from inception. We have the option to extend the redemption period for up to an additional two and one-half years, in which case the interests can be redeemed for $750 million for the Class B interest and $80 million for the Class A interest, plus any previously accrued but unpaid preferred distributions and a make-whole payment if the redemption happens prior to seven and one-half years from inception. If we do not exercise a redemption at the end of the seven and one-half year period, ECR can either sell its Class A and Class B interests or cause the sale or lease of the Ares JV assets.

Our consolidated statements of operations reflect the full operations of our Ares JV, with ECR's share of net income reported in net income attributable to noncontrolling interests.

Additionally, in the first quarter of 2018, an Ares-led investor group purchased approximately 2.3 million shares of our common stock in a private placement for an aggregate purchase price of $50 million.

Exploration JVs

Since 2016, we have entered into multiple exploration joint ventures that have allowed us to successfully explore multiple, diverse conventional exploration prospects with industry-leading success with minimal internally funded capital. In 2019, we drilled three exploration prospects with our partners under these agreements.

We entered into additional exploration joint ventures in 2019 that generally provided for our partners to invest in seismic and/or drilling activity across our assets on a promoted basis.

Acquisitions and Divestitures

Acquisitions

In April 2018, we acquired from Chevron U.S.A., Inc. (Chevron) its share of the remaining working, surface and mineral interests in the approximately 47,000-acre Elk Hills unit (the Elk Hills transaction) for approximately $518 million, including $7 million of liabilities assumed relating to asset retirement obligations. We accounted for the Elk Hills transaction as a business combination and allocated $435 million to proved properties, $77 million to other property, plant and equipment and $6 million to materials and supplies. The consideration paid consisted of $460 million in cash and 2.85 million shares of CRC common stock issued at the close of the transaction (valued at $51 million).

As part of the Elk Hills transaction, Chevron reduced its royalty interest in one of our oil and natural gas properties by half and extended the time frame to invest the remainder of our capital commitment on that property by two years, to the end of 2020. As of December 31, 2019, our remaining commitment was approximately $12 million. In addition, the parties mutually agreed to release each other from pending claims with respect to the former Elk Hills unit.

In April 2018, we acquired an office building and land in Bakersfield, California for $48 million. For the initial eight months in 2018, a former owner of the building occupied most of the space as a tenant, from which we generated approximately $4 million in rental income. In December 2018, this tenant downsized the space they are leasing through December 2022, with a corresponding reduction in rent. The vacated space not used by us will be available to lease to other tenants to generate additional income. In addition, the unimproved land may be monetized in the future. Approximately $6 million of the purchase price was allocated to the in-place leases, which is included in other assets and is being amortized into other expenses, net.

Additionally, we had several other acquisitions totaling approximately $6 million in 2019 and $39 million in 2018.

Divestitures

In May 2019, we sold 50% of our working interest and transferred operatorship in certain zones within our Lost Hills field, located in the San Joaquin basin, for total consideration in excess of $200 million, consisting of approximately $168 million and a carried 200-well development program to be drilled through 2023 with an estimated value of $35 million (Lost Hills divestiture). We received cash proceeds of $164 million after transaction costs and purchase price adjustments, which were used to pay down our 2014 Revolving Credit Facility.

In 2018, we divested non-core assets resulting in $18 million of proceeds and a $5 million gain. In 2017, we divested non-core assets resulting in $33 million of proceeds and a $21 million gain.

Seasonality

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

Income Taxes

All of our income is earned from domestic operations and is subject to tax in the United States. We did not record a significant income tax provision (benefit) in any of the years ended December 31, 2019, 2018 and 2017.

Our effective tax rate differs from the amounts computed by applying the U.S. federal statutory tax rate to pre-tax income (loss) as follows:

	For the years ended December 31,		
	2019	2018	2017
U.S. federal statutory tax rate	21 %	21 %	(35)%
State income taxes, net	7	6	(6)
Exclusion of tax attributable to noncontrolling interests, net	(35)	(5)	—
Decrease in U.S. federal corporate tax rate	—	—	91
Tax credits, net	(9)	(6)	(19)
Nondeductible compensation, net	3	—	—
Stock-based compensation, net	—	—	1
Change in valuation allowance, net	14	(17)	(33)
Other, net	—	1	1
Effective tax rate	1 %	— %	— %

Our effective tax rate is primarily affected by state income taxes, income included in our consolidated results which is taxed to noncontrolling interests and the benefit of income tax credits. Our U.S. federal deferred tax assets and liabilities were remeasured due to the reduction of the top corporate tax rate from 35% to 21% under the Tax Cuts and Jobs Act (TCJA) enacted on December 22, 2017. The TCJA also included significant changes to the deduction for executive compensation by public corporations. Given our income tax position, any item affecting our effective tax rate described above is generally offset by an equal change in the valuation allowance.

Under the TCJA, for taxable years beginning in 2018, our deduction for business interest is limited to 30% of our adjusted taxable income. For purposes of this limitation, adjusted taxable income is computed without regard to net business interest expense and, in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization or depletion. Proposed Treasury Regulations issued in December 2018 provide that depreciation, amortization or depletion expense that is capitalized to inventory is not treated as depreciation, amortization or depletion for the purposes of computing adjustable taxable income. It is reasonably possible that the composition of our deferred tax assets, specifically the amount reported for net operating loss and business interest expense carryforwards, could significantly change when the Internal Revenue Service finalizes and issues regulations. Our carryforwards for business interest expense do not expire.

Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit use of existing deferred tax assets. A significant piece of evidence evaluated is a history of operating losses. Such evidence limits our ability to consider other evidence such as projections for growth. As of December 31, 2019, we concluded that we could not realize, on a more-likely-than-not basis, any of our deferred tax assets and there is not sufficient evidence to support the reversal of all or any portion of this allowance. Given our recent and anticipated future earnings trends, we do not believe any of the valuation allowance as of December 31, 2019 will be released within the next 12 months. Changes in assumptions or changes in tax laws and regulations could materially affect the recognized amounts of valuation allowance.

We paid approximately $1 million to California for alternative minimum taxes in 2019. We did not make any United States federal and state income tax payments in 2018 or 2017. We do not expect to make any significant income tax payments in the foreseeable future, although this estimate could change.

For additional information on tax-related items, see information set forth in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 10 Income Taxes*.

Balance Sheet Analysis

Balance sheet components and changes in these components as of December 31, 2019 and 2018, are discussed below:

	2019	2018
	(in millions)	
Cash	$ 17	$ 17
Trade receivables	$ 277	$ 299
Inventories	$ 67	$ 69
Other current assets, net	$ 130	$ 255
Property, plant and equipment, net	$ 6,352	$ 6,455
Other assets	$ 115	$ 63
Current maturities of long-term debt	$ 100	$ —
Accounts payable	$ 296	$ 390
Accrued liabilities	$ 313	$ 217
Long-term debt	$ 4,877	$ 5,251
Deferred gain and issuance costs, net	$ 146	$ 216
Other long-term liabilities	$ 720	$ 575
Mezzanine equity	$ 802	$ 756
Equity attributable to common stock	$ (389)	$ (361)
Equity attributable to noncontrolling interests	$ 93	$ 114

Cash at December 31, 2019 and 2018 included $3 million and $2 million, respectively, that is restricted under one of our joint venture agreements. See *Liquidity and Capital Resources* for our cash flow analysis.

The decrease in trade receivables was largely driven by lower natural gas trading activity in December 2019 as compared with December 2018, as well as a decline in production and natural gas and NGL realized prices in the fourth quarter of 2019 compared to the fourth quarter of 2018. These decreases were partially offset by higher realized oil prices in December 2019 compared to December 2018.

The decrease in other current assets, net primarily reflected a decrease in the fair value of the current portion of our derivative assets, which primarily resulted from a lower percentage of our oil production hedged between comparative periods.

The decrease in property, plant and equipment, net primarily resulted from depreciation, depletion and amortization (DD&A) and the Lost Hills divestiture, partially offset by capital investments and increases in our asset retirement obligations (ARO) resulting from idle well regulations enacted in the first quarter of 2019.

The increase in other assets was primarily due to recording a long-term operating lease asset as a result of accounting rules adopted on January 1, 2019 and prepaid power plant major maintenance, partially offset by a decrease in the fair value of long-term derivative assets.

Current maturities of long-term debt reflected $100 million for our 5% senior notes due in January 2020, which were repaid in full upon maturity.

The decrease in accounts payable at December 31, 2019 compared to December 31, 2018 reflected the decrease in capital investments and gas-trading activities, which were lower in the fourth quarter of 2019 compared to the fourth quarter of 2018.

The increase in accrued liabilities reflected the current portion of our operating lease liability resulting from the adoption of new lease accounting rules, the timing of payments due to our joint venture partners, severance costs related to our October 2019 organizational restructure and increased obligation to purchase greenhouse gas allowances.

Long-term debt decreased due to repurchases of our Second Lien Notes, reclassification of $100 million of our Senior Notes to current maturities of long-term debt, pay down of the 2014 Revolving Credit Facility from the proceeds of the Lost Hills divestiture and positive cash flow.

The decrease in deferred gain and issuance costs, net was largely the result of repurchases of our Second Lien Notes and amortization.

Other long-term liabilities reflected the increase in ARO primarily due to idle well regulations enacted in the first quarter of 2019, long-term operating lease liabilities due to the adoption of new lease accounting rules and postretirement benefits primarily resulting from the October 2019 organizational restructure. The annual incremental cash expenditures for ARO resulting from the idle well regulations and postretirement benefits resulting from the October 2019 organizational restructure are not expected to be material in the foreseeable future.

Mezzanine equity reflected the carrying amount of the Class A common and Class B preferred interests held by ECR in our midstream JV.

Equity attributable to common stock decreased as a result of a decrease in net income between periods and an increase in the income allocated to ECR for a full 12 months in 2019 as compared to nine months in the prior year.

Equity attributable to noncontrolling interests includes the Class C interest in the midstream joint venture held by ECR and BSP's preferred interest in the BSP JV. The decrease in 2019 primarily related to distributions to the noncontrolling interest holders.

Statement of Operations Analysis

Results of Oil and Natural Gas Operations

The following represents key operating data for our oil and natural gas operations, excluding corporate items, on a per Boe basis for the years ended December 31, 2019, 2018 and 2017:

	2019	2018	2017
Production costs	$ 19.16	$ 18.88	$ 18.64
Production costs, excluding effects of PSC-type contracts[(a)]	$ 17.70	$ 17.47	$ 17.48
Field general and administrative expenses[(b)]	$ 1.20	$ 1.01	$ 0.70
Field depreciation, depletion and amortization	$ 9.40	$ 9.71	$ 10.85
Field taxes other than on income	$ 2.59	$ 2.42	$ 2.34

(a) As described in *Items 1 and 2 – Business and Properties – Operations – Production, Price and Cost History*, the reporting of our PSC-type contracts creates a difference between reported production costs, which are for the full field, and reported volumes, which are only our net share, inflating the per barrel production costs. These amounts represent our production costs after adjusting for this difference.

(b) Field general and administrative expenses increased in 2019 compared to 2018, primarily due to the Elk Hills transaction that occurred in April 2018 since certain costs are no longer recovered from our former working interest partner. Our 2019 costs include 12 months without such cost recovery compared to nine months without cost recovery in 2018.
Field general and administrative expenses also increased in 2018 compared to 2017 primarily due to the Elk Hills transaction, with 2018 costs including nine months without cost recovery compared to 12 months of cost recovery in 2017.

Consolidated Results of Operations

The following represents key operating data for consolidated operations for the years ended December 31, 2019, 2018 and 2017:

	2019	2018	2017
		(in millions)	
Oil and natural gas sales[(a)]	$ 2,270	$ 2,590	$ 1,936
Net derivative (loss) gain from commodity contracts	(59)	1	(90)
Other revenue[(a)]	423	473	160
Production costs	(895)	(912)	(876)
General and administrative expenses[(b)]	(290)	(299)	(249)
Depreciation, depletion and amortization	(471)	(502)	(544)
Taxes other than on income	(157)	(149)	(136)
Exploration expense	(29)	(34)	(22)
Other expenses, net[(a)]	(363)	(399)	(106)
Interest and debt expense, net	(383)	(379)	(343)
Net gain on early extinguishment of debt	126	57	4
Gain on asset divestitures	—	5	21
Other non-operating expenses[(b)]	(72)	(23)	(17)
Income (loss) before income taxes	100	429	(262)
Income tax provision	(1)	—	—
Net income (loss)	99	429	(262)
Net income attributable to noncontrolling interests	$ (127)	$ (101)	$ (4)
Net (loss) income attributable to common stock	$ (28)	$ 328	$ (266)
Adjusted net income (loss)[(c)]	$ 70	$ 61	$ (187)
Adjusted EBITDAX[(c)]	$ 1,142	$ 1,117	$ 779
Effective tax rate	1%	—%	—%

(a) We adopted the revenue recognition standard on January 1, 2018 that required certain sales-related costs to be reported as expense as opposed to being netted against revenue. The adoption of this standard did not affect net income. Results for reporting periods beginning January 1, 2018 are presented under the new accounting standard while prior periods are not adjusted and continue to be reported under accounting standards in effect for the applicable period.

(b) New accounting rules related to the presentation of net periodic benefit costs for pension and postretirement benefits in the Consolidated Statements of Operations were adopted on January 1, 2018. For the year ended December 31, 2017, certain pension benefit costs of $10 million were reclassified from general and administrative expenses to other non-operating expenses to conform with the new rules.

(c) Adjusted net income (loss) and Adjusted EBITDAX are non-GAAP measures. See the *Non-GAAP Financial Measures* section below for a reconciliations to their nearest GAAP measures.

Year Ended December 31, 2019 vs. 2018

Oil and natural gas sales – Oil and natural gas sales, excluding the impact of settled hedges, decreased 12%, or $320 million, in 2019 compared to 2018, due to changes in realized prices and production as reflected in the following table:

	Oil	NGLs	Natural Gas	Total
		(in millions)		
Year ended December 31, 2018	$ 2,110	$ 260	$ 220	$ 2,590
Changes in realized prices	(159)	(71)	(9)	(239)
Changes in production	(67)	(10)	(4)	(81)
Year ended December 31, 2019	$ 1,884	$ 179	$ 207	$ 2,270

Note: See *Production and Prices* for average benchmark and realized prices, realizations and production.

The effect of settled hedges is not included in the table above. Proceeds from settled hedges were $111 million for the year ended December 31, 2019 compared to payments of $228 million in 2018, which had a positive impact of $339 million on our total revenue between years. Including the effect of settled hedges, our oil and natural gas sales increased by $19 million or 1% compared to the same period of 2018.

Net derivative (loss) gain from commodity contracts – Net derivative loss from commodity contracts was $59 million for the year ended December 31, 2019 compared to a gain of $1 million in the same period of 2018, representing an overall change of $60 million as reflected in the following table. The non-cash changes in the fair value of our outstanding derivatives resulted from the positions held as well as the relationship between contract prices and the associated forward curves at the end of each year.

	Year ended December 31,	
	2019	**2018**
	(in millions)	
Non-cash derivative (loss) gain, excluding noncontrolling interest	$ (166)	$ 224
Non-cash derivative (loss) gain, noncontrolling interest	(4)	5
Total non-cash changes	(170)	229
Net proceeds (payments) on settled commodity derivatives	111	(228)
Net derivative (loss) gain from commodity contracts	$ (59)	$ 1

Other revenue – Other revenue was $423 million for the year ended December 31, 2019 compared to $473 million in the same period of 2018, representing a decrease of $50 million as reflected in the following table. This decrease was largely the result of lower trading activity in 2019; however, the operating margin before transportation charges in 2019 was $85 million compared to $80 million in 2018.

	Year ended December 31,	
	2019	**2018**
	(in millions)	
Trading	$ 286	$ 330
Electricity sales	112	111
Other	25	32
Total other revenue	$ 423	$ 473

Production costs – Production costs for the year ended December 31, 2019 decreased $17 million to $895 million, compared to $912 million for the same period of 2018, resulting in a 2% decrease. The decrease primarily related to cost savings resulting from our October 2019 organizational redesign and less downhole maintenance activity in 2019 compared to the prior year.

General and administrative expenses – Our general and administrative expenses decreased $9 million to $290 million for the year ended December 31, 2019 compared to the same period of 2018, predominantly due to cost savings attributable to our October 2019 organizational redesign and lower cash-settled stock-based compensation expense resulting from the approximately $8 decline in our stock price at December 31, 2019 compared to December 31, 2018. See the *Stock-Based Compensation* section below.

Other expenses, net – Other expenses, net was $363 million for the year ended December 31, 2019 compared to $399 million for the same period of 2018, representing a decrease of $36 million as reflected in the following table. The decrease was largely the result of lower trading activity, partially offset by higher Elk Hills Power costs and transportation costs.

	Year ended December 31,	
	2019	**2018**
	(in millions)	
Trading purchases	$ 201	$ 250
Elk Hills Power costs	68	61
Transportation costs	40	36
Other expenses	54	52
Total other expenses, net	$ 363	$ 399

Other non-operating expenses – Other non-operating expenses for the year ended December 31, 2019 increased $49 million to $72 million, compared to $23 million for the same period of 2018, resulting in an approximately 200% increase. This increase was primarily due to the implementation of fourth quarter 2019 operational efficiencies and an organizational redesign that reduced our workforce to approximately 1,250 employees, which is slightly more than half the employees we had at the time of our inception in 2014. We recorded a charge to other non-operating expenses of $41 million, consisting of $29 million in salary and severance expense and $12 million for other termination benefits.

Net income attributable to noncontrolling interests – The increase in net income attributable to noncontrolling interests of $26 million reflected the additional net income (loss) allocated to ECR for the full year of 2019 compared to 2018 starting in April, partially offset by the change in the fair value of derivative instruments held by the BSP JV in 2019.

Stock-Based Compensation

Our consolidated results of operations for the years ended December 31, 2019 and 2018 include the effects of long-term stock-based compensation plans under which awards are granted annually to executives, non-executive employees and non-employee directors that are either settled with shares of our common stock or cash. Our equity-settled awards granted to executives include stock options, restricted stock units and performance stock units that either cliff vest at the end of a three-year period or vest ratably over a three-year period, some of which are partially settled in cash. Our equity-settled awards granted to non-employee directors are stock grants that vest immediately or restricted stock units that cliff vest after one year. Our cash-settled awards granted to non-executive employees vest ratably over a three-year period.

Changes in our stock price introduce volatility in our results of operations because we pay cash-settled awards based on our stock price on the vesting date and accounting rules require that we adjust our obligation for unvested awards to the amount that would be paid using our stock price at the end of each reporting period. Cash-settled awards, including executive awards partially settled in cash, account for almost 70% of our total outstanding awards. Equity-settled awards are not similarly adjusted for changes in our stock price.

Our ending stock price for each of the quarters in 2019 and 2018 was as follows:

	2019	2018
First quarter	$ 25.71	$ 17.15
Second quarter	$ 19.68	$ 45.44
Third quarter	$ 10.20	$ 48.53
Fourth quarter	$ 9.03	$ 17.04

Stock-based compensation is included in both G&A expenses and production costs as shown in the table below (in millions, except per Boe amounts):

	2019	2018
G&A expenses		
Cash-settled awards	$ 14	$ 23
Equity-settled awards	11	13
Total stock-based compensation in G&A	$ 25	$ 36
Total stock-based compensation in G&A per Boe	$ 0.54	$ 0.75
Production costs		
Cash-settled awards	$ 4	$ 6
Equity-settled awards	3	3
Total stock-based compensation in production costs	$ 7	$ 9
Total stock-based compensation in production costs per Boe	$ 0.15	$ 0.19
Total stock-based compensation	$ 32	$ 45
Total stock-based compensation per Boe	$ 0.69	$ 0.94

Year Ended December 31, 2018 vs. 2017

See *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Statement of Operations Analysis* in our 2018 Form 10-K for our analysis of the changes in our consolidated statements of operations for the year ended December 31, 2018 compared to December 31, 2017.

Non-GAAP Financial Measures

Adjusted net income (loss) – Our results of operations, which are presented in accordance with U.S. generally accepted accounting principles (GAAP), can include the effects of unusual, out-of-period and infrequent transactions and events affecting earnings that vary widely and unpredictably (in particular certain non-cash items such as derivative gains and losses) in nature, timing, amount and frequency. Therefore, management uses a measure called adjusted net income (loss) that excludes those items. This measure is not meant to disassociate these items from management's performance but rather is meant to provide useful information to investors interested in comparing our performance between periods. Reported earnings are considered representative of management's performance over the long term. Adjusted net income (loss) is not considered to be an alternative to net income (loss) reported in accordance with GAAP.

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

	2019	2018	2017
	(in millions, except share data)		
Net income (loss)	$ 99	$ 429	$ (262)
Net income attributable to noncontrolling interests	(127)	(101)	(4)
Net (loss) income attributable to common stock	(28)	328	(266)
Unusual, infrequent and other items:			
Non-cash derivative loss (gain) from commodities, excluding noncontrolling interest	166	(224)	78
Non-cash derivative loss from interest-rate contracts	4	6	—
Severance and termination benefits	47	4	5
Net gain on early extinguishment of debt	(126)	(57)	(4)
Gain on asset divestitures	—	(5)	(21)
Other, net	7	9	21
Total unusual, infrequent and other items	98	(267)	79
Adjusted net income (loss)	$ 70	$ 61	$ (187)
Net (loss) income attributable to common stock per diluted share	$ (0.57)	$ 6.77	$ (6.26)
Adjusted net income (loss) per diluted share	$ 1.40	$ 1.27	$ (4.40)

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

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

	2019	2018	2017
		(in millions)	
Net income (loss)	$ 99	$ 429	$ (262)
Interest and debt expense, net	383	379	343
Depreciation, depletion and amortization	471	502	544
Exploration expense	29	34	22
Unusual, infrequent and other items	98	(267)	79
Other non-cash items	62	40	53
Adjusted EBITDAX	$ 1,142	$ 1,117	$ 779

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

	2019	2018	2017
		(in millions)	
Net cash provided by operating activities	$ 676	$ 461	$ 248
Cash interest	439	441	396
Exploration expenditures	18	17	20
Working capital changes	8	199	94
Other, net	1	(1)	21
Adjusted EBITDAX	$ 1,142	$ 1,117	$ 779

Liquidity and Capital Resources

Cash Flow Analysis

	2019	2018
	(in millions)	
Net cash provided by operating activities	$ 676	$ 461
Net cash used in investing activities:		
Capital investments	$ (455)	$ (690)
Changes in capital investment accruals	$ (85)	$ 69
Acquisitions, divestitures and other	$ 146	$ (535)
Net cash (used) provided by financing activities:		
Debt transactions	$ (181)	$ (26)
(Distributions) contributions with noncontrolling interest holders, net	$ (102)	$ 675
Issuance of common stock and other, net	$ 1	$ 43

Cash flows from operating activities – Our net cash provided by operating activities is sensitive to many variables, particularly changes in commodity prices. Commodity price movements may also lead to changes in other variables in our business, including adjustments to our capital program. Our operating cash flow increased 47%, or $215 million, to $676 million for the year ended December 31, 2019 from $461 million in the same period of 2018 primarily due to net proceeds on settled commodity derivatives of $111 million in 2019 compared to payments of $228 million in 2018, which was partially offset by a decrease in oil and gas revenue as a result of lower realized prices and production in 2019.

Changes in operating assets and liabilities increased our operating cash flow in 2019 by $210 million compared to 2018, which was largely the result of purchasing more greenhouse gas allowances in 2018. The increase was also attributable to a decrease in purchased hedges and the timing of payments for capital investments.

Cash flows from investing activities – Our net cash used in investing activities of $394 million for the year ended December 31, 2019 included $455 million of capital investments (excluding $85 million in negative capital-related accrual changes), of which $48 million was funded by BSP. These uses of cash were partially offset by $164 million in proceeds related to the Lost Hills divestiture.

Our net cash used in investing activities of $1,156 million for the year ended December 31, 2018 included $690 million of capital investments (excluding $69 million in positive capital-related accrual changes), of which $49 million was funded by BSP, and $547 million of acquisition costs primarily related to the Elk Hills transaction and a building in Bakersfield. These uses of cash were partially offset by $18 million in proceeds from the sale of non-core assets.

The amounts in the table below reflect our capital investment, excluding changes in capital investment accruals, for the years ended December 31, 2019 and 2018:

	2019	2018
	(in millions)	
Oil and natural gas	$ 379	$ 610
Exploration	9	21
Corporate and other	19	10
Total internally funded capital	407	641
BSP-funded capital	48	49
Total capital	$ 455	$ 690

Cash flows from financing activities – Our net cash used in financing activities of $282 million for the year ended December 31, 2019 primarily resulted from $156 million of debt repurchases on our Second Lien Notes, $151 million of distributions to our noncontrolling interest holders and $23 million in net payments on our 2014 Revolving Credit Facility, partially offset by $49 million in net contributions from BSP.

For the year ended December 31, 2018, our net cash provided by financing activities of $692 million primarily resulted from $796 million in net contributions from our noncontrolling interest holders, $177 million in net borrowings on our 2014 Revolving Credit Facility and $54 million from the issuance of common stock to an Ares-led investor group in connection with the Ares JV, partially offset by $199 million used for debt repurchases on our Senior Notes and $121 million of distributions paid to our noncontrolling interest holders.

Liquidity

Our primary sources of liquidity and capital resources are cash flows from operations and available borrowing capacity under our 2014 Revolving Credit Facility. We also rely on other sources such as joint ventures and non-core asset sales to supplement our capital program and fund other corporate purposes. Our working capital requirements are primarily driven by the level of activity in our business and debt service requirements. Our 2020 capital program will be dynamic and will be adjusted based on realized price trends during the year.

As of December 31, 2019, we had available liquidity of $331 million, which consisted of $14 million in unrestricted cash and $317 million of available borrowing capacity under our 2014 Revolving Credit Facility (before a $150 million month-end minimum liquidity requirement). However, as of December 31, 2019, we had approximately $4.9 billion of debt outstanding, a substantial portion of which will mature in 2021. We have undertaken a variety of measures to reduce debt such as repurchasing outstanding notes and selling non-core assets. We have also increased our margins by reducing our workforce and consolidating our office space.

On February 20, 2020, we launched offers to exchange a significant portion of our Second Lien Notes and senior notes into (1) notes and equity interests issued by a non-consolidated entity that will hold a term royalty interest in our Elk Hills unit and/or (2) a new first-lien last-out Company term loan and warrants convertible into our common stock. If fully subscribed, the transaction would have the effect of reducing our net debt by almost $1 billion. The transaction is expected to close on March 20, 2020.

We are continuing to evaluate and consider a number of additional opportunities to delever, including liability management transactions, monetization of royalty and other property interests and other similar transactions. Such transactions, if any, will depend on prevailing market conditions, contractual restrictions and other factors. Our ability to pay the principal and interest on our long-term debt and to satisfy our other liabilities will depend upon oil and natural gas prices, the success of our development activities, our success with respect to our deleveraging efforts and our ability to refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by the results of our operations, economic and capital market conditions, oil and natural gas prices and other factors, many of which are beyond our control. See “We have significant indebtedness that could limit our financial and operating flexibility and make us more vulnerable in economic downturns,” “Our lenders require us to comply with covenants that limit our borrowing capabilities and could restrict our ability to use or access capital” and "A significant portion of our long-term indebtedness will mature within two years and will likely need to be refinanced. There can be no assurances we will be able to refinance this indebtedness on acceptable terms or at all." in *Part I, Item 1A – Risk Factors* for additional information about our indebtedness and restrictions on our use of and access to capital.

We believe that our operating cash flows and availability under our 2014 Revolving Credit Facility will be sufficient to meet our obligations and working capital requirements for the next 12 months.

Debt

As of December 31, 2019, our long-term debt consisted of the following credit agreements, second lien notes and senior notes:

	Outstanding Principal	Interest Rate[a]	Maturity	Security
	(in millions)			
Credit Agreements				
2014 Revolving Credit Facility	$ 518	LIBOR plus 3.25%-4.00% ABR plus 2.25%-3.00%	June 30, 2021	Shared First-Priority Lien
2017 Credit Agreement	1,300	LIBOR plus 4.75% ABR plus 3.75%	December 31, 2022[b]	Shared First-Priority Lien
2016 Credit Agreement	1,000	LIBOR plus 10.375% ABR plus 9.375%	December 31, 2021	First-Priority Lien
Second Lien Notes				
Second Lien Notes	1,815	8%	December 15, 2022[c]	Second-Priority Lien
Senior Notes				
5% Senior Notes due 2020	100	5%	January 15, 2020	Unsecured
5½% Senior Notes due 2021	100	5.5%	September 15, 2021	Unsecured
6% Senior Notes due 2024	144	6%	November 15, 2024	Unsecured
Total	$ 4,977			
Less: Current Maturities	(100)			
Long-Term Debt	4,877			

(a) London Interbank Offered Rates (LIBOR) will be phased out after 2021 and replaced with the Secured Overnight Financing Rate within the United States for U.S. dollar-based LIBOR. Our credit agreements contemplate a discontinuation of LIBOR and have an alternate borrowing rate. We do not expect the discontinuation of LIBOR to have a significant impact on our carrying charges.

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

(c) The Second Lien Notes require principal repayments of approximately $287 million in June 2021, $57 million in December 2021 and $59 million in June 2022 and $1,412 million in December 2022.

As of December 31, 2019, we had approximately $317 million of available borrowing capacity, subject to a $150 million month-end minimum liquidity requirement. Our 2014 Revolving Credit Facility also includes a sub-limit of $400 million for the issuance of letters of credit. As of December 31, 2019 and 2018, we had letters of credit of approximately $165 million and $162 million, respectively. These letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters.

For additional information on long-term debt, see information set forth in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 6 Debt*.

Derivatives

Commodity Contracts

Our strategy for protecting our cash flow, operating margin and capital program, while maintaining adequate liquidity, also includes our hedging program. We did not have any commodity derivatives designated as accounting hedges as of and during the year ended December 31, 2019. We currently have the following Brent-based crude oil contracts, as of February 26, 2020:

	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Purchased Puts:				
Barrels per day	30,000	20,000	13,000	8,000
Weighted-average price per barrel	$ 70.83	$ 67.50	$ 65.00	$ 65.00
Sold Puts:				
Barrels per day	30,000	20,000	18,000	13,000
Weighted-average price per barrel	$ 56.67	$ 53.75	$ 54.31	$ 53.81
Swaps:				
Barrels per day	—	5,000	5,000	5,000
Weighted-average price per barrel	$ —	$ 70.05	$ 65.00	$ 65.00

Our counterparties have an option to increase volumes by up to 5,000 barrels per day for the second quarter of 2020 at a weighted-average Brent price of $70.05. A counterparty has an option to increase volumes by up to 5,000 barrels per day for the second half of 2020 at a weighted-average Brent price of $65.00.

The BSP JV entered into crude oil derivatives for insignificant volumes through 2021 that are included in our consolidated results but not in the above table. The BSP JV also entered into natural gas swaps for insignificant volumes for periods through May 2021. The hedges entered into by the BSP JV could affect the timing of the reversion of BSP's preferred interest.

Interest-Rate Contracts

In May 2018, we entered into derivative contracts that limit our interest rate exposure with respect to $1.3 billion of our variable-rate indebtedness. These interest rate contracts reset monthly and require the counterparties to pay any excess interest owed on such amount in the event the one-month LIBOR exceeds 2.75% for any monthly period prior to May 4, 2021.

Capital Program

We seek to create value by investing our operating cash flow back into our business. We respond to economic conditions by adjusting the amount and allocation of our capital program while continuing to identify efficiencies and cost savings.

We focus our capital program on oil projects that provide high margins and low decline rates. We believe investing in these projects will generate positive cash flow allowing us to fund future capital programs and grow production over the longer term. Our low decline rates compared to our industry peers together with our high level of operational control give us the flexibility to adjust the level of our capital investments as circumstances warrant.

We develop our capital program by prioritizing life-of-project returns to grow our net asset value over the long term, while balancing the short- and long-term growth potential of each of our assets. We use a Value Creation Index (VCI) metric for project selection and capital allocation across our asset portfolio. We calculate the VCI for each of our projects by dividing the net present value of the project's expected pre-tax cash flow over its life by the net present value of the investments, each using a 10% discount rate. Projects included in our capital program 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 over the life of the project.

Our technical teams are consistently working to enhance value by improving the economics of our inventory through detailed geologic studies as well as application of more effective and efficient drilling and completion techniques. As a result, we expect many projects that do not currently meet our VCI threshold today will do so by the time of development. We regularly monitor internal performance and external factors and adjust our capital investment program with the objective of creating the most value from our asset portfolio.

Actions we have taken to streamline our business and reduce costs enable us to invest in our business to support production. In addition, we will continue to build our inventory of available projects, which we believe will position us to accelerate value by utilizing JV capital and take advantage of potential future commodity price increases.

2019 Capital Program

Sources of our 2019 capital program were as follows:

	2019
	(in millions)
Internally funded capital	$ 407
BSP-funded capital	48
Capital investment included in our financial statements	**455**
MIRA-funded capital	23
Alpine-funded capital	134
Total capital investment	**$ 612**

Our capital program targeted oil-weighted projects in the San Joaquin and Los Angeles basins. The table below sets forth our total 2019 capital program:

	Conventional				Unconventional		
	Primary	Waterflood	Steamflood	Total	Primary	Other	Total Capital Investments
Basin:				(in millions)			
San Joaquin	$ 32	$ 72	$ 40	$ 144	$ 162	$ —	$ 306
Los Angeles	—	93	—	93	—	—	93
Ventura	10	4	—	14	—	—	14
Sacramento	11	—	—	11	—	—	11
Exploration and other	—	—	—	—	—	31	31
Capital included in our financial statements	53	169	40	262	162	31	455
MIRA-funded capital	23	—	—	23	—	—	23
Alpine-funded capital	1	—	57	58	76	—	134
Total	$ 77	$ 169	$ 97	$ 343	$ 238	$ 31	$ 612

The table below sets forth our capital investments by activity type for the year ended December 31, 2019:

	Drilling	Workovers	Facilities	Exploration	Other	Total Capital
			(in millions)			
Internally funded	$ 249	$ 53	$ 77	$ 9	$ 19	$ 407
BSP	45	—	—	3	$ —	$ 48
Capital investments included in our financial statements	294	53	77	12	$ 19	$ 455
MIRA-funded capital	23	—	—	—	$ —	$ 23
Alpine-funded capital	134	—	—	—	$ —	$ 134
Total	$ 451	$ 53	$ 77	$ 12	$ 19	$ 612

2020 Capital Program

We entered 2020 with an internally funded capital program of $100 million to $300 million, which may be adjusted during the course of the year depending on commodity prices. Additionally, existing JV partners will increase our capital program by approximately $160 million to $200 million for a program total of $260 million to $500 million. We are currently operating seven drilling rigs funded by JV capital and one internally funded drilling rig.

We are focusing our 2020 capital on short payout projects like capital workovers, especially in the first half of the year, as well as primary drilling of vertical and lateral wells and low-risk projects including waterflood and steamflood investments that maintain base production. Early in the year, our capital will be mostly focused on high-VCI short-payout workovers in addition to safety and maintenance-related projects. We may add more drilling projects as the year progresses depending on the overall commodity price environment. Our approach to our 2020 drilling and overall capital program is consistent with our stated strategy to remain financially disciplined and fund projects through either internally generated cash flow or JV capital. We will continue to deploy our partners' capital as part of our Alpine joint venture and opportunistically pursue additional strategic relationships. We will deploy capital to projects that help continue to stabilize our production, develop our long-term resources and return our production to a growth profile. Our current drilling inventory comprises a diversified portfolio of oil and natural gas locations that are economically viable in a variety of operating and commodity price conditions.

We will continue to focus our internally funded capital program on our core areas: Elk Hills, Wilmington, Huntington Beach, Buena Vista, Mount Poso and other appraisal long-term prospects. Our Alpine JV is focused exclusively on Elk Hills.

We plan to invest approximately 40% of our internally funded 2020 capital program in capital workovers of existing well bores. Capital workovers in Elk Hills and other fields are some of the highest VCI projects in our portfolio and generally include well deepenings, recompletions, changes in lift methods and other activities designed to add incremental productive intervals and reserves.

We plan to invest approximately 35% of our capital on the development of conventional and unconventional projects. The depth of our conventional wells is expected to range from 2,000 to 12,000 feet. Our conventional program includes wells located primarily in the Los Angeles basin, Mount Poso and other appraisal long-term prospects primarily focused on waterflood and primary drilling. We also intend to drill unconventional wells mainly in the Buena Vista area. With continued focus on cost savings and efficiencies, many of our deep conventional and unconventional wells have become more competitive.

Further, approximately 20% of our 2020 capital program is intended for facilities development for our newer projects, including pipeline and gathering line interconnections, gas compression and water management systems, and for mechanical integrity and health, safety and environmental projects. About 5% is intended to be used for exploration and other corporate uses.

Efficiency gains in our capital costs have enabled us to maintain a robust capital program even in a low commodity price environment. We will continue to build our inventory of available projects, which will position us to accelerate value by utilizing third-party capital and take advantage of potential future commodity price increases.

Off-Balance-Sheet Arrangements

We have no off-balance-sheet arrangements other than the purchase obligations described in the *Contractual Obligations* section below.

Contractual Obligations

The table below summarizes and cross-references our contractual obligations as of December 31, 2019. This summary indicates on- and off-balance-sheet obligations as of December 31, 2019.

	Payments Due by Year				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
On-Balance Sheet			(in millions)		
Long-term debt[a]	$ 4,977	$ 100	$ 4,733	$ 144	$ —
Interest on long-term debt[b]	988	398	573	17	—
Asset retirement obligations[c]	517	28	—	—	489
Pension and postretirement	183	13	18	18	134
Operating and finance leases[d]	92	33	21	15	23
Other long-term liabilities	6	2	4	—	—
Off-Balance Sheet					
Purchase obligations[e]	153	88	24	19	22
Total	$ 6,916	$ 662	$ 5,373	$ 213	$ 668

(a) In performing the calculation, the 2014 Revolving Credit Facility borrowings outstanding at December 31, 2019 of $518 million were assumed to be outstanding for the entire term of the agreement. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 6 Debt* for more information.

(b) The calculation of cash interest payments on our variable interest-rate debt assumes the interest rate at December 31, 2019 will continue for the entire term and no settlement payments will be received under our interest-rate cap agreements.

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

(d) Our operating leases include drilling rigs, commercial office space, fleet vehicles and certain facilities. Our finance leases include information technology equipment and are not material to our consolidated financial statements taken as a whole.

(e) Amounts include payments that will become due under long-term agreements to purchase goods and services used in the normal course of business primarily including pipeline capacity and land easements. Purchase obligations for pipeline capacity are based on contractual volumes and our internal estimate of future prices during the contract period. Land easements include obligations for fixed payments under our term contracts, and those held by production cannot be reliably estimated.

Lawsuits, Claims, Commitments and Contingencies

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

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2019 and 2018 were not material to our consolidated 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 would not be material to our consolidated financial position or results of operations.

See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Lawsuits, Claims, Commitments and Contingencies*.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates include property, plant and equipment and fair value measurements. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 1 Nature of Business, Summary of Significant Accounting Policies and Other* for details on these critical accounting policies and estimates that involve management's judgment and that could result in a material impact to the consolidated financial statements due to the levels of subjectivity and judgment.

Significant Accounting and Disclosure Changes

See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Accounting and Disclosure Changes* for a discussion of new accounting standards.

FORWARD-LOOKING STATEMENTS

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

- financial position, liquidity, cash flows and results of operations
- business prospects
- transactions and projects
- operating costs
- Value Creation Index (VCI) metrics, which are based on certain estimates including future production rates, costs and commodity prices
- operations and operational results including production, hedging and capital investment
- budgets and maintenance capital requirements
- reserves
- type curves
- expected synergies from acquisitions and joint ventures

Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. While we believe assumptions or bases underlying our expectations are reasonable and make them in good faith, they almost always vary from actual results, sometimes materially. We also believe third-party statements we cite are accurate but have not independently verified them and do not warrant their accuracy or completeness. Factors (but not necessarily all the factors) that could cause results to differ include:

- commodity price changes
- debt limitations on our financial flexibility
- insufficient cash flow to fund planned investments, debt repurchases or changes to our capital plan
- inability to enter desirable transactions including acquisitions, asset sales and joint ventures
- legislative or regulatory changes, including those related to drilling, completion, well stimulation, operation, inspection, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products
- joint ventures and acquisitions and our ability to achieve expected synergies
- the recoverability of resources and unexpected geologic conditions
- incorrect estimates of reserves and related future cash flows and the inability to replace reserves
- changes in business strategy
- PSC effects on production and unit production costs
- effect of stock price on costs associated with incentive compensation
- insufficient capital or liquidity, including as a result of lender restrictions, unavailability of capital markets or inability to attract potential investors
- effects of hedging transactions
- equipment, service or labor price inflation or unavailability
- availability or timing of, or conditions imposed on, permits and approvals
- lower-than-expected production, reserves or resources from development projects, joint ventures or acquisitions, or higher-than-expected decline rates
- disruptions due to accidents, mechanical failures, power outages, transportation or storage constraints, natural disasters, pandemics, labor difficulties, cyber attacks or other catastrophic events
- factors discussed in *Part I, Item 1A – Risk Factors.*

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

ITEM 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our financial results are sensitive to fluctuations in oil, NGL and natural gas prices. In 2020, we expect that price changes at current levels of production, excluding the impact of existing hedges discussed below, would affect our pre-tax annual income and cash flows as follows:

Pre-tax 2020 Price Sensitivities		(in millions)
$1 change in Brent index – Oil[a]	$	23.0
$1 change in Brent index – NGLs	$	2.9
$0.10 change in NYMEX – Natural gas[b]	$	2.6

(a) Assumes no hedges.
(b) Amount reflects the sensitivity with respect to unhedged volumes and includes the offsetting effect of gas used in our operations.

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

As of December 31, 2019, we had net assets of $35 million for our derivative commodity positions which are carried at fair value, using industry-standard models with various inputs, including the forward curve for the relevant price index. A 10% increase or decrease in the fair value of our net derivative assets would affect pre-tax earnings by approximately $4 million. See additional hedging information in *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources*.

Our current oil hedge positions provide for the following expected outcomes:

	Q1 2020	**Q2 2020**	**Q3 2020**	**Q4 2020**
Barrels per day	30,000	20,000	13,000	8,000
	Receive Brent if Brent > $71	Receive Brent if Brent > $68	Receive Brent if Brent > $65	Receive Brent if Brent > $65
	Receive $71 if Brent between $57 and $71	Receive $68 if Brent between $54 and $68	Receive $65 if Brent between $54 and $65	Receive $65 if Brent between $53 and $65
	Receive Brent + $14 if Brent < $57	Receive Brent + $14 if Brent < $54	Receive Brent + $11 if Brent < $54	Receive Brent + $12 if Brent < $53
Barrels per day		5,000 [a]	5,000 [b]	5,000 [b]
		Receive $70 Brent at all prices	Receive $65 Brent at all prices except when Brent < $55 then receive Brent + $10	Receive $65 Brent at all prices except when Brent < $55 then receive Brent + $10

(a) Our counterparties have the option to increase volumes by up to an additional 5,000 barrels per day at the same price at a weighted-average Brent price of $70.05
(b) A counterparty has the option to increase volumes by up to an additional 5,000 barrels per day at a weighted-average Brent price of $65.

Counterparty Credit Risk

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

As of December 31, 2019, the substantial majority of the credit exposure related to our derivative financial instruments was with investment grade counterparties. We believe exposure to credit-related losses at December 31, 2019 was not material and losses associated with credit risk have been insignificant for all years presented.

Interest-Rate Risk

As of December 31, 2019, we had borrowings of $1.3 billion outstanding under our 2017 Credit Agreement, $1 billion outstanding under our 2016 Credit Agreement and $518 million outstanding under our 2014 Revolving Credit Facility, all of which carry variable interest rates. A one-eighth percent change in the interest rates on these outstanding borrowings under these facilities would result in an approximately $4 million change in annual interest expense assuming no payments are received under our interest-rate cap agreements described below.

As of December 31, 2019, we had interest-rate caps that limit our interest rate exposure with respect to $1.3 billion of our variable-rate indebtedness. The interest-rate contracts reset monthly and require the counterparties to pay any excess interest owed on such amount in the event the one-month LIBOR exceeds 2.75% for any monthly period prior to May 4, 2021. We have not received any settlement payments under our interest-rate contracts.

The following table shows the face value and fair value of our fixed- and variable-rate debt as of December 31, 2019:

Year of Maturity	U.S. Dollar Fixed-Rate Debt	U.S. Dollar Variable-Rate Debt	Total
		(in millions)	
2020	$ 100	$ —	$ 100
2021	444	1,518	1,962
2022[(a)]	1,471	1,300	2,771
2023	—	—	—
2024	144	—	144
Total	$ 2,159	$ 2,818	$ 4,977
Weighted-average interest rate	7.61%	8.44%	8.08%
Fair value	$ 1,017	$ 2,818	$ 3,835

(a) The $1.3 billion U.S. dollar variable-rate debt is subject to a springing maturity of 91 days prior to the maturity of our 2016 Credit Agreement if more than $100 million in principal of the 2016 Credit Agreement is outstanding at that time.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
California Resources Corporation:

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

We have audited the accompanying consolidated balance sheets of California Resources Corporation and subsidiaries (the Company) as of December 31, 2019 and 2018, the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles (GAAP). Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Change in Accounting Principle

As discussed in Notes 2 and 7 to the consolidated financial statements, the Company has changed its method of accounting for leases as of January 1, 2019 due to the adoption of Accounting Standards Codification Topic 842, *Leases*.

Basis for Opinions

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

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Assessment of estimated oil and gas reserves on depletion expense for proved oil and gas properties.

As discussed in Note 1 to the consolidated financial statements, the Company determines depletion of oil and gas producing properties by the unit-of-production method. Under this method, capitalized costs of producing oil and gas properties, along with support equipment and facilities, are amortized based on proved oil, and gas reserves. For the year ended December 31, 2019, the Company recorded depreciation, depletion and amortization expense of $471 million. Estimating proved oil and gas reserves requires the expertise of professional petroleum reservoir engineers, who take into consideration forecasted production, operating and capital cost assumptions, and commodity prices inclusive of market differentials. The Company's internal technical personnel, such as reservoir engineers and geoscientists, estimate proved oil, NGLs, and natural gas reserves. The Company engages independent reservoir engineering specialists to perform an independent evaluation of a portion of the Company's proved oil and gas reserve estimates.

We identified the assessment of estimated oil and gas reserves on depletion expense for proved oil and gas properties as a critical audit matter. Complex auditor judgment was required in evaluating the Company's estimate of proved oil and gas reserves, which is an input to the determination of depletion expense. Specifically, auditor judgment was required to evaluate the assumptions used by the Company related to forecasted production and operating and capital costs.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's depletion process, including controls over the estimation of proved oil and gas reserves. We evaluated the competence, capabilities, and objectivity of the internal technical personnel who estimated the proved oil and gas reserves and the independent reservoir engineering specialists engaged by the Company. We analyzed and assessed the determination of depletion expense for compliance with industry and regulatory standards. We assessed the methodology used by the Company's internal technical personnel to estimate proved oil and gas reserves and the methodology used by the independent reservoir engineering specialists to evaluate those reserve estimates for compliance with industry and regulatory standards. We compared the forecasted production assumptions used by the Company's internal technical personnel to historical production rates. We evaluated the operating and capital cost assumptions used by the Company's internal technical personnel by comparing them to historical costs. We compared the commodity prices used by the Company's internal technical personnel to publicly available prices and tested the relevant market differentials. We read and considered the reports of the independent reservoir engineering specialists in connection with our evaluation of the Company's reserves estimates.

Assessment of impairment triggering events for proved oil and gas properties

As discussed in Note 1 to the consolidated financial statements, the Company periodically assesses their proved oil and gas properties for triggering events that could indicate impairment. If a triggering event is identified, an undiscounted cash flows analysis would be required to determine the recoverability of those oil and gas properties. The Company analyzes indicators for possible triggers of impairment such as significant other than temporary decreases in commodity prices, significant increases in expected operating and development costs, significant declines in reserves estimates, or significant adverse changes in the legislative or regulatory environments in which the company operates.

We identified the assessment of impairment triggering events for proved oil and gas properties as a critical audit matter. Specifically, complex auditor judgment was required in evaluating the Company’s identification of triggering events for proved oil and gas properties due to the uncertainty associated with future commodity prices, estimated oil and gas reserves, and operating and development costs.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company’s assessment of indicators for possible triggers of impairment, including controls over the evaluation commodity prices, estimated oil and gas reserves, and capital and operating and development costs. We assessed the changes in commodity prices period over period in consideration of the estimated future commodity prices and tested the relevant market differentials. We compared estimated future commodity prices used in the Company’s assessment to publicly available market information. We analyzed the historical operating margins of those oil and gas properties by comparing period over period results. We evaluated the competence, capabilities, and objectivity of the internal technical personnel who estimated the oil and gas reserves and the independent reservoir engineering specialists engaged by the Company. We evaluated the Company’s assessment of the indicators for possible triggers of impairment related to estimated oil and gas reserves by comparing the Company’s forecasted production, operating and development cost assumptions to historical amounts. In addition, to evaluate the Company’s assessment of indicators for possible triggers of impairment, we considered evidence that might be contrary to assumptions used by the Company, including changes in the legislative and regulatory environments, publicly available information, and other relevant information.

/s/ KPMG LLP

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

Los Angeles, California
February 26, 2020

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets
As of December 31, 2019 and 2018
(in millions, except share data)

	2019		2018	
CURRENT ASSETS				
Cash	$	17	$	17
Trade receivables		277		299
Inventories		67		69
Other current assets, net		130		255
Total current assets		491		640
PROPERTY, PLANT AND EQUIPMENT		22,889		22,523
Accumulated depreciation, depletion and amortization		(16,537)		(16,068)
Total property, plant and equipment, net		6,352		6,455
OTHER ASSETS		115		63
TOTAL ASSETS	$	6,958	$	7,158
CURRENT LIABILITIES				
Current maturities of long-term debt		100		—
Accounts payable		296		390
Accrued liabilities		313		217
Total current liabilities		709		607
LONG-TERM DEBT		4,877		5,251
DEFERRED GAIN AND ISSUANCE COSTS, NET		146		216
OTHER LONG-TERM LIABILITIES		720		575
MEZZANINE EQUITY				
Redeemable noncontrolling interests		802		756
EQUITY				
Preferred stock (20 million shares authorized at $0.01 par value); no shares outstanding at December 31, 2019 or 2018		—		—
Common stock (200 million shares authorized at $0.01 par value); 49,175,843 shares outstanding at December 31, 2019, 48,650,420 shares outstanding at December 31, 2018		—		—
Additional paid-in capital		5,004		4,987
Accumulated deficit		(5,370)		(5,342)
Accumulated other comprehensive loss		(23)		(6)
Total equity attributable to common stock		(389)		(361)
Noncontrolling interests		93		114
Total equity		(296)		(247)
TOTAL LIABILITIES AND EQUITY	$	6,958	$	7,158

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations
For the years ended December 31, 2019, 2018 and 2017
(in millions, except per share data)

	2019	2018	2017
REVENUES			
Oil and natural gas sales	$ 2,270	$ 2,590	$ 1,936
Net derivative (loss) gain from commodity contracts	(59)	1	(90)
Other revenue	423	473	160
Total revenues	2,634	3,064	2,006
COSTS			
Production costs	895	912	876
General and administrative expenses	290	299	249
Depreciation, depletion and amortization	471	502	544
Taxes other than on income	157	149	136
Exploration expense	29	34	22
Other expenses, net	363	399	106
Total costs	2,205	2,295	1,933
OPERATING INCOME	429	769	73
NON-OPERATING (LOSS) INCOME			
Interest and debt expense, net	(383)	(379)	(343)
Net gain on early extinguishment of debt	126	57	4
Gain on asset divestitures	—	5	21
Other non-operating expenses	(72)	(23)	(17)
INCOME (LOSS) BEFORE INCOME TAXES	100	429	(262)
Income tax provision	(1)	—	—
NET INCOME (LOSS)	99	429	(262)
NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS			
Mezzanine equity	(117)	(99)	—
Equity	(10)	(2)	(4)
Net income attributable to noncontrolling interests	(127)	(101)	(4)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	$ (28)	$ 328	$ (266)
Net (loss) income attributable to common stock per share			
Basic	$ (0.57)	$ 6.77	$ (6.26)
Diluted	$ (0.57)	$ 6.77	$ (6.26)

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Comprehensive Income
For the years ended December 31, 2019, 2018 and 2017
(in millions)

	2019	2018	2017
Net income (loss)	$ 99	$ 429	$ (262)
Net income attributable to noncontrolling interests	(127)	(101)	(4)
Other comprehensive income (loss) items:			
Reclassification of unrealized gains (losses) on pension and postretirement losses[a]	(24)	13	(14)
Reclassification of realized losses on pension and postretirement to income(a)	7	4	5
Total other comprehensive income (loss)	(17)	17	(9)
Comprehensive (loss) income attributable to common stock	$ (45)	$ 345	$ (275)

(a) No associated tax for 2019, 2018 and 2017. See *Part II, Item 8 Financial Statements and Supplementary Data, Note 14 Pension and Postretirement Benefit Plans* for additional information.

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Equity
For the years ended December 31, 2019, 2018 and 2017
(in millions)

	Additional Paid-in Capital	Accumulated (Deficit) Earnings	Accumulated Other Comprehensive (Loss) Income	Equity Attributable to Common Stock	Equity Attributable to Noncontrolling Interests	Total Equity
Balance, December 31, 2016	$ 4,861	$ (5,404)	$ (14)	$ (557)	$ —	$ (557)
Net (loss) income	—	(266)	—	(266)	4	(262)
Contribution from noncontrolling interest holders, net	—	—	—	—	98	98
Distributions paid to noncontrolling interest holders	—	—	—	—	(8)	(8)
Other comprehensive loss	—	—	(9)	(9)	—	(9)
Share-based compensation, net	18	—	—	18	—	18
Balance, December 31, 2017	$ 4,879	$ (5,670)	$ (23)	$ (814)	$ 94	$ (720)
Net income	—	328	—	328	2	330
Contribution from noncontrolling interest holders, net	—	—	—	—	82	82
Distributions paid to noncontrolling interest holders	—	—	—	—	(64)	(64)
Issuance of common stock[(a)]	101	—	—	101	—	101
Other comprehensive income	—	—	17	17	—	17
Share-based compensation, net	7	—	—	7	—	7
Balance, December 31, 2018	$ 4,987	$ (5,342)	$ (6)	$ (361)	$ 114	$ (247)
Net income	—	(28)	—	(28)	10	(18)
Contribution from noncontrolling interest holders, net	—	—	—	—	49	49
Distributions paid to noncontrolling interest holders	—	—	—	—	(80)	(80)
Other comprehensive income	—	—	(17)	(17)	—	(17)
Warrant	3			3		3
Share-based compensation, net	14	—	—	14	—	14
Balance, December 31, 2019	$ 5,004	$ (5,370)	$ (23)	$ (389)	$ 93	$ (296)

Note: Excludes amounts related to redeemable noncontrolling interests recorded in mezzanine equity. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 5 Joint Ventures* for more information.

(a) Includes 2.85 million shares of common stock (valued at $51 million at issuance) issued to Chevron in connection with our acquisition of Chevron's working interest in the Elk Hills unit and 2.3 million shares of common stock (valued at $50 million at issuance) issued to an Ares-led investor group. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Acquisitions and Divestitures* and *Part II, Item 8 – Financial Statements and Supplementary Data, Note 5 Joint Ventures* for more information.

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows
For the years ended December 31, 2019, 2018 and 2017
(in millions)

	2019	2018	2017
CASH FLOW FROM OPERATING ACTIVITIES			
Net income (loss)	$ 99	$ 429	$ (262)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	471	502	544
Net derivative loss (gain) from commodity contracts	59	(1)	90
Net proceeds (payments) on settled commodity derivatives	111	(228)	(7)
Net gain on early extinguishment of debt	(126)	(57)	(4)
Amortization of deferred gain	(70)	(76)	(74)
Gain on asset divestitures	—	(5)	(21)
Other non-cash charges to income, net	131	97	77
Dry hole expenses	7	16	2
Changes in operating assets and liabilities, net:			
Decrease (increase) in trade receivables	22	(23)	(45)
(Increase) decrease in inventories	—	(6)	2
Increase in other current assets	(1)	(9)	(2)
Decrease in accounts payable and accrued liabilities	(27)	(178)	(52)
Net cash provided by operating activities	676	461	248
CASH FLOW FROM INVESTING ACTIVITIES			
Capital investments	(455)	(690)	(371)
Changes in capital investment accruals	(85)	69	27
Asset divestitures	164	18	33
Acquisitions	(6)	(547)	—
Other	(12)	(6)	(2)
Net cash used in investing activities	(394)	(1,156)	(313)
CASH FLOW FROM FINANCING ACTIVITIES			
Proceeds from 2014 Revolving Credit Facility	2,330	2,823	1,696
Repayments of 2014 Revolving Credit Facility	(2,353)	(2,646)	(2,180)
Proceeds from 2017 Term Loan	—	—	1,274
Payments on 2014 Term Loan	—	—	(650)
Debt repurchases	(156)	(199)	(116)
Debt transaction costs	(2)	(4)	(42)
Contributions from noncontrolling interest holders, net	49	796	98
Distributions paid to noncontrolling interest holders	(151)	(121)	(8)
Issuance of common stock	4	54	3
Shares canceled for taxes	(3)	(11)	(2)
Net cash (used) provided by financing activities	(282)	692	73
(Decrease) increase in cash	—	(3)	8
Cash—beginning of year	17	20	12
Cash—end of year	$ 17	$ 17	$ 20

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

Notes to Consolidated Financial Statements

NOTE 1 NATURE OF BUSINESS, SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND OTHER

Nature of Business

We are an independent oil and natural gas exploration and production company operating properties exclusively within California. We were incorporated in Delaware as a wholly owned subsidiary of Occidental Petroleum Corporation (Occidental) on April 23, 2014, and we became an independent, publicly traded company on December 1, 2014.

Except when the context otherwise requires or where otherwise indicated, all references to ‘‘CRC,’’ the ‘‘Company,’’ ‘‘we,’’ ‘‘us’’ and ‘‘our’’ refer to California Resources Corporation and its subsidiaries.

Basis of Presentation

We have prepared this report in accordance with United States (U.S.) generally accepted accounting principles (U.S. GAAP) and the rules and regulations of the U.S. Securities and Exchange Commission applicable to annual financial information.

All financial information presented consists of our consolidated results of operations, financial position and cash flows. The assets and liabilities in the consolidated financial statements are presented on a historical cost basis. We have eliminated significant intercompany transactions and accounts. We account for our share of oil and natural gas production activities, 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 our consolidated balance sheets, statements of operations and cash flows.

Risks and Uncertainties

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

Concentration of Customers

For the year ended December 31, 2019, our principal customers, Phillips 66 Company and Valero Marketing & Supply Company, each accounted for at least 10%, and collectively accounted for 46%, of our oil and natural gas sales before the effects of hedging. For the year ended December 31, 2018, our principal customers, Phillips 66 Company and Valero Marketing & Supply Company, each accounted for at least 10%, and collectively accounted for 43%, of our oil and natural gas sales before the effects of hedging. For the year ended December 31, 2017, our principal customers, Phillips 66 Company, Andeavor Logistic LP, Valero Marketing & Supply Company and Shell Trading (US) Company, each accounted for at least 10%, and collectively accounted for 67%, of our revenue excluding the impact of derivative gains and losses.

Critical Accounting Policies

Property, Plant and Equipment

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

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

We perform impairment tests with respect to proved properties when product prices decline other than temporarily, reserves estimates change significantly, other significant events occur or management's plans change with respect to these properties in a manner that may impact our ability to realize the recorded asset amounts. Impairment tests incorporate a number of assumptions involving expectations of undiscounted future cash flows, which can change significantly over time. These assumptions include estimates of future product prices, which we base on forward price curves and, when applicable, contractual prices, estimates of oil and natural 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.

Unproved Properties – A portion of the carrying value of our oil and natural gas properties is attributable to unproved properties. At December 31, 2019, the net capitalized costs attributable to unproved properties were approximately $232 million. When we make acquisitions that include unproved properties, we assign values based on estimated reserves that we believe will ultimately be proved. As exploration and development work progresses and if reserves are proved, we transfer the book value from unproved based on the initially determined rate, not based on specific areas, leases or other units. If the exploration and development work were to be unsuccessful, or management decided not to pursue development of these properties as a result of lower commodity prices, higher development and operating costs, contractual conditions or other factors, the capitalized costs of the related properties would be expensed.

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

Depreciation, Depletion and Amortization – We determine depreciation, depletion and amortization (DD&A) of oil and natural gas producing properties by the unit-of-production method. Our unproved reserves are not subject to DD&A until they are classified as proved properties. We amortize acquisition costs over total proved reserves, and capitalized development and successful exploration costs over proved developed reserves. Our gas 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 of up 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 of up to 20 years.

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

Fair Value Measurements

Our assets and liabilities measured at fair value are categorized in a three-level fair-value hierarchy, based on the inputs to the valuation techniques:

Level 1—using quoted prices in active markets for the assets or liabilities;
Level 2—using observable inputs other than quoted prices for the assets or liabilities; and
Level 3—using unobservable inputs.

Transfers between levels, if any, are recognized at the end of each reporting period. We apply the market approach for certain recurring fair value measurements, maximize our use of observable inputs and minimize use of unobservable inputs. We generally use an income approach to measure fair value when observable inputs are unavailable. This approach utilizes management's judgments regarding expectations of projected cash flows using a risk-adjusted discount rate.

Commodity and interest-rate derivatives are carried at fair value. For commodity derivatives, we utilize the mid-point between bid and ask prices for valuing these instruments. For interest-rate derivatives, we utilize the London Interbank Offered Rate (LIBOR) forward curve. 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 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 based on transactions executed in the marketplace. We classify these measurements as Level 2. Commodity derivatives are the most significant items on our consolidated balance sheets affected by recurring fair value measurements.

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

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

Other Accounting Policies

Revenue Recognition

We recognize revenue in accordance with ASC 606, *Revenue from Contracts with Customers*, which is more fully described in *Note 15 Revenue Recognition*.

Inventories

Materials and supplies are valued at weighted-average cost and are reviewed periodically for obsolescence. Finished goods predominantly comprise oil and natural gas liquids (NGLs), which are valued at the lower of cost or market. Inventories as of December 31, 2019 and 2018 consisted of the following:

	2019	2018
	(in millions)	
Materials and supplies	$ 64	$ 65
Finished goods	3	4
Total	$ 67	$ 69

Derivative Instruments

Our derivative contracts are carried at fair value and on a net basis when a legal right of offset exists with the same counterparty. Since we did not apply hedge accounting for any of the periods presented, we recognize any fair value gains or losses on a net basis, over the remaining term of the instrument, in our consolidated statement 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 accounted for as cash-flow or fair-value hedges.

Stock-Based Incentive Plans

We have stockholder-approved stock-based incentive plans for certain executives, employees and non-employee directors that are more fully described in *Note 11 Stock Compensation*.

Earnings Per Share

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

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

Asset Retirement Obligations

We recognize the fair value of asset retirement obligations (ARO) 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 fair value of the retirement obligation is estimated based on future retirement cost estimates and incorporates many assumptions such as time of abandonment, current regulatory requirements, 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 property, plant and equipment (PP&E) balances. If the estimated future cost or timing of cash flow changes, we record an adjustment to both the ARO and PP&E. Over time, the liability is increased and expense is recognized for accretion, and the capitalized cost is recovered over either the useful life of our facilities or the unit-of-production method for our minerals.

At certain of our facilities, we have identified ARO 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 would perform the ARO work and, therefore, we cannot reasonably estimate the fair value of these liabilities. We will recognize ARO in the periods in which sufficient information becomes available to reasonably estimate their fair values. Additionally, for certain plants, we do not have a legal obligation to decommission them and, accordingly, we have not recorded a liability.

The following table summarizes the activity of our ARO, of which $489 million and $402 million are included in other long-term liabilities, with the remaining portion in accrued liabilities at December 31, 2019 and 2018, respectively.

	For the years ended December 31,	
	2019	2018
	(in millions)	
Beginning balance	$ 433	$ 422
Liabilities incurred, capitalized to PP&E	(5)	4
Liabilities settled and paid	(26)	(15)
Accretion expense	36	27
Acquisitions, capitalized to PP&E[a]	—	8
Dispositions, reduction to PP&E	(10)	(1)
Other	4	(1)
Revisions	85	(11)
Ending balance	$ 517	$ 433

(a) For the year ended December 31, 2018, amount includes $7 million related to the Elk Hills transaction and $1 million related to other acquisitions.

The timing of our cash flows and additional testing costs associated with our future asset retirement activities were adjusted in 2019 due to new idle well regulations enacted in the first quarter. These new regulations require operators to either (1) submit annual idle well management plans describing how they will plug and abandon or reactivate a specified percentage of long-term idle wells or (2) pay additional annual fees and perform additional testing to retain greater flexibility to return long-term idle wells to service in the future. These regulations provide a six-year implementation period for testing existing idle wells not scheduled for plugging and abandonment. Newly idle wells must be tested within two years after becoming idle and, thereafter, are subject to the same testing schedule for existing idle wells.

Other Loss Contingencies

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

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

Income Taxes

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

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

Production-Sharing Type Contracts

Our share of production and reserves from operations in the Wilmington field is subject to contractual arrangements similar to production-sharing contracts (PSCs) that are in effect through the economic life of the assets. Under such contracts we are obligated to fund all capital and production costs. We record a share of production and reserves to recover a portion of such capital and production costs and an additional share for profit. Our portion of the production represents volumes: (i) to recover our partners’ share of capital and production costs that we incur on their behalf, (ii) for our share of contractually defined base production and (iii) for our share of remaining production thereafter. We generate returns through our defined share of production from (ii) and (iii) above. These contracts do not transfer any right of ownership to us and reserves reported from these arrangements are based on our economic interest as defined in the contracts. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline, assuming comparable capital investment and production costs. However, our net economic benefit is greater when product prices are higher. The contracts represented approximately 15% of our production for the year ended December 31, 2019.

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

Pension and Postretirement Benefit Plans

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

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

Pension plan assets are measured at fair value. Publicly registered mutual funds are valued using quoted market prices in active markets. Commingled funds are valued at the fund units’ net asset value (NAV) provided by the issuer, which represents the quoted price in a non-active market. Guaranteed deposit accounts are valued at the book value provided by the issuer.

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

Cash

Cash at December 31, 2019 and 2018 included approximately \$3 million and \$2 million, respectively, that is restricted under one of our joint venture (JV) agreements.

Other Current Assets

Other current assets, net as of December 31, 2019 and 2018 consisted of the following:

	2019	2018
	(in millions)	
Net amounts due from joint interest partners[a]	70	68
Derivative assets	39	168
Prepaid expenses	19	16
Other	2	3
Other current assets, net	$ 130	$ 255

(a) Included in the 2019 and 2018 net amounts due from joint interest partners are allowances for doubtful accounts of $22 million and $31 million, respectively.

Accrued Liabilities

Accrued liabilities as of December 31, 2019 and 2018 consisted of the following:

	2019	2018
	(in millions)	
Accrued employee-related costs	$ 116	$ 109
Accrued taxes other than on income	57	38
Asset retirement obligation	28	31
Accrued interest	13	15
Lease liability	28	—
Other	71	24
Accrued liabilities	$ 313	$ 217

In the fourth quarter of 2019, we implemented operational efficiencies and an organizational redesign that reduced our workforce to approximately 1,250 employees. We recorded a related charge to other non-operating expenses of $41 million, consisting of $29 million in salary and severance expense and $12 million for other termination benefits. As of December 31, 2019, our remaining associated liability of $19 million was included in accrued employee-related costs.

Supplemental Cash Flow Information

We did not make any significant U.S. federal and state income tax payments in 2019, 2018 or 2017. Interest paid, net of capitalized amounts, totaled approximately $425 million, $433 million and $393 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Non-cash financing activities during 2019 included valuing the first two tranches of a warrant to purchase 0.4 million shares of our common stock (valued at $3 million) issued in connection with a development joint venture. See *Note 12 Equity* for more information. Non-cash financing activities in 2018 included 2.85 million shares of common stock (valued at $51 million) issued in connection with the Elk Hills transaction. See *Note 4 Acquisitions and Divestitures* for more on the Elk Hills transaction.

NOTE 2   ACCOUNTING AND DISCLOSURE CHANGES

Recently Adopted Accounting and Disclosure Changes

We adopted the Financial Accounting Standards Board's new lease accounting rules (ASC 842), as of January 1, 2019, using the modified retrospective approach where the new lease standard is not applied to prior comparative periods, which continue to be presented under accounting standards in effect for those prior periods. Under the modified retrospective approach, we recognized right-of-use (ROU) assets and lease liabilities of $66 million as of the adoption date. The adoption of the new lease accounting rules did not materially impact our consolidated results of operations and had no impact on cash flows or beginning retained earnings. The new lease standard does not affect our liquidity and has no impact on our debt-covenant calculations under our 2014 Revolving Credit Facility, 2016 Credit Agreement and 2017 Credit Agreement. See *Note 7 Leases* for more information.

NOTE 3   PROPERTY, PLANT AND EQUIPMENT

The carrying value of our PP&E represents the cost incurred to acquire or develop the asset, including any ARO and capitalized interest, 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. ARO are capitalized and recovered over the lives of the related assets. No impairment charges were recorded in 2019, 2018 or 2017.

Property, plant and equipment, net as of December 31, 2019 and 2018 consisted of the following:

	2019	2018
	(in millions)	
Proved oil and natural gas properties	$ 21,285	$ 20,882
Unproved oil and natural gas properties[(a)]	1,055	1,103
Facilities and other	549	538
Total property, plant and equipment	22,889	22,523
Accumulated depreciation, depletion and amortization	(16,537)	(16,068)
Total property, plant and equipment, net	$ 6,352	$ 6,455

(a) Includes accumulated valuation allowance for total unproved properties of $823 million and $819 million at December 31, 2019 and 2018, respectively.

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

	2019	2018	2017
		(in millions)	
Balance, beginning of year	$ 5	$ 4	$ 4
Additions to capitalized exploratory well costs	12	19	4
Reclassification to property, plant and equipment	(3)	(2)	(2)
Charged to expense	(7)	(16)	(2)
Balance, end of year	$ 7	$ 5	$ 4

NOTE 4   ACQUISITIONS AND DIVESTITURES

Acquisitions

Elk Hills Transaction

In April 2018, we acquired the remaining working, surface and mineral interests in the approximately 47,000-acre Elk Hills unit from Chevron U.S.A., Inc. (Chevron) (the Elk Hills transaction) for approximately $518 million, including $7 million of liabilities assumed relating to ARO. We accounted for the Elk Hills transaction as a business combination. As of December 31, 2019, we held all of the working, surface and mineral interests in the former Elk Hills unit. The effective date of the transaction was April 1, 2018.

As part of the Elk Hills transaction, Chevron reduced its royalty interest in one of our oil and natural gas properties by half and extended the time frame to invest the remainder of our capital commitment on that property by the end of 2020. As of December 31, 2019, the remaining commitment was approximately $12 million. In addition, the parties mutually agreed to release each other from pending claims with respect to the former Elk Hills unit.

The following table summarizes the total consideration, including customary closing adjustments, and the allocation of the consideration based on the fair value of the assets acquired as of the acquisition date:

	(in millions)
Consideration:	
Cash	$ 460
Common stock issued (2.85 million shares)	51
Liabilities assumed	7
	$ 518
Identifiable assets acquired:	
Proved properties	$ 435
Other property and equipment	77
Materials and supplies	6
	$ 518

The results of operations for the Elk Hills transaction were included in our consolidated financial statements subsequent to the closing date.

Bakersfield Office Building

In April 2018, we also acquired an office building and land in Bakersfield, California for $48 million. For the initial eight months in 2018, a former owner of the building occupied most of the space as a tenant, from which we generated approximately $4 million in rental income. In December 2018, this tenant downsized the space they are leasing through December 2022, with a corresponding reduction in rent. The vacated space not used by us will be available to lease to other tenants to generate additional income. In addition, the unimproved land may be monetized in the future. Approximately $6 million of the purchase price was allocated to the in-place leases in 2018, which is included in other assets and is being amortized into other expenses, net.

Other

In 2019, we had several other acquisitions totaling approximately $6 million. In 2018, we had other upstream acquisitions totaling approximately $39 million, excluding assumed ARO liabilities of $1 million.

Divestitures

Lost Hills Divestiture

In May 2019, we sold 50% of our working interest and transferred operatorship in certain zones within our Lost Hills field, located in the San Joaquin basin, for total consideration in excess of $200 million, consisting of approximately $168 million and a carried 200-well development program to be drilled through 2023 with an estimated value of $35 million (Lost Hills divestiture). We received cash proceeds of $164 million after transaction costs and purchase price adjustments, which were used to pay down our 2014 Revolving Credit Facility. The partial sale of proved property was accounted for as a normal retirement with no gain or loss recognized. The partial sale of unproved property was recorded as a recovery of cost.

Other

In 2018, we divested non-core assets resulting in $18 million of proceeds and a $5 million gain.

NOTE 5 JOINT VENTURES

Noncontrolling Interests

The following table presents the changes in noncontrolling interests for our consolidated JVs (described in greater detail below), which are reported in equity and mezzanine equity on the consolidated balance sheets for the years ended December 31, 2019 and 2018:

	Equity Attributable to Noncontrolling Interests			Mezzanine Equity – Redeemable Noncontrolling Interest
	Ares JV	**BSP JV**	**Total**	**Ares JV**
			(in millions)	
Balance, December 31, 2017	$ —	$ 94	$ 94	$ —
Net (loss) income attributable to noncontrolling interests	(11)	13	2	99
Contributions from noncontrolling interest holders, net	33	49	82	714
Distributions to noncontrolling interest holders	(7)	(57)	(64)	(57)
Balance, December 31, 2018	$ 15	$ 99	$ 114	$ 756
Net (loss) income attributable to noncontrolling interests	(7)	17	10	117
Contributions from noncontrolling interest holders, net	—	49	49	—
Distributions to noncontrolling interest holders	(8)	(72)	(80)	(71)
Balance, December 31, 2019	$ —	$ 93	$ 93	$ 802

<u>Ares Management L.P. (Ares)</u>

In February 2018, we entered into a midstream JV with ECR Corporate Holdings L.P. (ECR), a portfolio company of Ares Management L.P. (Ares). This JV (Ares JV) holds the Elk Hills power plant (a 550-megawatt natural gas fired power plant) and a 200 million cubic foot per day cryogenic gas processing plant. We hold 50% of the Class A common interest and 95.25% of the Class C common interest in the Ares JV. ECR holds 50% of the Class A common interest, 100% of the Class B preferred interest and 4.75% of the Class C common interest. We received $750 million in proceeds upon entering into the Ares JV, before $3 million of transaction costs.

The Class A common and Class B preferred interests held by ECR are reported as redeemable noncontrolling interest in mezzanine equity due to an embedded optional redemption feature. The Class C common interest held by ECR is reported in equity on our consolidated balance sheets.

The Ares JV is required to distribute each month its excess cash flow over its working capital requirements first to the Class B holders and then to the Class C common interests, on a pro-rata basis. The Class B preferred interest has a deferred payment feature whereby a portion of the monthly distributions may be deferred for the first three years to the fourth and fifth year. The deferred amounts accrue an additional return. Distributions to the Class B preferred interest holders are reported as a reduction to mezzanine equity on our consolidated balance sheets.

We can cause the Ares JV to redeem ECR's Class A and Class B interests, in whole, but not in part, at any time by paying $750 million for the Class B interest and $60 million for the Class A interest, plus any previously accrued but unpaid preferred distributions and a make-whole payment if the redemption happens prior to five years from inception. We have the option to extend the redemption period for up to an additional two and one-half years, in which case the interests can be redeemed for $750 million for the Class B interest and $80 million for the Class A interest, plus any previously accrued but unpaid preferred distributions and a make-whole payment if the redemption happens prior to seven and one-half years from inception. If the Ares JV does not exercise its redemption option at the end of the seven and one-half year period, ECR can either sell its Class A and Class B interests or cause the sale or lease of the Ares JV assets.

Our consolidated statements of operations reflect the full operations of our Ares JV, with ECR's share of net income reported in net income attributable to noncontrolling interests.

Additionally, in 2018, an Ares-led investor group purchased approximately 2.3 million shares of our common stock in a private placement for an aggregate purchase price of $50 million.

Benefit Street Partners (BSP)

In February 2017, we entered into a development joint venture with BSP (BSP JV) where BSP will contribute up to $250 million, subject to agreement of the parties, in exchange for a preferred interest in the BSP JV. BSP is entitled to preferential distributions and, if it receives cash distributions equal to a predetermined threshold, the preferred interest is automatically redeemed in full with no additional payment. To date, BSP funded a total of $200 million in four equal tranches, before transaction costs. The funds contributed by BSP were used to develop certain of our oil and natural gas properties.

The BSP JV holds net profits interests (NPI) in existing and future cash flow from certain of our properties and the proceeds from the NPI are used by the BSP JV to (1) pay quarterly minimum distributions to BSP, (2) make distributions to BSP until the predetermined threshold is achieved, and (3) pay for additional development costs within the project area, upon mutual agreement between members.

Our consolidated results reflect the full operations of the BSP JV, with BSP's share of net income being reported in net income attributable to noncontrolling interests on our consolidated statements of operations.

Other

Alpine JV

In July 2019, we entered into a development joint venture with Alpine Energy Capital, LLC (Alpine) to develop portions of our Elk Hills field (Alpine JV). Alpine is a joint venture between subsidiaries of Colony Capital, Inc. (Colony) and Equity Group Investments. Alpine committed to invest $320 million, which may be increased to a total investment of $500 million, subject to the mutual agreement of the parties. The initial commitment is expected to be invested over a period of up to three years in accordance with a 275-well development plan. Alpine will fund 100% of the drilling and completion costs of these wells, in which they will earn a 90% working interest. If Alpine receives an agreed upon return, our working interest in those wells will increase from 10% to 82.5%. Our consolidated financial statements reflect only our working interest share in the productive wells.

In connection with the Alpine JV, Colony received a warrant to purchase up to 1.25 million shares of our common stock at an exercise price of $40 per share. Colony will be entitled to exercise the warrant in tranches as funding milestones are achieved. Each tranche will have a five-year term commencing on the date on which such tranche becomes exercisable. As of December 31, 2019, 200,000 shares of our common stock were exercisable under this warrant. Colony may elect, in its sole discretion, to pay cash or to exercise the warrant on a cashless basis, pursuant to which Colony will not be required to pay cash for shares of our common stock upon exercise of the warrant but will instead receive fewer shares.

MIRA JV

In April 2017, we entered into a development joint venture with Macquarie Infrastructure and Real Assets Inc. (MIRA) to develop certain of our oil and natural gas properties in exchange for a 90% working interest in the related properties (MIRA JV). MIRA funded 100% of the drilling and completion costs of agreed-upon wells in the drilling program. Our 10% working interest increases to 75% if MIRA receives cash distributions equal to a predetermined threshold return. Of the initial agreed-upon capital program of $140 million, $138 million was funded through December 31, 2019. Our consolidated results reflect only our working interest share in the productive wells.

NOTE 6 DEBT

As of December 31, 2019 and 2018, our long-term debt consisted of the following credit agreements, Second Lien Notes and Senior Notes:

	Outstanding Principal		Interest Rate[(a)]	Maturity	Security
	2019	2018			
Credit Agreements	(in millions)				
2014 Revolving Credit Facility	$ 518	$ 540	LIBOR plus 3.25%-4.00% ABR plus 2.25%-3.00%	June 30, 2021	Shared First-Priority Lien
2017 Credit Agreement	1,300	1,300	LIBOR plus 4.75% ABR plus 3.75%	December 31, 2022[(b)]	Shared First-Priority Lien
2016 Credit Agreement	1,000	1,000	LIBOR plus 10.375% ABR plus 9.375%	December 31, 2021	First-Priority Lien
Second Lien Notes					
Second Lien Notes	1,815	2,067	8%	December 15, 2022[(c)]	Second-Priority Lien
Senior Notes					
5% Senior Notes due 2020	100	100	5%	January 15, 2020	Unsecured
5½% Senior Notes due 2021	100	100	5.5%	September 15, 2021	Unsecured
6% Senior Notes due 2024	144	144	6%	November 15, 2024	Unsecured
Total Debt	$ 4,977	$ 5,251			
Less: Current Maturities	(100)	—			
Long-Term Debt	4,877	5,251			

(a) London Interbank Offered Rates (LIBOR) will be phased out after 2021 and replaced with the Secured Overnight Financing Rate within the United States for U.S. dollar-based LIBOR. Our credit agreements contemplate a discontinuation of LIBOR and have an alternate borrowing rate. We do not expect the discontinuation of LIBOR to have a significant impact on our interest expense.

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

(c) The Second Lien Notes require principal repayments of approximately $287 million in June 2021, $57 million in December 2021 and $59 million in June 2022 and $1,412 million in December 2022.

Credit Agreements

2014 Revolving Credit Facility

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

As of December 31, 2019, we had approximately $317 million of available borrowing capacity, before a $150 million month-end minimum liquidity requirement. Our 2014 Revolving Credit Facility also includes a sub-limit of $400 million for the issuance of letters of credit. As of December 31, 2019 and 2018, we had letters of credit of approximately $165 million and $162 million, respectively. These letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters.

Security – The lenders share a first-priority lien on a substantial majority of our assets with the lenders under of 2017 Credit Agreement, excluding the Elk Hills power plant and midstream assets that are part of the Ares JV.

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

Maturity Date – Our 2014 Revolving Credit Facility matures on June 30, 2021.

Amortization Payments – The 2014 Revolving Credit Facility does not include any obligation to make amortization payments.

Borrowing Base – The borrowing base is redetermined each May 1 and November 1 and was most recently reaffirmed at $2.3 billion in November 2019. The borrowing base is based upon a number of factors, including commodity prices and reserves, declines in which could cause our borrowing base to be reduced. Increases in our borrowing base require approval of at least 80% of our lenders while decreases or affirmations require a two-thirds approval, in each case as measured by relative commitment amount. We and the lenders (requiring a request from the lenders holding two-thirds of the commitments) each may request a special redetermination once in any period between three consecutive scheduled redeterminations. We will be permitted to have collateral released when both (i) our credit ratings are at least Baa3 from Moody's and BBB- from S&P, in each case with a stable or better outlook, and (ii) certain permitted liens securing other debt are released.

Financial Covenants – As of December 31, 2019, our financial performance covenants included a monthly minimum liquidity requirement of not less than $150 million and the following:

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

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

Other Covenants – Our 2014 Revolving Credit Facility includes covenants that, among other things, restrict our ability to incur additional indebtedness, grant liens, make asset sales and investments, repay existing indebtedness, make subsidiary distributions and enter into transactions that would result in fundamental changes. We are also restricted from paying cash dividends on our stock. Generally, these covenants include exceptions that allow us to pursue some of these activities in certain circumstances. In addition to these covenants, we must also apply cash on hand in excess of $150 million daily to repay amounts outstanding. Finally, we are also subject to a cross-default provision that causes a default under this facility if certain defaults occur under any of our other credit agreements or bond indentures.

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

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

We are permitted to use the balance of proceeds from non-borrowing base asset sales for general corporate purposes including acquisitions and to repurchase our Second Lien Notes and Senior Notes subject to certain conditions, including pro-forma compliance with our financial performance covenants and that we have minimum liquidity of $300 million following such repurchase.

Events of Default and Change of Control – Our 2014 Revolving Credit Facility provides for certain events of default, including upon a change of control, that entitle our lenders to declare the outstanding loans immediately due and payable, subject to certain limitations and conditions.

Recent Amendments – Our 2014 Revolving Credit Facility was most recently amended in August 2019 to provide us with flexibility in connection with potential royalty transactions.

2017 Credit Agreement

In November 2017, we entered into a $1.3 billion credit agreement with The Bank of New York Mellon Trust Company, N.A., as administrative agent, and certain other lenders (2017 Credit Agreement). The net proceeds were used to pay the $559 million remaining balance of our term loan under our 2014 Revolving Credit Facility (2014 Term Loan), resulting in a loss on the early extinguishment of debt of $8 million, reduce the balance of our 2014 Revolving Credit Facility and pay accrued interest. The proceeds received were net of a $26 million original issue discount and $38 million in transaction costs. As of December 31, 2019, we had a $1.3 billion term loan outstanding under our 2017 Credit Agreement.

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

Maturity Date – The loans mature on December 31, 2022, subject to a springing maturity of 91 days prior to the maturity of our 2016 Credit Agreement if more than $100 million is outstanding at that time. Prepayment more than 90 days prior to maturity is subject to a 2% premium.

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

Events of Default and Change of Control – Our 2017 Credit Agreement provides for certain events of default, including upon a change of control, that entitle our lenders to declare the outstanding loans immediately due and payable, subject to certain limitations and conditions. We are also subject to a cross-default provision that causes a default under this credit agreement if certain defaults occur under any of our other credit agreements or indentures.

2016 Credit Agreement

In August 2016, we entered into a $1 billion credit agreement with The Bank of New York Mellon Trust Company, N.A., as administrative agent, and certain other lenders (2016 Credit Agreement). The net proceeds from the 2016 Credit Agreement were used to (i) prepay $250 million of our 2014 Term Loan and (ii) reduce our 2014 Revolving Credit Facility by $740 million. The proceeds received were net of a $10 million original issue discount. As of December 31, 2019, we had a $1 billion term loan outstanding under our 2016 Credit Agreement.

Security – Our 2016 Credit Agreement is secured by a first-priority lien on a substantial majority of our assets (excluding the Elk Hills power plant and midstream assets that are part of the Ares JV) but is second in collateral recovery to our 2014 Revolving Credit Facility and 2017 Credit Agreement.

Maturity Date – The loans mature on December 31, 2021. Prepayment is subject to a variable make-whole amount prior to the fourth anniversary. Following the fourth anniversary, we may redeem at par.

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

Events of Default and Change of Control – Our 2016 Credit Agreement provides for certain events of default, including upon a change of control, that entitle our lenders to declare the outstanding loans immediately due and payable, subject to certain limitations and conditions. We are also subject to a cross-default provision that causes a default under this credit agreement if certain defaults occur under any of our other credit agreements or indentures.

Second Lien Notes

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

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

Repurchases – In 2019, we repurchased $252 million in face value of our Second Lien Notes for $156 million in cash, resulting in a pre-tax gain of $126 million including the effect of unamortized deferred gain and issuance costs. In 2018, we repurchased $183 million in face value of our Second Lien Notes for $159 million in cash, resulting in a pre-tax gain of $48 million including the effect of unamortized deferred gain and issuance costs.

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

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

Senior Notes

In October 2014, we issued $5 billion in aggregate principal amount of our senior unsecured notes, including $1 billion of 5% notes due January 15, 2020 (2020 Notes), $1.75 billion of 5.5% notes due September 15, 2021 (2021 Notes) and $2.25 billion of 6% notes due November 15, 2024 (2024 Notes and, collectively, Senior Notes). We used the net proceeds from the issuance of our Senior Notes to make a $4.95 billion cash distribution to Occidental in October 2014.

Repurchases – In 2019, we did not repurchase any of our Senior Notes. In 2018, we repurchased $49 million in face value of our 2024 Notes for $40 million in cash, resulting in a pre-tax gain of $9 million including the effect of unamortized deferred issuance costs.

Financial and Other Covenants – The indenture includes covenants that, among other things, limit our ability to grant liens securing borrowed money subject to certain exceptions and restrict our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. The covenants are not, however, directly linked to measures of our financial performance. In addition, if we experience a "change of control triggering event" (as defined in the indenture), we will be required, unless we have exercised our right to redeem our Senior Notes, to offer to purchase our Senior Notes at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest. We are also subject to a cross-default provision that causes a default under this indenture if certain defaults occur under any of our other credit agreements or indentures.

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

Deferred Gain and Issuance Costs

At December 31, 2019 and 2018, net deferred gain and issuance costs consisted of the following:

	2019	2018
	(in millions)	
Deferred gain	$ 211	$ 313
Deferred issuance costs and original issue discounts	(65)	(97)
Net deferred gain and issuance costs	$ 146	$ 216

Other

At December 31, 2019, we were in compliance with all financial and other debt covenants.

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

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

Principal maturities of debt outstanding at December 31, 2019 are as follows:

	As of December 31, 2019
	(in millions)
2020	$ 100
2021	1,962
2022	2,771
2023	—
2024	144
Thereafter	—
Total	$ 4,977

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, 2019 and 2018, including the fair value of the variable-rate portion, was approximately $3.8 billion and $4.5 billion, respectively, compared to a face value of approximately $5.0 billion and $5.3 billion, respectively.

NOTE 7 LEASES

On January 1, 2019, we adopted ASC 842 using the modified retrospective approach that required us to determine our lease balances as of that date. Prior periods continue to be reported under accounting standards in effect for those periods. We elected to carry forward our accounting treatment for land easements on existing agreements. Mineral leases, including oil and natural gas leases, are not included within the scope of ASC 842.

We have long-term operating leases for commercial office space, drilling rigs, fleet vehicles and certain facilities. In considering whether a contract contains a lease, we first considered whether there was an identifiable asset and then considered how and for what purpose the asset would be used over the contract term.

Our lease liability was determined by measuring the present value of the remaining fixed minimum lease payments as of the date of adoption discounted using our incremental borrowing rate (IBR). In determining our IBR, we considered the average cost of borrowing for publicly traded corporate bond yields, which were adjusted to reflect our credit rating, the remaining lease term for each class of our leases and frequency of payments.

We elected to combine lease and non-lease components in determining fixed minimum lease payments for our drilling rigs and commercial office space. If applicable, fixed minimum lease payments were reduced by lease incentives for our commercial buildings and increased by mobilization and demobilization fees related to our drilling rigs. Certain of our lease agreements include options to renew, which we exercise at our sole discretion, and we did not include these options in determining our fixed minimum lease payments over the lease term. Our lease liability does not include options to extend or terminate our leases. Our leases do not include options to purchase the leased property. Lease agreements for our fleet vehicles include residual value guarantees, none of which are recognized in our financial statements until the underlying contingency is resolved.

For all of our asset classes, we elected to keep leases with an initial term of 12 months or less off the balance sheet and have included costs related to these contracts in our short-term lease cost disclosure below. Contracts with terms of one month or less are excluded from our disclosure of short-term lease costs.

For our long-term contracts, variable lease costs were not included in the measurement of our lease balances. Variable lease costs for our drilling rigs included costs to operate, move and repair the rigs. Variable lease costs for certain of our commercial office buildings included utilities and common area maintenance charges. Variable lease costs for our fleet vehicles included other-than-routine maintenance and other various amounts in excess of our fixed minimum rental fee.

Our operating lease costs, including amounts capitalized to PP&E, for the year ended December 31, 2019 were as follows:

		2019
		(in millions)
Operating lease cost	$	52
Short-term lease cost		74
Variable lease cost[(a)]		21
Total operating lease costs	$	147

(a) Includes $19 million related to drilling rigs, which are capitalized to PP&E.

During the second quarter of 2019, we entered into contracts treated as finance leases, which were not material to our consolidated results of operations.

We sublease certain commercial office space to third parties where we are the primary obligor under the head lease. The lease terms on those subleases never extend past the term of the head lease and the subleases contain no extension options or residual value guarantees. Sublease income is recognized based on the contract terms and included as a reduction of operating lease cost under our head lease. For the year ended December 31, 2019, sublease income was not material to our consolidated financial statements.

Cash flows related to our operating leases for the year ended December 31, 2019 were as follows:

		2019
		(in millions)
Operating cash flows	$	14
Investing cash flows	$	40

Our cash flows related to finance leases were not significant for the year ended December 31, 2019.

Other information related to our operating and finance leases as of December 31, 2019 was as follows:

	2019
Operating Leases	
ROU asset obtained in exchange for lease obligations (in millions)	$ 122
Weighted-average remaining lease term (in years)	4.75
Weighted-average discount rate	12.2%
Finance Leases	
ROU asset obtained in exchange for lease obligations (in millions)	$ 2
Weighted-average remaining lease term (in years)	2.33
Weighted-average discount rate	8.5%

The difference in the weighted-average discount rate between operating leases and finance leases primarily relates to lease term.

Balance sheet information related to our operating and finance leases as of December 31, 2019 was as follows:

	Balance Sheet Location	2019
Assets		(in millions)
Operating lease, net	*Other assets*	$ 59
Finance lease, net	*PP&E*	2
Total lease assets		$ 61
Liabilities		
Current		
Operating lease	*Accrued liabilities*	$ 27
Finance lease	*Accrued liabilities*	1
Long-term		
Operating lease	*Other long-term liabilities*	37
Finance lease	*Other long-term liabilities*	1
Total lease liabilities		$ 66

As part of our company-wide consolidation of office space, we vacated certain office space in 2019, some of which we subleased. When we enter into a sublease agreement, we evaluate the carrying value of our ROU asset (including the carrying value of related tenant improvements) for impairment based on future identifiable cash flows. For the year ended December 31, 2019, we recognized impairment charges of $3 million related to our leases and $6 million related to abandoned tenant improvements. We may terminate leases for vacated office space before the expiration of the lease term. In cases where we decided not to sublease vacated commercial office space, we shortened the useful life of the ROU assets and related tenant improvements to recover our remaining costs over our expected period of use. Once the leased office space is vacated, lease costs will be classified as other non-operating expenses on our consolidated statements of operations.

Maturities of our operating and finance lease liabilities at December 31, 2019 are as follows:

	Operating Leases	Finance Leases
	(in millions)	
2020	$ 32	$ 1
2021	11	1
2022	9	—
2023	9	—
2024	6	—
Thereafter	23	—
Less: Interest	(26)	—
Present value of lease liabilities	$ 64	$ 2

We entered into a contract for a facility that is under construction as of December 31, 2019. This lease is not included in our lease population at December 31, 2019 because the lease term has not commenced, and we do not control the asset during construction. We will apply the new lease standard when the asset is placed in service by us, which is expected to be in June 2020.

At December 31, 2018, future minimum lease payments for noncancelable operating leases under ASC 840 (excluding oil and natural gas and other mineral leases, utilities, taxes, insurance and common area maintenance expenses) were:

	December 31, 2018
	(in millions)
2019	$ 12
2020	8
2021	7
2022	7
2023	6
Thereafter	28
Total	$ 68

Rent expense for operating leases under ASC 840 was $11 million in 2018 and $13 million in 2017. Rental income from subleases for the years ended December 31, 2018 and 2017 was not significant.

NOTE 8 LAWSUITS, CLAIMS, COMMITMENTS AND CONTINGENCIES

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

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2019 and 2018 were not material to our consolidated 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 would not be material to our consolidated financial position or results of operations.

We have certain commitments under contracts, including purchase commitments for goods and services used in the normal course of business such as pipeline capacity, land easements and field equipment. At December 31, 2019, total purchase obligations on a discounted basis were as follows:

	December 31, 2019
	(in millions)
2020	$ 88
2021	16
2022	8
2023	14
2024	5
Thereafter	22
Total	153
Less: Interest	(24)
Present value of purchase obligations	$ 129

We remain subject to audit by the Internal Revenue Service for calendar years 2016 through 2018 as well as 2015 through 2018 by the state of California.

NOTE 9 DERIVATIVES

We use a variety of derivative instruments to protect our cash flow, operating margin and capital program from the cyclical nature of commodity prices and interest-rate movements. These derivatives are intended to help us maintain adequate liquidity and improve our ability to comply with the covenants of our Credit Facilities in case of commodity-price deterioration.

Commodity-Price Risk

We did not have any commodity derivatives designated as accounting hedges as of and during the years ended December 31, 2019, 2018 and 2017. As part of our hedging program, we held the following Brent-based crude oil contracts as of December 31, 2019:

	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Purchased Puts:				
Barrels per day	30,000	20,000	13,000	8,000
Weighted-average price per barrel	$ 70.83	$ 67.50	$ 65.00	$ 65.00
Sold Puts:				
Barrels per day	30,000	20,000	18,000	13,000
Weighted-average price per barrel	$ 56.67	$ 53.75	$ 54.31	$ 53.81
Swaps:				
Barrels per day	—	5,000	5,000	5,000
Weighted-average price per barrel	$ —	$ 70.05	$ 65.00	$ 65.00

Our counterparties have an option to increase volumes by up to 5,000 barrels per day for the second quarter of 2020 at a weighted-average Brent price of $70.05. A counterparty has an option to increase volumes by up to 5,000 barrels per day for the second half of 2020 at a weighted-average Brent price of $65.00.

The BSP JV entered into crude oil derivatives that are included in our consolidated results but not in the above table. The hedges entered into by the BSP JV could affect the timing of the reversion of BSP's preferred interest. The BSP JV sold call options for approximately 500 barrels per day at a weighted-average price per barrel of $60.00 per barrel for 2020. The BSP JV purchased put options for approximately 2,000 barrels per day at a weighted-average price per barrel of approximately $50.00 for 2020. The BSP JV also purchased put options for approximately 1,000 barrels per day at a weighted-average price per barrel of approximately $45.00 for 2021. The BSP JV also entered into natural gas swaps for insignificant volumes for periods through May 2021.

The outcomes of the derivative positions are as follows:

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

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

For the years ended December 31, 2019, 2018 and 2017, we recorded a non-cash derivative (loss) gain of approximately $(170) million, $229 million, and $(83) million, respectively, from marking these contracts to market, which were included in net derivative (loss) gain from commodity contracts on our consolidated statements of operations. For the year ended December 31, 2019, we received settlement payments of $111 million. For the years ended December 31, 2018 and 2017, we made settlement payments of $228 million and $7 million, respectively.

Interest-Rate Risk

In May 2018, we entered into derivative contracts that limit our interest rate exposure with respect to $1.3 billion of our variable-rate indebtedness. These interest-rate contracts reset monthly and require the counterparties to pay any excess interest owed on such amount in the event the one-month LIBOR exceeds 2.75% for any monthly period prior to May 4, 2021.

For the years ended December 31, 2019 and 2018, we reported losses on these contracts in other non-operating expenses on our consolidated statements of operations of $4 million and $6 million, respectively. No payments were received in either 2019 or 2018.

Fair Value of Derivatives

Our derivative contracts are measured at fair value using industry-standard models with various inputs, including quoted forward prices, and are classified as Level 2 in the required fair value hierarchy for the periods presented.

Commodity Contracts

The following table presents the fair values (at gross and net) of our outstanding derivatives as of December 31, 2019 and 2018:

December 31, 2019

Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented in the Balance Sheet
Assets:		(in millions)	
Other current assets	$ 49	$ (10)	$ 39
Other assets	1	—	1
Liabilities:			
Accrued liabilities	(15)	10	(5)
Other long-term liabilities	—	—	—
	$ 35	$ —	$ 35

December 31, 2018

Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented in the Balance Sheet
Assets:		(in millions)	
Other current assets	$ 252	$ (84)	$ 168
Other assets	23	(9)	14
Liabilities:			
Accrued liabilities	(87)	84	(3)
Other long-term liabilities	(10)	9	(1)
	$ 178	$ —	$ 178

Interest-Rate Contracts

As of December 31, 2019, and 2018, we reported the fair value of our interest-rate derivatives of zero and $4 million, respectively, in other assets on our consolidated balance sheets.

Counterparty Credit Risk

Our credit risk relates primarily to trade receivables, joint interest receivables and derivative financial instruments. Credit exposure for each customer is monitored for outstanding balances and current activity. 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, 2019, the substantial majority of the credit exposures related to our derivative financial instruments was with investment-grade counterparties. We believe exposure to credit-related losses at December 31, 2019 was not material and losses associated with credit risk have been insignificant for all years presented.

All of our derivative instruments are covered by International Swap Dealers Association Master Agreements with counterparties. At December 31, 2019, and 2018, we had insignificant collateral posted.

NOTE 10 INCOME TAXES

Income Tax Provision (Benefit)

Income (loss) before income taxes, which is all domestic, was $100 million, $429 million and $(262) million for the years ended December 31, 2019, 2018 and 2017, respectively. We did not record a significant income tax provision (benefit) in any of the years ended December 31, 2019, 2018 and 2017.

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

	For the years ended December 31,		
	2019	2018	2017
U.S. federal statutory tax rate	21 %	21 %	(35)%
State income taxes, net	7	6	(6)
Exclusion of tax attributable to noncontrolling interests, net	(35)	(5)	—
Decrease in U.S. federal corporate tax rate	—	—	91
Tax credits, net	(9)	(6)	(19)
Nondeductible compensation, net	3	—	—
Stock-based compensation, net	—	—	1
Change in valuation allowance, net	14	(17)	(33)
Other, net	—	1	1
Effective tax rate	1 %	— %	— %

Our effective tax rate is primarily affected by state taxes, income included in our consolidated results which is taxed to noncontrolling interests, and tax credits including the enhanced oil recovery credit. Our U.S. federal deferred tax assets and liabilities were remeasured due to the reduction of the top corporate tax rate from 35% to 21% under the Tax Cuts and Jobs Act (TCJA) enacted on December 22, 2017. The TCJA also included significant changes to the deduction for executive compensation by public corporations.

Given our income tax position, any item affecting our effective tax rate described above is generally offset by an equal change in the valuation allowance. Our valuation allowance increased $21 million during 2019, $16 million of which was recorded to income tax provision and $5 million was recorded to accumulated other comprehensive income. Our valuation allowance decreased $81 million in 2018, $76 million of which was recorded to income tax provision and $5 million was recorded to accumulated other comprehensive income. Our valuation allowance decreased $74 million in 2017, $78 million of which was recorded as an income tax benefit and $4 million reduced accumulated other comprehensive income.

Under the TCJA, for taxable years beginning in 2018, our deduction for business interest is limited to 30% of our adjusted taxable income. For purposes of this limitation, adjustable taxable income is computed without regard to net business interest expense and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization or depletion. Proposed Treasury Regulations issued in December 2018 provide that depreciation, amortization or depletion expense that is capitalized to inventory is not treated as depreciation, amortization or depletion for the purposes of computing adjustable taxable income. It is reasonably possible that the composition of our deferred tax assets, specifically the amount reported for net operating loss and business interest expense carryforwards, could significantly change when the Internal Revenue Service finalizes and issues regulations. Our carryforwards for business interest expense do not expire.

Deferred Tax Assets and Liabilities

The tax effects of temporary differences resulting in deferred income tax assets and liabilities at December 31, 2019 and 2018 were as follows:

	2019		2018	
	Deferred Tax Assets	Deferred Tax Liabilities	Deferred Tax Assets	Deferred Tax Liabilities
	(in millions)			
Debt	$ 176	$ —	$ 253	$ —
Property, plant and equipment	—	(517)	11	(316)
Postretirement benefit accruals	40	—	27	—
Deferred compensation and benefits	55	—	56	—
Asset retirement obligations	155	—	129	—
Net operating loss and tax credit carryforwards	457	—	314	—
Business interest expense carryforward	194	—	82	—
Investment in partnerships	110	—	93	—
Other	36	(60)	17	(41)
Subtotal	1,223	(577)	982	(357)
Valuation allowance	(646)	—	(625)	—
Total deferred taxes	$ 577	$ (577)	$ 357	$ (357)

Components of accumulated other comprehensive income (loss) (AOCI) are presented net of tax. We use the portfolio approach to clear remaining taxes recorded to AOCI when our pension plans are terminated.

Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit use of existing deferred tax assets. A significant piece of evidence evaluated is a history of operating losses. Such evidence limits our ability to consider other evidence such as projections for growth. As of December 31, 2019, we concluded that we could not realize, on a more-likely-than-not basis, any of our deferred tax assets and there is not sufficient evidence to support the reversal of all or any portion of this allowance. Given our recent and anticipated future earnings trends, we do not believe any of the valuation allowance as of December 31, 2019 will be released within the next 12 months. Changes in assumptions or changes in tax laws and regulations could materially affect the recognized amounts of valuation allowance.

Other

As of December 31, 2019, we had U.S. federal net operating loss carryforwards of approximately $1 billion, which begin to expire in 2037, and tax credit carryforwards of $57 million, which begin to expire in 2037.

As of December 31, 2019, we had California net operating loss carryforwards of approximately $2 billion, which begin to expire in 2026, and $20 million of tax credit carryforwards, which begin to expire in 2037.

Unrecognized Tax Benefits

The following is a reconciliation of unrecognized tax benefits:

	For the years ended December 31,		
	2019	2018	2017
	(in millions)		
Unrecognized tax benefits – January 1	$ 25	$ 25	$ 25
Gross increases – tax positions in prior year	44	—	—
Gross increases – tax positions in current year	32	—	—
Unrecognized tax benefits – December 31	$ 101	$ 25	$ 25

The unrecognized tax benefit is reported against deferred taxes on our consolidated balance sheets. If recognized, the amount of unrecognized tax benefit that would affect our effective tax rate is $25 million.

It is reasonably possible that the amount of unrecognized tax benefit with respect to some of our uncertain tax positions could significantly decrease in the next 12 months.

NOTE 11 STOCK-BASED COMPENSATION

In 2019, our stockholders approved the California Resources Corporation Long-Term Incentive Plan (the Plan), which provides for the issuance of stock, incentive and non-qualified stock options, restricted stock awards, restricted stock units, stock appreciation rights, stock bonuses, performance-based awards and other awards to executives, employees and non-employee directors. The maximum number of authorized shares of our common stock that may be issued pursuant to our long-term incentive plan is 7.3 million shares. As of December 31, 2019, 4.7 million shares were issued or reserved under the Plan and 2.6 million shares were available for future issuance of awards under the Plan. Our incentive compensation program is administered by the Compensation Committee of our Board of Directors.

Shares of our common stock may be withheld by us in satisfaction of tax withholding obligations arising upon the exercise of stock options or the vesting of restricted stock units. Further, shares of our common stock may be withheld by us in payment of the exercise price of employee stock options, which also count against the authorized shares specified above.

We recognized the following compensation expense for stock-based awards for the years ended December 31, 2019, 2018 and 2017 in our consolidated statements of operations:

	2019	2018	2017
		(in millions)	
General and administrative expenses	$ 25	$ 36	$ 23
Production costs	7	9	6
Total stock-based compensation expense	$ 32	$ 45	$ 29

For the years ended December 31, 2019, 2018 and 2017, we did not recognize any income tax benefit related to our stock-based compensation. For the years ended December 31, 2019, 2018 and 2017, we made cash payments of $25 million, $24 million and $6 million for the cash-settled portion of our awards, respectively.

As of December 31, 2019, the unrecognized compensation expense for all our unvested stock-based incentive awards was $26 million, based on the year-end value of our common stock. This expense is expected to be recognized over a weighted-average period of two years.

Restricted Stock

Executives and other employees are granted restricted stock units (RSUs), which are in the form of, or equivalent in value to, actual shares of our common stock. RSUs are service based and, depending on the terms of the awards, are settled in cash or stock at the time of vesting. The awards either vest ratably over three years, with one third of the granted units becoming vested on the day before each anniversary date following the date of grant, or vest entirely at the end of three years. Our RSUs have nonforfeitable dividend rights, and any dividends or dividend equivalents declared during the vesting period are paid as declared.

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

The following summarizes our restricted stock activity for the year ended December 31, 2019:

	Stock-Settled		Cash-Settled
	Number of Units (in thousands)	Weighted-Average Grant-Date Fair Value	Number of Units (in thousands)
Unvested at January 1	819	$ 17.36	2,636
Granted[(a)]	171	$ 21.71	1,511
Vested	(409)	$ 19.20	(1,391)
Forfeited	(27)	$ 13.48	(471)
Unvested at December 31	**554**	**$ 17.54**	**2,285**

Performance Stock

Our performance stock units (PSUs) granted in 2019 and 2018 are restricted stock awards with performance targets. The PSUs granted in 2019 are based 50% on achievement of specified cumulative VCI results and 50% on total stockholder return relative to a selected peer group of companies over a three-year period, with payouts ranging from 0% to 200% of the target award. The awards are paid 50% in stock and 50% in cash up to target. Amounts over target are paid in cash. These awards accrue dividend equivalents as dividends are declared during the vesting period, which are paid upon certification for the number of vested units.

The PSUs granted in 2018 are based 50% on achievement of specified cumulative VCI results and 50% on the change in CRC combined production costs compared to the change in production costs of a selected peer group of companies over a three-year period, with payouts ranging from 0% to 200% of the target award. The awards are paid 60% in stock and 40% in cash up to target. Amounts over target are paid in cash. These awards accrue dividend equivalents as dividends are declared during the vesting period, which are paid upon certification for the number of vested units.

Compensation expense is 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.

The following summarizes our PSU activity for the year ended December 31, 2019:

	Stock-Settled		Cash-Settled
	Number of Awards (in thousands)	Weighted-Average Grant-Date Fair Value	Number of Units (in thousands)
Unvested at January 1	294	$ 18.34	196
Granted	214	$ 21.71	214
Vested	—	$ —	—
Forfeited	(11)	$ 20.19	(9)
Unvested at December 31	**497**	**$ 19.75**	**401**

Stock Options

We grant stock options to certain executives under our long-term incentive plan. The options permit the 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, with the majority of options being granted at 10% above fair market value. The options have terms of seven years and vest ratably over three years, with one third of the granted options becoming exercisable on the day before each anniversary date following the date of grant, subject to certain restrictions including continued employment. No stock options were granted during 2017 and 2016.

Fair value 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 award. Expected life is calculated based on the simplified method and represents the period of time that options granted are expected to be held prior to exercise. For options granted in 2019 and 2018, volatility was based on the average historical volatility of our stock. For options granted in 2015 and 2014, volatility was based on the average volatility of the stocks of a select group of peer companies in the absence of adequate stock price history of our common stock at the time of grant. The risk-free interest rate is the implied yield available on zero-coupon U.S. Treasury notes at the grant date with a remaining term approximating the expected life. The dividend yield is the expected annual dividend yield over the expected life, expressed as a percentage of the stock price on the grant date. Of the required assumptions, the expected life of the stock option award and the expected volatility have the most significant impact on the fair value calculation.

The grant date assumptions used in the Black-Scholes valuation for options granted during 2019, 2018, 2015 and 2014 were as follows:

	2019	2018	2015	2014
Exercise price per share	$ 23.88	$ 20.17	$ 42.00	$ 81.10
Expected life (in years)	4.5	4.5	4.5	4.5
Expected volatility	78.26%	69.85%	44.7%	35.4%
Risk-free interest rate	2.47%	2.63%	1.56%	1.40%
Dividend yield	—%	—%	0.95%	0.50%
Grant-date fair value of stock option awards	$ 12.95	$ 10.02	$ 15.00	$ 19.80

The following table summarizes our option activity during the year ended December 31, 2019:

	Options (in thousands)	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Aggregate Intrinsic Value
Beginning balance, January 1	1,287	$ 62.82	$ 17.22	$ —
Granted	144	$ 23.88	$ 12.95	$ —
Exercised	(1)	$ 20.17	$ 10.02	$ —
Expired or Canceled	(3)	$ 22.28	$ 11.69	$ —
Ending balance, December 31	**1,427**	**$ 59.00**	**$ 16.81**	**$ —**
Exercisable at December 31	**1,174**	**$ 66.91**	**$ 17.92**	**$ —**

Stock Awards

In 2019, we granted approximately 79,000 shares of stock to our non-employee directors as the equity-portion of their 2019 compensation.

Employee Stock Purchase Plan

Effective January 1, 2015, we adopted the stockholder-approved California Resources Corporation 2014 Employee Stock Purchase Plan (ESPP), which was subsequently amended in May 2016 and May 2018. 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 authorized shares of our common stock that may be issued pursuant to the ESPP is 1.5 million shares, subject to adjustment pursuant to the terms of the ESPP. In addition, participants in the ESPP are subject to certain limits on the number of shares that can be purchased in any given year and during any given offering period. As of December 31, 2019, 1.0 million shares were issued under our ESPP and 0.5 million shares were available for future issuance. For the year ended December 31, 2019, we issued approximately 0.2 million shares of common stock in connection with our ESPP.

NOTE 12 EQUITY

In connection with a development joint venture we entered into in July 2019, we issued a warrant to Colony to purchase up to 1.25 million shares of our common stock at an exercise price of $40 per share. Colony may exercise the warrant in tranches as funding milestones are achieved. The value of each tranche is recognized in our consolidated balance sheets when a funding milestone begins and has a five-year term commencing on the date on which such tranche becomes exercisable. Colony may elect, in its sole discretion, to pay cash or to exercise on a cashless basis, pursuant to which Colony will not be required to pay cash for shares of common stock upon exercise of the warrant but will instead receive fewer shares.

We calculated the fair value of the first and second tranche on the grant date using the Black-Scholes pricing model assumptions below:

	First Tranche	Second Tranche
Volatility	85.00%	85.00%
Risk-free interest rate	1.80%	1.80%
Dividend yield	—%	—%
Expected term (in years)	5.19	5.45
Fair value of underlying common stock	$ 7.59	$ 7.84
Number of shares	200,000	200,000
Tranche value (in thousands)	$ 1,518	$ 1,568

Each tranche was initially measured at fair value and will not be subsequently remeasured. Each tranche was classified as additional paid-in-capital in equity on the consolidated balance sheet as of December 31, 2019.

The following is a summary of common stock issuances:

	Common Stock
	(in thousands)
Balance, December 31, 2017	42,902
Issued[(a)]	6,110
Canceled	(362)
Balance, December 31, 2018	48,650
Issued	694
Canceled	(168)
Balance, December 31, 2019	49,176

(a) Includes approximately 2.3 million shares issued in a private placement with an Ares-led investor group. For more on our Ares JV, see *Note 5 Joint Ventures*.

At December 31, 2019 and 2018, we had 200 million authorized shares of common stock and 20 million authorized shares of preferred stock, both with a $0.01 par value per share, and no outstanding shares of preferred stock on either date.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) consisted of pension and post-retirement losses of $23 million and $6 million at December 31, 2019 and 2018, respectively.

NOTE 13 EARNINGS PER SHARE

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

	2019	2018	2017
Basic EPS calculation	(in millions, except per share amounts)		
Net income (loss)	$ 99	$ 429	$ (262)
Less: Net income attributable to noncontrolling interests	(127)	(101)	(4)
Net (loss) income attributable to common stock	(28)	328	(266)
Less: Net income allocated to participating securities	—	(7)	—
Net (loss) income available to common stockholders	$ (28)	$ 321	$ (266)
Weighted-average common shares outstanding	49.0	47.4	42.5
Basic EPS	$ (0.57)	$ 6.77	$ (6.26)
Diluted EPS calculation			
Net income (loss)	$ 99	$ 429	$ (262)
Less: Net income attributable to noncontrolling interests	(127)	(101)	(4)
Net (loss) income attributable to common stock	(28)	328	(266)
Less: Net income allocated to participating securities	—	(7)	—
Net (loss) income available to common stockholders	$ (28)	$ 321	$ (266)
Weighted-average common shares outstanding	49.0	47.4	42.5
Dilutive effect of potentially dilutive securities	$ —	$ —	$ —
Diluted EPS	$ (0.57)	$ 6.77	$ (6.26)
Weighted-average antidilutive shares	3.1	1.6	2.3

NOTE 14 PENSION AND POSTRETIREMENT BENEFIT PLANS

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

Defined Contribution Plans

All of our employees are eligible to participate in our tax-qualified, defined contribution retirement plan that provides for periodic cash contributions by us based on annual cash compensation and employee deferrals.

Certain salaried employees participate in supplemental plans that restore benefits lost due to government limitations on qualified plans. As of December 31, 2019 and 2018, we recognized $37 million and $36 million in other long-term liabilities for these supplemental plans, respectively.

We expensed $36 million in 2019, $35 million in 2018 and $33 million in 2017 under the provisions of these defined contribution and supplemental plans.

Defined Benefit Plans

Participation in defined benefit pension plans sponsored by us is limited. During 2019, approximately 70 employees accrued benefits under these plans, all of whom were union employees. Effective December 31, 2015, the plans were amended such that participants other than union employees no longer earn benefits for service after December 31, 2015.

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

Postretirement Benefit Plans

We provide postretirement medical and dental benefits for our eligible former employees and their dependents. Our former employees are required to make monthly contributions to the plan, but the benefits are primarily funded by us as claims are paid during the year.

Obligations and Funded Status of our Defined Benefit Plans

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

	As of December 31,			
	2019	**2018**	**2019**	**2018**
	Pension Benefits		Postretirement Benefits	
Amounts recognized in the balance sheet:	(in millions)			
Accrued liabilities	$ —	$ —	$ (3)	$ (2)
Other long-term liabilities	(18)	(14)	(113)	(82)
	$ (18)	$ (14)	$ (116)	$ (84)
Amounts recognized in accumulated other comprehensive (loss) income:	$ (6)	$ (10)	$ (17)	$ 4

	As of December 31,			
	2019	**2018**	**2019**	**2018**
	Pension Benefits		Postretirement Benefits	
Changes in the benefit obligation:	(in millions)			
Benefit obligation—beginning of year	$ 56	$ 65	$ 84	$ 93
Service cost—benefits earned during the period	1	1	4	4
Interest cost on projected benefit obligation	2	2	4	4
Actuarial loss (gain)	11	(2)	19	(14)
Cost of special termination benefits	—	—	6	—
Curtailment	—	—	2	—
Benefits paid	(25)	(10)	(3)	(3)
Benefit obligation—end of year	$ 45	$ 56	$ 116	$ 84
Changes in plan assets:				
Fair value of plan assets—beginning of year	$ 42	$ 46	$ —	$ —
Actual gain (loss) on plan assets	7	(2)	—	—
Employer contributions	3	8	3	3
Benefits paid	(25)	(10)	(3)	(3)
Fair value of plan assets—end of year	$ 27	$ 42	$ —	$ —
Unfunded status	$ (18)	$ (14)	$ (116)	$ (84)

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

	2019	**2018**
	(in millions)	
Projected Benefit Obligation	$ 45	$ 56
Accumulated Benefit Obligation	$ 41	$ 53
Fair Value of Plan Assets	$ 27	$ 42

None of our defined benefit pension plans had plan assets in excess of accumulated benefit obligations.

Components of Net Periodic Benefit Cost

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

	For the years ended December 31,					
	2019	**2018**	**2017**	**2019**	**2018**	**2017**
	Pension Benefits			Postretirement Benefits		
Net periodic benefit costs:	(in millions)					
Service cost—benefits earned during the period	$ 1	$ 1	$ 1	$ 4	$ 4	$ 3
Interest cost on projected benefit obligation	2	2	2	4	4	4
Expected return on plan assets	(2)	(3)	(3)	—	—	—
Cost of special termination benefits	—	—	—	6	—	—
Amortization of net actuarial loss	1	2	2	—	—	—
Settlement costs	9	4	5	—	—	—
Net periodic benefit cost	$ 11	$ 6	$ 7	$ 14	$ 8	$ 7

	For the years ended December 31,					
	2019	**2018**	**2017**	**2019**	**2018**	**2017**
Amounts recognized in other comprehensive income (loss):	Pension Benefits			Postretirement Benefits		
	(in millions)					
Net actuarial (loss) gain	$ (6)	$ (3)	$ (4)	$ (19)	$ 14	$ (12)
Settlement costs	9	4	5	(2)	—	—
Amortization of net actuarial gain/loss	1	2	2	—	—	—
Total recognized in other comprehensive income (loss)	$ 4	$ 3	$ 3	$ (21)	$ 14	$ (12)

Settlement costs related to our pension plans were associated with early retirements.

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

	For the years ended December 31,			
	2019	**2018**	**2019**	**2018**
Benefit Obligation Assumptions:	Pension Benefits		Postretirement Benefits	
Discount rate	3.16%	4.22%	3.48%	4.57%
Rate of compensation increase	4.00%	4.00%	—	—
Net Periodic Benefit Cost Assumptions:				
Discount rate	4.22%	3.53%	4.57%	3.87%
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 AA Above Median yield curve in both 2019 and 2018. 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 2019, we adopted the Society of Actuaries Pri-2012 mortality assumptions reflecting the MP-2019 Mortality Improvement Scale, which plan sponsors in the U.S. use in the actuarial valuations that determine a plan sponsor’s pension and postretirement obligations. In 2018, we utilized the Society of Actuaries Adjusted RP-2014 Mortality Table reflecting the MP-2018 Mortality Improvement Scale. At December 31, 2019, the changes in the mortality assumptions did not significantly change the pension benefit obligations or the postretirement benefit obligations.

The postretirement benefit obligation was determined by application of the terms of medical and dental benefits, including the effect of established maximums on covered costs, together with relevant actuarial assumptions and healthcare cost trend rates projected at an assumed U.S. Consumer Price Index (CPI) increase of 1.86% and 1.78% as of December 31, 2019 and 2018, 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, as of December 31, 2019, health care cost trend rates would decrease 0.25% per year from 6.50% in 2020 until they reach 4.50% in 2028 and remain at 4.50% thereafter.

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

Fair Value of Pension Plan Assets

We employ a total return investment approach that uses a diversified blend of equity and fixed-income investments to optimize the long-term return of plan assets at a prudent level of risk. Equity investments were diversified across U.S. and non-U.S. stocks, as well as differing styles and market capitalizations. Other asset classes, such as private equity and real estate, may have been used with the goals of enhancing long-term returns and improving portfolio diversification. In 2019 and 2018, the target allocation of plan assets was 65% equity securities and 35% debt securities. Investment performance was measured and monitored on an ongoing basis through quarterly investment portfolio and manager guideline compliance reviews, annual liability measurements and periodic studies.

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

	Fair Value Measurements at December 31, 2019			
	Level 1	**Level 2**	**Level 3**	**Total**
Asset Class:	(in millions)			
Cash equivalents	$ —	$ —	$ —	$ —
Commingled funds:				
Fixed income	—	3	—	3
U.S. equity	—	4	—	4
International equity	—	2	—	2
Mutual funds:				
Bond funds	5	—	—	5
Blend funds	2	—	—	2
Value funds	2	—	—	2
Growth funds	2	—	—	2
Guaranteed deposit account	—	—	7	7
Total pension plan assets	$ 11	$ 9	$ 7	$ 27

	Fair Value Measurements at December 31, 2018			
	Level 1	Level 2	Level 3	Total
Asset Class:	(in millions)			
Cash equivalents	$ 1	$ —	$ —	$ 1
Commingled funds:				
Fixed income	—	9	—	9
U.S. equity	—	9	—	9
International equity	—	5	—	5
Mutual funds:				
Bond funds	5	—	—	5
Blend funds	2	—	—	2
Value funds	2	—	—	2
Growth funds	2	—	—	2
Guaranteed deposit account	—	—	7	7
Total pension plan assets	$ 12	$ 23	$ 7	$ 42

The activity during the years ended December 31, 2019 and 2018, for the assets using Level 3 fair value measurements was insignificant.

Expected Cash Flows

In 2020, we expect to contribute $4 million to our postretirement benefit plans and at least our minimum funding requirement of $2 million to our defined benefit pension plans. Estimated future undiscounted benefit payments, which reflect expected future service, as appropriate, are as follows:

	Pension Benefits	Postretirement Benefits
For the years ended December 31,	(in millions)	
2020	$ 10	$ 4
2021	$ 4	$ 5
2022	$ 2	$ 5
2023	$ 3	$ 5
2024	$ 2	$ 5
2025 - 2029	$ 11	$ 27

NOTE 15 REVENUE RECOGNITION

We account for revenue in accordance with ASC 606, *Revenue from Contracts with Customers*, which we adopted on January 1, 2018 using the modified retrospective method, which was applied to all contracts that were not completed as of that date. Prior period results were not adjusted and continue to be reported under the accounting standards in effect for the applicable period. The new standard did not affect the timing of our revenue recognition and did not impact net income; accordingly, we did not record an adjustment to the opening balance of retained earnings.

We derive substantially all of our revenue from sales of oil, natural gas and NGLs, with the remaining revenue generated from sales of electricity and marketing activities related to storage and managing excess pipeline capacity.

The following is a description of our principal activities from which we generate revenue. Revenues are recognized when control of promised goods is transferred to our customers, in an amount that reflects the consideration we expect to receive in exchange for those goods.

Commodity Sales Contracts

We recognize revenue from the sale of our oil, natural gas and NGL production when delivery has occurred and control passes to the customer. Our commodity contracts are short term, typically less than a year. We consider our performance obligations to be satisfied upon transfer of control of the commodity. In certain instances, transportation and processing fees are incurred by us prior to control being transferred to customers. These costs were previously offset against oil and natural gas sales. Upon adoption of ASC 606, we are recording these costs as a component of other expenses, net on our consolidated statements of operations.

Our commodity sales contracts are based on index prices. We recognize revenue in the amount that we expect to receive once we are able to adequately estimate the consideration (i.e., when market prices are known). Our contracts with customers typically require payment within 30 days following invoicing.

Electricity

The electrical output of the Elk Hills power plant that is not used in our operations is sold to the wholesale power market and to a utility under power purchase and sales agreements (PPAs) through December 2023, which include a monthly capacity payment plus a variable payment based on the quantity of power purchased each month. Revenue is recognized when obligations under the terms of a contract with our customer are satisfied; generally, this occurs upon delivery of the electricity. We report electricity sales as other revenue on our consolidated statements of operations. Revenue is measured as the amount of consideration we expect to receive based on average index or California Independent System Operator market pricing with payment due the month following delivery. Payments under our PPAs are settled monthly. We consider our performance obligations to be satisfied upon delivery of electricity or as the contracted amount of energy is made available to the customer in the case of capacity payments.

Marketing, Trading and Other

Marketing, trading and other revenue primarily includes our activities associated with storing, transporting and marketing our production as well as third-party volumes.

To transport our natural gas as well as third-party volumes, we have entered into firm pipeline commitments. In addition, we may from time-to-time enter into natural gas purchase and sale agreements with third parties to take advantage of market dislocations. We consider our performance obligations to be satisfied upon transfer of control of the commodity.

We report our trading activities on a gross basis with purchases and costs reported in other expenses, net and sales recorded in other revenue on our consolidated statements of operations.

Disaggregation of Revenue

The following table provides disaggregated revenue for the years ended December 31, 2019, 2018 and 2017:

	2019	2018	2017
		(in millions)	
Oil and natural gas sales:			
Oil	$ 1,884	$ 2,110	$ 1,549
NGLs	179	260	210
Natural gas	207	220	177
	2,270	2,590	1,936
Other revenue:			
Electricity	112	111	125
Marketing, trading and other	311	361	35
Interest income	—	1	—
	423	473	160
Net derivative (loss) gain from commodity contracts	(59)	1	(90)
Total revenues	$ 2,634	$ 3,064	$ 2,006

NOTE 16 CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Our Credit Facilities, Second Lien Notes and Senior Notes are guaranteed both fully and unconditionally and jointly and severally by our material wholly owned subsidiaries (Guarantor Subsidiaries). Certain of our subsidiaries do not guarantee our Credit Facilities, Second Lien Notes and Senior Notes (Non-Guarantor Subsidiaries) either because they hold assets that are less than 1% of our total consolidated assets or because they are not considered a "subsidiary" under the applicable financing agreement. The following condensed consolidating balance sheets as of December 31, 2019 and December 31, 2018 and the condensed consolidating statements of operations and statements of cash flows for the years ended December 31, 2019 and 2018, as applicable, reflect the condensed consolidating financial information of our parent company, CRC (Parent), our combined Guarantor Subsidiaries, our combined Non-Guarantor Subsidiaries and the elimination entries necessary to arrive at the information for the Company on a consolidated basis.

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

Condensed Consolidating Balance Sheets
As of December 31, 2019 and 2018
(in millions)

	As of December 31, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total current assets	$ 8	$ 436	$ 60	$ (13)	$ 491
Investments in consolidated subsidiaries	5,956	223	—	(6,179)	—
Total property, plant and equipment, net	35	5,846	471	—	6,352
Other assets	1	82	32	—	115
TOTAL ASSETS	$ 6,000	$ 6,587	$ 563	$ (6,192)	$ 6,958
Total current liabilities	248	469	5	(13)	709
Long-term debt	4,877	—	—	—	4,877
Deferred gain and issuance costs, net	146	—	—	—	146
Other long-term liabilities	167	549	4	—	720
Amounts due to (from) affiliates	951	(953)	2	—	—
Mezzanine equity	—	—	802	—	802
Total equity	(389)	6,522	(250)	(6,179)	(296)
TOTAL LIABILITIES AND EQUITY	$ 6,000	$ 6,587	$ 563	$ (6,192)	$ 6,958

	As of December 31, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total current assets	$ 7	$ 590	$ 56	$ (13)	$ 640
Investments in consolidated subsidiaries	5,440	96	—	(5,536)	—
Total property, plant and equipment, net	23	5,913	519	—	6,455
Other assets	4	32	27	—	63
TOTAL ASSETS	$ 5,474	$ 6,631	$ 602	$ (5,549)	$ 7,158
Total current liabilities	143	465	12	(13)	607
Long-term debt	5,251	—	—	—	5,251
Deferred gain and issuance costs, net	216	—	—	—	216
Other long-term liabilities	140	431	4	—	575
Amounts due to (from) affiliates	85	(86)	1	—	—
Mezzanine equity	—	—	756	—	756
Total equity	(361)	5,821	(171)	(5,536)	(247)
TOTAL LIABILITIES AND EQUITY	$ 5,474	$ 6,631	$ 602	$ (5,549)	$ 7,158

Condensed Consolidating Statements of Operations

For the years ended December 31, 2019, 2018 and 2017

(in millions)

	For the year ended December 31, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ —	$ 2,445	$ 482	$ (293)	$ 2,634
Total costs	186	2,064	248	(293)	2,205
Non-operating (loss) income	(332)	3	—	—	(329)
Income tax provision	(1)				(1)
NET (LOSS) INCOME	(519)	384	234	—	99
Net income attributable to noncontrolling interest	—	—	(127)	—	(127)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	$ (519)	$ 384	$ 107	$ —	$ (28)

	For the year ended December 31, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ 1	$ 2,897	$ 427	$ (261)	$ 3,064
Total costs	207	2,128	221	(261)	2,295
Non-operating (loss) income	(348)	8	—	—	(340)
NET (LOSS) INCOME	(554)	777	206	—	429
Net income attributable to noncontrolling interest	—	—	(101)	—	(101)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	$ (554)	$ 777	$ 105	$ —	$ 328

	For the year ended December 31, 2017				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ 42	$ 1,947	$ 17	$ —	$ 2,006
Total costs	226	1,694	13	—	1,933
Non-operating (loss) income	(353)	18	—	—	(335)
NET (LOSS) INCOME	(537)	271	4	—	(262)
Net income attributable to noncontrolling interest	—	—	(4)	—	(4)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	$ (537)	$ 271	$ —	$ —	$ (266)

Condensed Consolidating Statements of Cash Flows
For the years ended December 31, 2019, 2018 and 2017

(in millions)

	For the year ended December 31, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash (used) provided by operating activities	$ (673)	$ 1,082	$ 267	$ —	$ 676
Net cash used in investing activities	(15)	(378)	(1)	—	(394)
Net cash provided (used) by financing activities	688	(705)	(265)	—	(282)
Decrease (increase) in cash	—	(1)	1	—	—
Cash—beginning of period	—	7	10	—	17
Cash—end of period	$ —	$ 6	$ 11	$ —	$ 17

	For the year ended December 31, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash (used) provided by operating activities	$ (633)	$ 1,374	$ (280)	$ —	$ 461
Net cash used in investing activities	(8)	(1,138)	(10)	—	(1,156)
Net cash provided (used) by financing activities	634	(237)	295	—	692
(Decrease) increase in cash	(7)	(1)	5	—	(3)
Cash—beginning of period	7	8	5	—	20
Cash—end of period	$ —	$ 7	$ 10	$ —	$ 17

	For the year ended December 31, 2017				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash (used) provided by operating activities	$ (481)	$ 718	$ 11	$ —	$ 248
Net cash used in investing activities	(4)	(212)	(97)	—	(313)
Net cash provided (used) by financing activities	492	(510)	91	—	73
Increase (decrease) in cash	7	(4)	5	—	8
Cash—beginning of period	—	12	—	—	12
Cash—end of period	$ 7	$ 8	$ 5	$ —	$ 20

NOTE 17 SUBSEQUENT EVENT

On February 20, 2020, we launched offers to exchange a significant portion of our Second Lien Notes and senior notes into (1) notes and equity interests issued by a non-consolidated entity that will hold a term royalty interest in our Elk Hills unit and/or (2) a new first-lien last-out term loan issued by us and warrants convertible into our common stock. The transaction is expected to close on March 20, 2020.

Quarterly Financial Data (Unaudited)

	2019				2018			
	First	Second	Third	Fourth	First	Second	Third	Fourth
	(in millions, except per share amounts)							
Revenues(a)	$ 690	$ 653	$ 681	$ 610	$ 609	$ 549	$ 828	$ 1,078
Operating income (loss)(b)	$ 57	$ 122	$ 148	$ 102	$ 108	$ 11	$ 185	$ 465
Net (loss) income attributable to common stock(c)	$ (67)	$ 12	$ 94	$ (67)	$ (2)	$ (82)	$ 66	$ 346
Net (loss) income attributable to common stock per share:								
Basic	$ (1.38)	$ 0.25	$ 1.89	$ (1.36)	$ (0.05)	$ (1.70)	$ 1.34	$ 7.00
Diluted	$ (1.38)	$ 0.24	$ 1.89	$ (1.36)	$ (0.05)	$ (1.70)	$ 1.32	$ 7.00

(a) We adopted the new revenue recognition standard on January 1, 2018 which required certain sales-related costs to be reported as expense as opposed to being netted against revenue. The adoption of this standard did not affect net income. Results for reporting periods beginning January 1, 2018 are presented under the new accounting standard while prior periods were not adjusted and continue to be reported under accounting standards in effect for the applicable period.

(b) Net (loss) income attributable to common stock included the following unusual, out-of-period, infrequent and other items:

	2019				2018			
	First	Second	Third	Fourth	First	Second	Third	Fourth
	(in millions)							
Non-cash derivative loss (gain) from commodities, excluding noncontrolling interest	$ 97	$ (4)	$ 6	$ 67	$ 7	$ 92	$ (28)	$ (295)
Non-cash derivative loss from interest-rate contracts	$ 3	$ 1	$ —	$ —	$ —	$ 1	$ (1)	$ 6
Severance and termination benefits	$ —	$ 2	$ —	$ 45	$ 2	$ 2	$ —	$ —
Net gain on early extinguishment of debt	$ (6)	$ (20)	$ (82)	$ (18)	$ —	$ (24)	$ (2)	$ (31)
Gain on asset divestitures	$ —	$ —	$ —	$ —	$ —	$ (1)	$ (3)	$ (1)
Other, net	$ 4	$ (4)	$ (1)	$ 9	$ 1	$ (2)	$ 9	$ 1

Supplemental Oil and Gas Information (Unaudited)

The following table sets forth our net operating and non-operating interests in quantities of proved developed and undeveloped reserves of oil (including condensate), NGLs and natural gas and changes in such quantities. Estimated reserves include our economic interests under PSC-type contracts relating to our Wilmington field in Long Beach. All of our proved reserves are located within the state of California.

PROVED DEVELOPED AND UNDEVELOPED RESERVES

	Oil[a]	NGLs	Natural Gas	Total[b]
	(MMBbl)	(MMBbl)	(Bcf)	(MMBoe)
Balance at December 31, 2016	409	55	626	568
Revisions of previous estimates[c]	47	7	104	71
Improved recovery	—	—	—	—
Extensions and discoveries	24	2	45	34
Divestitures	(8)	—	(3)	(8)
Production	(30)	(6)	(66)	(47)
Balance at December 31, 2017	442	58	706	618
Revisions of previous estimates[c]	51	(4)	(15)	44
Improved recovery	4	—	—	4
Extensions and discoveries	25	1	27	30
Acquisitions	38	11	89	64
Production	(30)	(6)	(73)	(48)
Balance at December 31, 2018	530	60	734	712
Revisions of previous estimates[c]	(34)	(4)	(52)	(47)
Improved recovery	3	—	—	3
Extensions and discoveries	24	2	41	33
Divestitures	(11)	—	6	(10)
Production	(29)	(6)	(75)	(47)
Balance at December 31, 2019	483	52	654	644
PROVED DEVELOPED RESERVES				
December 31, 2016	279	44	500	406
December 31, 2017	304	45	543	440
December 31, 2018	389	47	565	530
December 31, 2019[d]	357	45	543	493
PROVED UNDEVELOPED RESERVES				
December 31, 2016	130	11	126	162
December 31, 2017	138	13	163	178
December 31, 2018	141	13	169	182
December 31, 2019	126	7	111	151

(a) Includes proved reserves related to economic arrangements similar to PSCs of 125 MMBbl, 131 MMBbl, 108 MMBbl and 85 MMBbl at December 31, 2019, 2018, 2017 and 2016, respectively.

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

(c) Commodity price changes affect the proved reserves we record. For example, higher prices generally increase the economically recoverable reserves in all of our operations, because the extra margin extends their expected lives and renders more projects economic. Partially offsetting this effect, higher prices decrease our share of proved cost recovery reserves under arrangements similar to production-sharing contracts at our Wilmington field in Long Beach because fewer reserves are required to recover costs. Conversely, when prices drop, we experience the opposite effects. Performance-related revisions can include upward or downward changes to previous proved reserves estimates due to the evaluation or interpretation of recent geologic, production decline or operating performance data.

(d) Approximately 24% of proved developed oil reserves, 11% of proved developed NGLs reserves, 13% of proved developed natural gas reserves and, overall, 21% of total proved developed reserves are non-producing. A majority of our non-producing reserves relate to steamfloods and waterfloods where full peak production response has not yet occurred due to the nature of such projects.

2019

Revisions of previous estimates – We had negative price-related revisions of 20 MMBoe primarily resulting from a lower commodity-price environment in 2019 compared to 2018.

We had 16 MMBoe of net positive performance-related revisions. We added 23 MMBoe primarily related to better-than-expected performance in the San Joaquin and Los Angeles basins and 18 MMBoe that had been previously removed due to budgeting and development timing. These volumes were brought back into our reserves based on re-evaluation of the applicable areas and management's plans. These positive revisions were partially offset by 25 MMBoe in negative performance-related revisions primarily related to delayed responses in certain waterflood and steamflood projects.

We removed 43 MMBoe of PUD reserves, of which 19 MMBoe related to expired projects not developed within the five-year window as the result of lower-than-anticipated product prices. The remaining 24 MMBoe had not yet expired but were no longer prioritized in our development plans in the current commodity price environment. The majority of these PUDs that were downgraded at management's discretion are located in the San Joaquin basin, meet economic investment criteria at current prices and are anticipated to be developed in the future.

Extensions and discoveries – We added 33 MMBoe from extensions and discoveries, primarily resulting from successful drilling in the San Joaquin and Los Angeles basins.

Improved recovery – We also added 3 MMBoe from improved recovery through IOR and EOR methods, which were associated with the continued development of steamflood and waterflood properties in the San Joaquin basin.

Divestitures – We had a reduction of 10 MMBoe in connection with the Lost Hills divestiture and the Alpine JV entered into during the year. See *Part II, Item 7 Management's Discussion and Analysis, Acquisitions and Divestitures* for more on the Lost Hills divestiture and *Part II, Item 7 Management's Discussion and Analysis, Joint Ventures* for more on the Alpine JV.

We achieved an organic reserve replacement ratio of 111% from our capital program of $455 million, including 16 MMBoe of net positive performance-related revisions. For further information on our organic reserve replacement ratio, see the *PV-10, Standardized Measure and Reserve Replacement Ratio* section below.

2018

Revisions of previous estimates – Our 2018 realized prices for oil and natural gas increased over the prior year by 39% and 14%, respectively, which resulted in positive price-related revisions of 38 MMBoe. We also added 6 MMBoe from net positive performance-related revisions of which 27 MMBoe were from positive technical revisions primarily due to better-than-expected performance and successful drilling efforts in the San Joaquin and Los Angeles basins.

Additionally, at management's discretion, we removed a total of 21 MMBoe of PUDs that were not yet expired but that were not anticipated to be developed within their five-year window of initial booking. Approximately 11 MMBoe of these downgraded PUDs expired in 2019 and were not anticipated to be developed before then at current oil prices. The remaining 10 MMBoe of downgraded PUDs were projects that are no longer prioritized in our development plan based on current project economics.

Improved recovery – We also added 4 MMBoe from improved recovery through proven IOR and EOR methods. The improved recovery additions were associated with the continued development of steamflood and waterflood properties in the San Joaquin basin.

Extensions and discoveries – We added 30 MMBoe from extensions and discoveries, primarily resulting from new geologic interpretations and pressure data in the Ventura basin along with successful drilling in San Joaquin and Los Angeles basins.

Acquisitions – We also added 64 MMBoe in connection with the acquisitions during the year, the majority of which resulted from the Elk Hills transaction.

2017

Revisions of previous estimates – Our total net positive price revision was 49 MMBoe, which was primarily the result of higher prices net of modestly higher operating costs due to the current commodity price environment, partially reinstating reserves that were removed in prior years due to lower prices.

Our net positive performance-related revision of 22 MMBoe resulted primarily from the successful renegotiation of our Huntington Beach royalty agreement and improved performance in the San Joaquin basin, partially offset by negative revisions to remove proved undeveloped reserves due to a downward adjustment of our committed capital in a project area and technical revisions due to updated testing results in one of our project areas.

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

Divestitures – We sold 8 MMBoe of proved reserves based on beginning-of-year reserves balances. Included in this amount was 7 MMBoe of proved undeveloped reserves in the San Joaquin basin conveyed to MIRA as part of our JV with MIRA. There were no material reserves added from improved recovery.

CAPITALIZED COSTS

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

	As of December 31,	
	2019	2018
	(in millions)	
Proved properties	$ 21,285	$ 20,883
Unproved properties	1,055	1,103
Total capitalized costs[(a)]	22,340	21,986
Accumulated depreciation, depletion and amortization[(b)]	(16,300)	(15,839)
Net capitalized costs	$ 6,040	$ 6,147

(a) Includes acquisition and development costs.
(b) Includes accumulated valuation allowance for total unproved properties of $823 and $819 million at December 31, 2019 and 2018, respectively.

COSTS INCURRED

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

	For the years ended December 31,		
	2019	2018	2017
Property acquisition costs		(in millions)	
Proved properties[(a)]	$ 1	$ 553	$ —
Unproved properties	4	1	—
Exploration costs	30	38	25
Development costs[(b)]	505	652	357
Costs incurred	$ 540	$ 1,244	$ 382

(a) Acquisition costs capitalized to proved properties include $8 million of liabilities assumed related to ARO in 2018.
(b) Development costs include a $80 million increase, $7 million decrease and a $5 million decrease in ARO in 2019, 2018 and 2017, respectively. Development costs in 2019 reflect an allocation related to a warrant issued in connection with the Alpine JV of $3 million.

RESULTS OF OPERATIONS

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

	For the years ended December 31,					
	2019		2018		2017	
	(millions)	($/Boe)[a]	(millions)	($/Boe)[a]	(millions)	($/Boe)[a]
Revenues[b]	$ 2,377	$ 50.88	$ 2,359	$ 48.84	$ 1,929	$ 41.04
Production costs[c]	895	19.16	912	18.88	876	18.64
General and administrative expenses[d]	56	1.20	49	1.01	33	0.70
Other operating expenses[e]	71	1.52	51	1.07	26	0.56
Depreciation, depletion and amortization	439	9.40	469	9.71	510	10.85
Taxes other than on income	121	2.59	117	2.42	110	2.34
Exploration expenses	29	0.62	34	0.70	22	0.47
Pretax income	766	16.39	727	15.05	352	7.48
Income tax expense[f]	(205)	(4.39)	(180)	(3.85)	(115)	(2.45)
Results of operations	$ 561	$ 12.00	$ 547	$ 11.20	$ 237	$ 5.03

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

(b) Revenues include cash settlements on our commodity derivatives which are reported in net derivative (gain) loss from commodity contracts on our consolidated statements of operations.

(c) Production costs are the costs incurred in lifting the oil and natural gas to the surface and include gathering, processing, field storage and insurance on proved properties. Production costs on a per Boe basis, excluding the effects of PSC contracts, were $17.70, $17.47 and $17.48 for 2019, 2018 and 2017, respectively.

(d) For the year ended December 31, 2017, certain pension benefit costs of $1 million have been reclassified to other non-operating expenses to conform to the current year presentation in accordance with new accounting rules adopted on January 1, 2018 related to the presentation of net periodic benefit costs for pension and postretirement benefits in the Consolidated Statements of Operations.

(e) Other operating expenses include accretion expense in 2019, 2018 and 2017. Other operating expenses include transportation costs beginning in 2018 due to the adoption of a new accounting standard related to revenue recognition.

(f) Income taxes are calculated on the basis of a stand-alone tax filing entity. The combined U.S. federal and California statutory tax rate for 2019 and 2018 was 28% and 41% in 2017. The top corporate tax rate was reduced beginning January 1, 2018 as a result of tax reform legislation enacted on December 22, 2017. The effective tax rate for 2018 and 2017 reflects the benefit of enhanced oil recovery tax credits.

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

For purposes of the following disclosures, discounted future net cash flows were computed by applying to our proved oil and natural gas reserves the unweighted arithmetic average of the first-day-of-the-month price for each month within the years ended December 31, 2019, 2018 and 2017, respectively. The realized prices used to calculate future cash flows vary by producing area and market conditions. Future operating and capital costs were determined using the current cost environment applied to expectations of future operating and development activities. Future income tax expense was computed by applying, generally, year-end statutory tax rates (adjusted for permanent differences and tax credits) to the estimated net future pre-tax cash flows, after allowing for the deductions for intangible drilling costs and tax DD&A. The cash flows were discounted using a 10% discount factor. The calculations assumed the continuation of existing economic, operating and contractual conditions at December 31, 2019, 2018 and 2017. Such assumptions, which are prescribed by regulation, have not always proven accurate in the past. Other valid assumptions would give rise to substantially different results.

Standardized Measure of Discounted Future Net Cash Flows

	At December 31,		
	2019	2018	2017
	(in millions)		
Future cash inflows	$ 34,134	$ 42,325	$ 26,685
Future costs			
Production costs[(a)]	(16,724)	(19,452)	(13,988)
Development costs[(b)]	(3,938)	(4,432)	(3,848)
Future income tax expense	(3,180)	(4,231)	(1,585)
Future net cash flows	10,292	14,210	7,264
Ten percent discount factor	(5,061)	(6,935)	(3,499)
Standardized measure of discounted future net cash flows	$ 5,231	$ 7,275	$ 3,765

(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 Reserve Quantities

	For the years ended December 31,		
	2019	2018	2017
	(in millions)		
Beginning of year	$ 7,275	$ 3,765	$ 2,667
Sales of oil and natural gas, net of production and other operating costs	(1,198)	(1,511)	(918)
Changes in price, net of production and other operating costs	(1,998)	3,648	1,405
Previously estimated development costs incurred	556	351	159
Change in estimated future development costs	(283)	(38)	(98)
Extensions, discoveries and improved recovery, net of costs	433	443	177
Revisions of previous quantity estimates[(a)]	(638)	738	737
Accretion of discount	890	427	260
Net change in income taxes	518	(1,356)	(599)
Purchases and sales of reserves in place	(151)	766	(43)
Changes in production rates and other	(173)	42	18
Net change	(2,044)	3,510	1,098
End of year	$ 5,231	$ 7,275	$ 3,765

(a) Includes revisions related to performance and price changes.

ITEM 9 CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A CONTROLS AND PROCEDURES

Management's Annual Assessment of and Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

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

Our management has assessed the effectiveness of our internal control system as of December 31, 2019 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, our management believes that, as of December 31, 2019, our system of internal control over financial reporting is effective.

Our independent auditors, KPMG LLP, have issued a report on our internal control over financial reporting, which is set forth in *Item 8 – Financial Statements and Supplementary Data*.

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer (CEO) and chief financial officer (CFO), has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d- 15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act)), as of the end of the period covered by this Annual Report on Form 10-K. Based on that evaluation, our CEO and CFO have concluded that, as of December 31, 2019, 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 of 1934) identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Limitations on Effectiveness of Controls and Procedures

In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

ITEM 9B OTHER INFORMATION

None.

PART III

ITEM 10 DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated by reference from our Proxy Statement for the 2020 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission (SEC) within 120 days of the fiscal year ended December 31, 2019 (2020 Proxy Statement). See the list of our executive officers and related information below.

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.

EXECUTIVE OFFICERS

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

Name	Employment History	Age at February 26, 2020
Todd A. Stevens	President, Chief Executive Officer and Director since 2014; Occidental Petroleum Corporation Vice President - Corporate Development 2012 to 2014; Oxy Oil & Gas Vice President - California Operations 2008 to 2012; Occidental Petroleum Corporation Vice President - Acquisitions and Corporate Finance 2004 to 2012.	53
Marshall D. Smith	Senior Executive Vice President and Chief Financial Officer since 2014; Ultra Petroleum Corporation Senior Vice President and Chief Financial Officer 2011 to 2014; Ultra Petroleum Corporation Chief Financial Officer 2005 to 2014.	60
Shawn M. Kerns	Executive Vice President - Operations and Engineering since 2018; Executive Vice President - Corporate Development 2014 to 2018; Vintage Production California President and General Manager 2012 to 2014; Occidental of Elk Hills General Manager 2010 to 2012; Occidental of Elk Hills Asset Development Manager 2008 to 2010.	49
Francisco J. Leon	Executive Vice President - Corporate Development and Strategic Planning since 2018; Vice President - Portfolio Management and Strategic Planning 2014 to 2018; Occidental Director - Portfolio Management 2012 to 2014; Occidental Director of Corporate Development and M&A 2010 to 2012; Occidental Manager of Business Development 2008 to 2010.	43
Roy M. 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.	57
Michael L. Preston	Senior Executive Vice President, Chief Administrative Officer and General Counsel - 2019; Executive Vice President, General Counsel and Corporate Secretary 2014 to 2019; Occidental Oil and Gas Vice President and General Counsel 2001 to 2014.	55
Charles F. Weiss	Executive Vice President - Public Affairs since 2014; Occidental Vice President, Health, Environment and Safety 2007 to 2014.	56
Darren Williams	Executive Vice President - Operations and Geoscience since 2018; Executive Vice President - Exploration 2014 to 2018; Marathon Upstream Gabon Limited President and Africa Exploration Manager 2013 to 2014; Marathon Oil Oklahoma Subsurface Manager 2010 to 2013; Marathon Oil Gulf of Mexico Exploration and Appraisal Manager 2008 to 2010.	48

ITEM 11 EXECUTIVE COMPENSATION

The information required by this item is incorporated by reference from our 2020 Proxy Statement. Pursuant to the rules and regulations under the Exchange Act, the information in the *Compensation Discussion and Analysis – Compensation Committee Report* section shall not be deemed to be "soliciting material," or to be "filed" with the SEC, or subject to Regulation 14A or 14C under the Exchange Act or to the liabilities under Section 18 of the Exchange Act, nor shall it be deemed incorporated by reference into any filing under the Securities Act of 1933.

ITEM 12 SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item is incorporated by reference from our 2020 Proxy Statement. See also *Part II, Item 5 – Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities – Securities Authorized for Issuance Under Equity Compensation Plans*.

ITEM 13 CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated by reference from our 2020 Proxy Statement.

ITEM 14 PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated by reference from our 2020 Proxy Statement.

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 the Company and investors may view materiality; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

(a) (1) and (2). Financial Statements

Reference is made to Item 8 of the Table of Contents of this report where these documents are listed.

(a) (3). Exhibits

Exhibit Number	Exhibit Description
2.1	Separation and Distribution Agreement, dated as of November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 2.1 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
3.1	Amended and Restated Certificate of Incorporation of California Resources Corporation (filed as Exhibit 3.1 to Registrant's Current Report on Form 8-K filed June 3, 2016 and incorporated herein by reference).
3.2	Amended and Restated Bylaws of California Resources Corporation (filed as Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed November 10, 2015 and incorporated herein by reference).
4.1	Indenture, dated October 1, 2014, by and among California Resources Corporation, the Guarantors and Wells Fargo Bank, National Association (filed as Exhibit 4.2 to Amendment No. 4 to the Registrant's Information Statement on Form 10 filed October 8, 2014 and incorporated herein by reference).
4.2	Indenture, dated December 15, 2015, by and among California Resources Corporation, the Guarantors and the Bank of New York Mellon Trust Company, N.A. (filed as Exhibit 4.1 to Registrant's Current Report on Form 8-K filed December 18, 2015 and incorporated herein by reference).
4.3	Guarantor Supplemental Indenture dated as of March 5, 2015, among California Resources Corporation, certain guarantors named therein and Wells Fargo Bank, National Association (filed as Exhibit 4.2 to Registrant's Registration Statement on Form S-4 filed March 12, 2015 and incorporated herein by reference).
4.4	Guarantor Supplemental Indenture dated as of March 4, 2016, among California Resources Corporation, certain guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.1 to Registrant's Quarterly Report on Form 10-Q filed August 4, 2016 and incorporated herein by reference).
4.5	Guarantor Supplement Indenture dated as of March 4, 2016, among California Resources Corporation, certain guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.2 to Registrant's Quarterly Report on Form 10-Q filed August 4, 2016 and incorporated herein by reference).

Exhibit Number	Exhibit Description
4.6	Guarantor Supplemental Indenture No. 2, dated as of April 29, 2016, among California Resources Corporation, certain guarantors named therein and Wilmington Trust, National Association, as trustee (filed as Exhibit 10.4 to Registrant’s Quarterly Report on Form 10-Q filed August 4, 2016 and incorporated herein by reference).
4.7	Assumption Agreement dated as of March 6, 2015, among CRC Construction Services, LLC and JP Morgan Chase Bank, N.A., as Administrative Agent for lenders (filed as Exhibit 10.31 to Registrant’s Registration Statement on Form S-4 filed March 12, 2015 and incorporated herein by reference).
4.8	Registration Rights Agreement, dated October 1, 2014, by and among California Resources Corporation, the Guarantors and the Initial Purchasers (filed as Exhibit 4.3 to Amendment No. 4 to the Registrant’s Information Statement on Form 10 filed October 8, 2014 and incorporated herein by reference).
4.9	Form of 5% Senior Note due 2020 (included in Exhibit 4.2 to Amendment No. 4 to the Registrant's Information Statement on Form 10 filed October 8, 2014 and incorporated herein by reference).
4.10	Form of 5½% Senior Note due 2021 (included in Exhibit 4.2 to Amendment No. 4 to the Registrant's Information Statement on Form 10 filed October 8, 2014 and incorporated herein by reference).
4.11	Form of 6% Senior Note due 2024 (included in Exhibit 4.2 to Amendment No. 4 to the Registrant's Information Statement on Form 10 filed October 8, 2014 and incorporated herein by reference).
4.12	Form of 8% Senior Secured Second Lien Note due 2022 (included in Exhibit 4.1 to Registrant's Current Report on Form 8-K filed December 18, 2015 and incorporated herein by reference).
4.13	Registration Rights Agreement, dated as of April 9, 2018, by and between California Resources Corporation and Chevron U.S.A. Inc. (filed as Exhibit 4.01 to the Registrant’s Current Report on Form 8-K filed April 9, 2018, and incorporated herein by reference).
4.14	Guarantor Supplemental Indenture, dated as of April 16, 2018, among California Resources Corporation, certain guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.1 to the Registrant’s Quarterly Report on Form 10-Q filed August 2, 2018, and incorporated herein by reference).
4.15	Third Guarantor Supplemental Indenture, dated as of June 29, 2018, among California Resources Corporation, certain guarantors named therein and Wilmington Trust, National Association, as trustee (filed as Exhibit 4.2 to the Registrant’s Quarterly Report on Form 10-Q filed August 2, 2018, and incorporated herein by reference).
4.16*	Description of Registrant's Securities.
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).
10.4	Third Amendment to Credit Agreement, dated February 23, 2016, among California Resources Corporation and JP Morgan Chase Bank, N.A., as Administrative Agent, a Swingline Lender and a Letter of Credit Issuer and Bank of America, N.A. as Syndication Agent, a Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 99.1 to the Registrant's Current Report on Form 8-K filed February 23, 2016, and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.5	Fourth Amendment to Credit Agreement dated as of April 22, 2016, among California Resources Corporation, as the Borrower and JP Morgan Chase Bank, N.A., as Administrative Agent, a Swingline Lender and a Letter of Credit Issuer and Bank of America, N.A., as Syndication Agent, Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 99.1 to the Registrant's Current Report on Form 8-K filed April 22, 2016, and incorporated herein by reference).
10.6	Fifth Amendment and Waiver to Credit Agreement, dated August 12, 2016, among California Resources Corporation, as the Borrower and JP Morgan Chase Bank, N.A., as Administrative Agent, a Swingline Lender and a Letter of Credit Issuer and Bank of America, N.A., as Syndication Agent, a Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 10.2 to the Registration's Current Report on Form 8-K filed August 17, 2016 and incorporated herein by reference).
10.7	Sixth Amendment to Credit Agreement, dated as of February 14, 2017, among California Resources Corporation, as the Borrower, JP Morgan Chase Bank, N.A., as Administrative Agent, Swingline Lender and a Letter of Credit Issuer, Bank of America, N.A., as Syndication Agent, Swingline Lender and a letter of Credit Issuer, and the Lenders (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed February 16, 2017, and incorporated herein by reference).
10.8	Seventh Amendment to Credit Agreement, dated as of November 9, 2017, among California Resources Corporation, as the Borrower, JP Morgan Chase Bank, N.A., as Administrative Agent, Swingline Lender and a Letter of Credit Issuer, Bank of America, N.A., as Syndication Agent, Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed November 13, 2017, and incorporated herein by reference).
10.9	Eighth Amendment to 2014 Credit Agreement, dated August 20, 2018 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed August 24, 2018 and incorporated herein by reference).
10.10	Credit Agreement, dated August 12, 2016, among California Resources Corporation, as the Borrower, the several Lenders from time to time parties thereto, Goldman Sachs Bank USA, as Lead Arranger and Bookrunner, and The Bank of New York Mellon Trust Company, N.A., as Administrative Agent and Collateral Agent (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed August 17, 2016 and incorporated herein by reference).
10.11	Credit Agreement, dated as of November 17, 2017, by and among the Company, as the Borrower, Bank of New York Mellon Trust, N.A., as Administrative Agent, and the various Lenders identified therein (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed November 17, 2017, and incorporated herein by reference).
10.12	First Amendment to 2017 Credit Agreement, dated September 18, 2018 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed September 18, 2018, and incorporated herein by reference).
10.13	Omnibus Amendment, dated September 12 2016, among California Resources Corporation, the Guarantors party thereto, the Collateral Trustee and the other party lien representatives party thereto (filed as Exhibit 10.3 to the Registration's Quarterly Report on Form 10-Q filed November 3, 2016 and incorporated herein by reference).
10.14	Transition Services Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.4 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.15	Tax Sharing Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.2 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.16	Employee Matters Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.3 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.17	Intellectual Property License Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.7 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.18	Area of Mutual Interest Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.5 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.19	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).
10.20	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).
10.21	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).
10.22	Confidentiality and Trade Secret Protection Agreement, dated November 25, 2014, by and between Occidental Petroleum Corporation and California Resources Corporation, dated November 24, 2014 (filed as Exhibit 10.6 to the Company's Current Report on Form 8-K filed on December 1, 2014, and incorporated herein by reference).
10.23	Second Amended and Restated Limited Liability Company Agreement of Elk Hills Power, LLC, dated as of February 7, 2018, by and among Elk Hills Power, LLC, California Resources Elk Hills, LLC and ECR Corporate Holdings L.P. (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on February 7, 2018, and incorporated herein by reference).
10.24	Commercial Agreement, dated as of February 7, 2018, by and between Elk Hills Power, LLC and California Resources Elk Hills, LLC (filed as Exhibit 10.2 to the Company’s Current Report on Form 8-K filed on February 7, 2018, and incorporated herein by reference).
10.25	Master Services Agreement, dated as of February 7, 2018, by and between Elk Hills Power, LLC and California Resources Elk Hills, LLC (filed as Exhibit 10.3 to the Company’s Current Report on Form 8-K filed on February 7, 2018, and incorporated herein by reference).
10.26	Form of Stock Purchase Agreement, dated as of February 7, 2018 (filed as Exhibit 10.4 to the Company’s Current Report on Form 8-K filed on February 7, 2018, and incorporated herein by reference).
10.27	Registration Rights Agreement, dated as of February 7, 2018, by and between California Resources Corporation and the purchasers named therein (filed as Exhibit 10.5 to the Company’s Current Report on Form 8-K filed on February 7, 2018, and incorporated herein by reference).
	The following are management contracts and compensatory plans required to be identified specifically as responsive to Item 601(b)(10)(iii)(A) of Regulation S-K pursuant to Item 15(b) of Form 10-K.
10.29	California Resources Corporation Long-Term Incentive Plan, 2016 Annual Incentive Award Summary (filed as Exhibit 10.5 on Registrant’s Quarterly Report on Form 10-Q filed August 4, 2016 and incorporated herein by reference).
10.31	California Resources Corporation Long-Term Incentive Plan Nonstatutory Stock Option Award Terms and Conditions (filed as Exhibit 10.4 to the Registrant’s Quarterly Report Form 10-Q filed November 6, 2015, and incorporated herein by reference).
10.32	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).
10.33	First Amendment to California Resources Corporation Supplemental Savings Plan (filed as Exhibit 10.18 to the Registrant's Annual Report on Form 10-K filed February 29, 2016, and incorporated herein by reference).
10.34	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).

Exhibit Number	Exhibit Description
10.35	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).
10.36	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).
10.37*	First Amendment to California Resources Corporation Long-Term Incentive Plan (As Amended and Restated Effective as of May 4, 2016).
10.38	Acknowledgment of Amendment to Long-Term Incentive Award Terms with William E. Albrecht (filed as Exhibit 10.22 to the Registrant's Annual Report on Form 10-K filed February 29, 2016, and incorporated herein by reference).
10.39	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).
10.40	Form of Restricted Stock Unit Award Terms and Conditions (filed as Exhibit 10.6 to the Registrant's Quarterly Report on Form 10-Q filed August 4, 2016 and incorporated herein by reference).
10.41	Form of Nonstatutory Stock Option Award Terms and Conditions (filed as Exhibit 10.5 to the Registrant's Quarterly Report on Form 10-Q filed November 3, 2016, and incorporated herein by reference).
10.42	Form of Performance Incentive Award Terms and Conditions (filed as Exhibit 10.6 to the Registrant's Quarterly Report on Form 10-Q filed November 3, 2016, and incorporated herein by reference).
10.45	Form of Restricted Stock Unit Award for Non-Employee Directors Grant Agreement (filed as Exhibit 10.9 to Amendment No. 3 to the Registrant's Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.50	Form of 2018 Nonstatutory Stock Option Award Terms and Conditions (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed May 9, 2018, and incorporated herein by reference).
10.51	Form of 2018 Restricted Stock Unit Award Terms and Conditions (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q filed May 9, 2018, and incorporated herein by reference).
10.52	Form of 2018 Performance Stock Unit Award Terms and Conditions (filed as Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q filed May 9, 2018, and incorporated herein by reference).
10.53	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).
10.54	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).
10.55	First Amendment to the California Resources Corporation 2014 Employee Stock Purchase Plan effective May 4, 2016 (filed as Annex C-1 to the Registrant's Definitive Proxy Statement on Schedule 14A filed March 23, 2016 and incorporated herein by reference).
10.56	Second Amendment to the California Resources Corporation 2014 Employee Stock Purchase Plan effective May 9, 2018 (incorporated by reference herein to Annex B-1 to the Registrant's Definitive Proxy Statement on Schedule 14A (File No. 001-36478) filed on March 27, 2018).
10.57	Form of 2019 Nonstatutory Stock Option Award Terms and Conditions (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10–Q filed May 2, 2019 and incorporated herein by reference).
10.58	Form of 2019 Restricted Stock Unit Award Terms and Conditions (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10–Q filed May 2, 2019 and incorporated herein by reference).
10.59	Form of 2019 Performance Stock Unit Award Terms and Conditions (filed as Exhibit 10.3 to the Registrant's Quarterly Report on Form 10–Q filed May 2, 2018 and incorporated herein by reference).
10.60	California Resources Corporation Long–Term Incentive Plan, as amended and restated effective as of May 8, 2019 (filed as Exhibit 4.3 to the Registrant's related Registration Statement on Form S-8 filed May 9, 2019 and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.61	Purchase Warrant for Common Stock, dated July 22, 2019 (filed as Exhibit 4.1 to the Registrant’s Current Report on Form 8–K filed July 23, 2019 and incorporated herein by reference).
10.62	Ninth Amendment to Credit Agreement, dated as of August 28, 2019, among California Resources Corporation, as the Borrower, JP Morgan Chase Bank, N.A., as Administrative Agent, Swingline Lender and a Letter of Credit Issuer, Bank of America, N.A., as Syndication Agent, Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 10.1 to the Registrant’s Current Report on Form 8–K filed September 3, 2019, and incorporated herein by reference).
21*	List of Subsidiaries of California Resources Corporation.
23.1*	Consent of Independent Registered Public Accounting Firm.
23.2*	Consent of Independent Petroleum Engineers, Ryder Scott.
23.3*	Consent of Independent Petroleum Engineers, Netherland, Sewell & Associates.
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, 2019.
99.2*	Netherland, Sewell & Associates Estimated Future Reserves Attributable to Certain Leasehold and Royalty Interests as of December 31, 2019.
101.INS*	Inline XBRL Instance Document.
101.SCH*	Inline XBRL Taxonomy Extension Schema Document.
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document.
104	Cover Page Interactive Data File (formatted in inline XBRL and contained in Exhibits 101).

* - Filed herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CALIFORNIA RESOURCES CORPORATION

February 26, 2020	By:	/s/ Todd A. Stevens
		Todd A. Stevens President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

	Title	Date
/s/ Todd A. Stevens Todd A. Stevens	President, Chief Executive Officer and Director	February 26, 2020
/s/ Marshall D. Smith Marshall D. Smith	Senior Executive Vice President and Chief Financial Officer	February 26, 2020
/s/ Roy Pineci Roy Pineci	Executive Vice President - Finance and Principal Accounting Officer	February 26, 2020
/s/ William E. Albrecht William E. Albrecht	Chairman of the Board	February 26, 2020
/s/ Justin A. Gannon Justin A. Gannon	Director	February 26, 2020
/s/ Harry T. McMahon Harry T. McMahon	Director	February 26, 2020
/s/ Richard W. Moncrief Richard W. Moncrief	Director	February 26, 2020
/s/ Avedick B. Poladian Avedick B. Poladian	Director	February 26, 2020
/s/ Anita M. Powers Anita M. Powers	Director	February 26, 2020
/s/ Laurie A. Siegel Laurie A. Siegel	Director	February 26, 2020
/s/ Robert V. Sinnott Robert V. Sinnott	Director	February 26, 2020

Exhibit 4.16

DESCRIPTION OF SECURITIES

As of December 31, 2019, we had registered our common stock under Section 12 of the Exchange Act. The following is a description of the material terms of our common stock as provided in our amended and restated certificate of incorporation and amended and restated bylaws. The summaries and descriptions below do not purport to be complete statements of the relevant provisions of these documents. For a complete description, we refer you to, and the following summaries and descriptions are qualified in their entirety by reference to, our amended and restated certificate of incorporation and amended and restated bylaws, copies of which will be filed as exhibits to the registration statement of which this prospectus forms a part.

Authorized Capitalization

Our authorized capital stock consists of (i) 20,000,000 shares of preferred stock, par value $0.01 per share, of which no shares were issued and outstanding as of December 31, 2019 and (ii) 200,000,000 shares of common stock, par value $0.01 per share, of which 49,175,843 shares were issued and outstanding as of December 31, 2019.

Common Stock

Except as provided by law or in a preferred stock designation, holders of our common stock are entitled to one vote for each share held of record on all matters submitted to a vote of the stockholders, have the exclusive right to vote for the election of directors and do not have cumulative voting rights. Directors are elected to our board if the number of the validly cast “for” votes exceeds the number of validly cast “against” or “withheld” votes, collectively, with respect to such election except, that directors are elected by a plurality of the validly cast votes represented in person or by proxy with respect to their election if the number of nominees for director exceeds the number of directors to be elected as set forth in our bylaws. Except as otherwise required by law, holders of our common stock are not entitled to vote on any amendment to the amended and restated certificate of incorporation (including any certificate of designations relating to any series of preferred stock) that relates solely to the terms of any outstanding series of preferred stock if the holders of such affected series are entitled, either separately or together with the holders of one or more other such series, to vote thereon pursuant to the amended and restated certificate of incorporation (including any certificate of designations relating to any series of preferred stock) or pursuant to the Delaware General Corporation Law (“DGCL”). Subject to prior rights and preferences that may be applicable to any outstanding shares or series of our preferred stock, holders of our common stock are entitled to receive ratably in proportion to the shares of our common stock held by them such dividends (payable in cash, stock or otherwise), if any, as may be declared from time to time by our board of directors out of funds legally available for dividend payments. All outstanding shares of our common stock are fully paid and non-assessable. The holders of our common stock have no preferences or rights of conversion, exchange, pre-emption or other subscription rights. There are no redemption or sinking fund provisions applicable to our common stock. In the event of any voluntary or involuntary liquidation, dissolution or winding-up of our affairs, holders of our common stock are entitled to share ratably in our assets in proportion to the shares of common stock held by them that are remaining after payment or provision for payment of all of our debts and obligations and after distribution in full of preferential amounts to be distributed to holders of outstanding shares of preferred stock, if any.

Preferred Stock

Our amended and restated certificate of incorporation authorizes our board of directors, subject to any limitations prescribed by law, without further stockholder approval, to establish and to issue from time to time one or more series of preferred stock, par value $0.01 per share, covering up to an aggregate of 20,000,000 shares of preferred stock. Each series of our preferred stock will cover the number of shares and will have the powers, preferences, rights, qualifications, limitations and restrictions determined by board of directors, which may include, among others, dividend rights, liquidation preferences, voting rights, conversion or exchange rights, preemptive rights and redemption rights. Except as provided by law or in a preferred stock designation, the holders of our preferred stock will not be entitled to vote at or receive notice of any meeting of stockholders.

Anti-Takeover Effects of Provisions of Our Amended and Restated Certificate of Incorporation, Our Amended and Restated Bylaws and Delaware Law

Some provisions of Delaware law, our amended and restated certificate of incorporation and our amended and restated bylaws could make acquisition of control of our company by means of a tender offer, a proxy contest or otherwise or removal of our incumbent officers and directors more difficult. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could make it more difficult to accomplish or could deter transactions that stockholders may otherwise consider to be in their best interests or in our best interests, including transactions that might result in a premium over the market price for our shares.

These provisions are designed to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with our board of directors. We believe that the benefits of increased protection and our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire control of our company outweigh the disadvantages of discouraging these proposals because, among other things, negotiation of these proposals could result in an improvement of their terms.

Delaware Law

We are subject to Section 203 of the DGCL, which generally prohibits a Delaware corporation, including those whose securities are listed for trading on the NYSE, from engaging in any business combination with any interested stockholder (which is defined generally as a person owning 15% or more of a Delaware corporation’s outstanding voting stock) or its affiliates or associates for a period of three years following the time that the stockholder became an interested stockholder, unless:

- the transaction is approved by the board of directors before the time the interested stockholder attained that status;

- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced; or
- on or after such time the business combination is approved by the board of directors and authorized at a meeting of stockholders by at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

We may elect in the future to not be subject to the provisions of Section 203 of the DGCL.

Amended and Restated Certificate of Incorporation and Amended and Restated Bylaws

Provisions of our amended and restated certificate of incorporation and amended and restated bylaws may delay or discourage transactions involving an actual or potential change in control or change in our management, or transactions that our stockholders might otherwise deem to be in their best interests or in our best interests, including transactions that might result in a premium over the market price for our shares. Therefore, these provisions could adversely affect the price of our common stock.

Among other things our amended and restated certificate of incorporation and amended and restated bylaws:

- establish advance notice procedures with regard to stockholder proposals relating to the nomination of candidates for election as directors or new business to be brought before meetings of our stockholders. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not later than 90 days nor earlier than 120 days prior to the first anniversary date of the annual meeting for the preceding year. Our amended and restated bylaws specify the requirements as to form and content of all stockholder notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting, and may discourage or deter a third party from conducting a solicitation of proxies to elect its slate of directors or to approve its proposal, without regard to whether consideration of those nominees or proposals might be harmful or beneficial to us and our stockholders;
- provide our board of directors the ability to authorize undesignated preferred stock. This ability makes it possible for our board of directors to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of us. These provisions may have the effect of deterring hostile takeovers or delaying changes in control or management of our company;
- provide that (x) the authorized number of directors may be changed only by resolution of the board of directors and (y) all vacancies, including newly created directorships, may, except as otherwise required by law or, if applicable, the rights of holders of a series of preferred stock, only be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum. "Cause" is defined as the director's (i) conviction of a serious felony involving moral turpitude or a violation of federal or state securities laws; (ii) the commission of any material act of dishonesty resulting or intended to result in material personal gain or enrichment of such director at the expense of CRC or any of its subsidiaries and which act, if made the subject of criminal charges, would be reasonably likely to be charged as a felony; or (iii) adjudication as legally incompetent by a court of competent jurisdiction. These provisions may have the effect of deterring hostile takeovers or delaying changes in control or management of our company;
- provide that (i) any action required or permitted to be taken by the stockholders must be effected at a duly called annual or special meeting of stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders, subject to the rights of the holders of any series of our preferred stock with respect to such series, and (ii) special meetings of our stockholders may only be called by the board of directors, the chief executive officer or the chairman of the board. These provisions regarding our stockholder meetings may have the effect of deterring hostile takeovers or delaying changes in control or management of our company; and
- provide that (i) certain provisions of our certificate of incorporation related to the voting rights of stockholders, our board of directors, special meetings of our stockholders, the ability of our stockholders to act by written consent, the forum for certain disputes related to us or our stockholders, and the applicability of Section 203 DGCL may be amended only by the affirmative vote of the holders of at least 75% of the voting power of our then outstanding common stock and that other provisions of our certificate of incorporation may be amended upon the affirmative vote of the holders of at least a majority of our then outstanding common stock, in each case, in addition to the approval of a majority of our directors then in office and (ii) our bylaws can be amended or repealed at any regular or special meeting of stockholders or by the board of directors but any amendment by the stockholders will require the affirmative vote of the holders of at least 75% of the voting power of the shares of our common stock outstanding and entitled to vote thereon. These provisions regarding the amendment of our constituent documents may have the effect of deterring hostile takeovers or delaying changes in control or management of our company.

Forum Selection

Our amended and restated certificate of incorporation provides that unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for:

- any derivative action or proceeding brought on our behalf;
- any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders;
- any action asserting a claim arising pursuant to any provision of the DGCL, our amended and restated certificate of incorporation or our bylaws (as either may be amended from time to time); or
- any action asserting a claim that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein.

Our amended and restated certificate of incorporation also provides that any person or entity purchasing or otherwise holding any interest in shares of our capital stock will be deemed to have notice of and to have consented to this forum selection provision. However, it is possible that a court could find our forum selection provision to be inapplicable or unenforceable.

EXHIBIT 21

LIST OF OPERATING SUBSIDIARIES

The following is a list of our subsidiaries at December 31, 2019 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 Development JV, LLC	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 Real Estate Ventures, LLC	Delaware
California Resources Royalty Holdings, LLC	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

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors
California Resources Corporation:

We consent to the incorporation by reference in the registration statements (Nos. 333-200610, 333-200611, 333-211106, 333-211107, 333-224868, 333-226616, 333-228426, 333-231314 and 333-233289) on Forms S-8 and S-3 of California Resources Corporation of our report dated February 26, 2020, with respect to the consolidated balance sheets of California Resources Corporation and subsidiaries as of December 31, 2019 and 2018, the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements), and the effectiveness of internal control over financial reporting as of December 31, 2019, which report appears in the December 31, 2019 annual report on Form 10-K of California Resources Corporation.

Our report refers to a change in the method of accounting for leases in 2019 due to the adoption of Accounting Standards Codification Topic 842, *Leases*.

/s/ KPMG LLP

Los Angeles, California
February 26, 2020

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

To the Board of Directors
California Resources Corporation:

We consent to the (i) inclusion in the California Resources Corporation (“CRC”) Form 10-K for the year ended December 31, 2019, and the incorporation by reference in CRC’s registration statements (Nos. 333-200610, 333-200611, 333-211106, 333-211107, 333-224868, 333-226616, 333-228426, 333-231314 and 333-233289) (the “Registration Statements”), of references to our name and to our letter dated January 10, 2020, relating to our audit of certain oil and gas proved reserves of CRC as of December 31, 2019 (our “Letter”), (ii) filing of our Letter with the Securities and Exchange Commission as Exhibit 99.1 to the Form 10-K and (iii) incorporation by reference of our Letter in the Registration Statements.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
February 26, 2020

EXHIBIT 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We consent to the incorporation by reference in the registration statements (Nos. 333-224868, 333-228426 and 333-233289 on Form S-3, and registration statements (Nos. 333-200610,333-200611, 333-211106, 333-211107, 333-226616 and 333-231314) on Form S-8 of California Resources Corporation (the “Company”) of the reference to Netherland, Sewell & Associates, Inc. and the inclusion of our report dated February 12, 2020 in the Company’s Annual Report on Form 10-K for the year ended December 31, 2019, filed with the Securities and Exchange Commission.

/s/ Netherland, Sewell & Associates, Inc.

NETHERLAND, SEWELL & ASSOCIATES, INC.
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
February 26, 2020

EXHIBIT 31.1

RULE 13a – 14(a) / 15d – 14(a)
CERTIFICATION
PURSUANT TO §302 OF THE SARBANES-OXLEY ACT OF 2002

I, Todd A. Stevens, certify that:

1. I have reviewed this annual report on Form 10-K of California Resources Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2020

/s/ Todd A. Stevens

Todd A. Stevens
President and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.2

RULE 13a – 14(a) / 15d – 14(a)
CERTIFICATION
PURSUANT TO §302 OF THE SARBANES-OXLEY ACT OF 2002

I, Marshall D. Smith, certify that:

1. I have reviewed this annual report on Form 10-K of California Resources Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2020

/s/ Marshall D. Smith

Marshall D. Smith
Senior Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 32.1

CERTIFICATION OF CEO AND CFO PURSUANT TO
18 U.S.C. § 1350,
AS ADOPTED PURSUANT TO
§ 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of California Resources Corporation (the "Company") for the fiscal period ended December 31, 2019, as filed with the Securities and Exchange Commission on February 26, 2020 (the "Report"), Todd A. Stevens, as Chief Executive Officer of the Company, and Marshall D. Smith, as Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his or her knowledge, respectively:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Todd A. Stevens

Name:	Todd A. Stevens
Title:	President and Chief Executive Officer
Date:	February 26, 2020

/s/ Marshall D. Smith

Name:	Marshall D. Smith
Title:	Senior Executive Vice President and Chief Financial Officer
Date:	February 26, 2020

A signed original of this written statement required by Section 906 has been provided to California Resources Corporation and will be retained by California Resources Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

CALIFORNIA RESOURCES CORPORATION

Estimated

Future Reserves

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2019

\s\ Larry P. Connor	\s\ Eric A. Sepolio
Larry P. Connor, P.E.	Eric A. Sepolio, P.E.
TBPE License No. 58639	TBPE License No. 128738
Executive Vice President	Vice President

[SEAL] **[SEAL]**

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 10, 2020

California Resources Corporation
9200 Oakdale Avenue
Los Angeles, CA 91311

Ladies and Gentlemen:

At the request of California Resources Corporation (CRC), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2019 prepared by CRC's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our reserves audit, completed on January 10, 2020 and presented herein, was prepared for public disclosure by CRC in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves shown herein represent CRC's estimated net reserves attributable to the leasehold and royalty interests in certain properties owned by CRC and the portion of those reserves reviewed by Ryder Scott, as of December 31, 2019. The properties reviewed by Ryder Scott incorporate CRC reserves determinations and are located in the state of California.

The properties reviewed by Ryder Scott account for a portion of CRC's total net proved reserves as of December 31, 2019. Based on the estimates of total net proved reserves prepared by CRC, the reserves audit conducted by Ryder Scott addresses 40 percent of the total proved developed net liquid hydrocarbon reserves and 64 percent of the total proved developed net gas reserves or 44 percent of the total proved developed net reserves on a barrel of oil equivalent (BOE) basis. The report addresses 32 percent of the total proved undeveloped net liquid hydrocarbon reserves and 66 percent of the total proved undeveloped net gas reserves, or 36 percent of the total proved undeveloped net reserves on a BOE basis of CRC.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserve quantities and/or Reserves Information." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Based on our review, including the data, technical processes and interpretations presented by CRC, it is our opinion that the overall procedures and methodologies utilized by CRC in preparing their estimates of the proved reserves as of December 31, 2019 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by CRC are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. CRC has informed us that in the preparation of their reserves and income projections, as of December 31, 2019, they used average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period and subject to adjustments for differentials, by geographic area where the hydrocarbons are sold; unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by CRC attributable to CRC's interest in properties that we reviewed and for those that we did not review are summarized below:

SEC PARAMETERS
Estimated Net Reserves
Certain Leasehold and Royalty Interests of
California Resources Corporation

As of December 31, 2019

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Audited by Ryder Scott				
Net Reserves				
Oil/Condensate – MMBarrels	93	30	36	159
Plant Products – MMBarrels	35	3	6	44
Gas – Bcf	318	30	73	421
MMBOE	181	38	54	273
Not Audited by Ryder Scott				
Net Reserves				
Oil/Condensate – MMBarrels	178	56	90	324
Plant Products – MMBarrels	5	2	1	8
Gas – Bcf	153	42	38	233
MMBOE	209	65	97	371
Total Net Reserves				
Oil/Condensate – MMBarrels	271	86	126	483
Plant Products – MMBarrels	40	5	7	52
Gas – Bcf	471	72	111	654
MMBOE	390	103	151	644

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as millions of barrels (MMBarrels). The gas volumes are generally reported on an “as sold basis” expressed in billions of cubic feet (Bcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. These gas volumes do include volumes of gas consumed in operations; though these volumes are not material. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MMBOE means million barrels of oil equivalent.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various proved reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of behind pipe zones and volumes associated with certain recently completed projects not yet reflected in the producing category.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At CRC's request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas 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…" The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves, prepared by CRC, for the properties that we reviewed were estimated by performance methods, the volumetric method, analogy, or a combination of methods. The proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of historical production and pressure data available through December 2019, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by CRC or obtained from public data sources and were considered sufficient for the purpose thereof.

The proved developed non-producing and undeveloped reserves that we reviewed were estimated by the volumetric method, analogy, or a combination of methods. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by CRC for our review or which we have obtained from public data sources that were available through December 2019. The data utilized from the analogs in conjunction with well and seismic data incorporated into the volumetric analysis were considered sufficient for the purpose thereof.

For the reserves audited by Ryder Scott, approximately 25 percent will be produced by steamflood and gas injection recovery processes, 10 percent will be produced by waterflood and water drive processes, and the remaining 65 percent will be produced by primary recovery. Approximately 5 percent of the reserves forecast are expected to be recovered from horizontal wells.

To estimate economically recoverable proved oil and gas reserves, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by CRC relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices furnished by CRC for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon prices in effect on December 31, 2019 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used by CRC for the geographic areas reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used by CRC to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as “differentials.” The differentials used by CRC were reviewed by us for their reasonableness using information furnished by CRC for this purpose.

The table below summarizes CRC’s net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as CRC’s “average realized prices.” The average realized prices shown in the table below were determined from CRC’s estimate of the total future gross revenue before production taxes for the properties reviewed by us and CRC’s estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the following table is presented in accordance with SEC disclosure requirements for the geographic area reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	Brent Spot	$63.15/Bbl	$66.29/Bbl
	NGLs	Brent Spot	$63.15/Bbl	$31.58/Bbl
	Gas	Henry Hub	$2.58/MMBTU	$2.86/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in CRC's individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserves estimates reviewed. The proved gas volumes presented herein include volumes of gas consumed in operations as reserves; those volumes are not material.

Operating costs furnished by CRC are based on the operating expense reports of CRC and include only those costs directly applicable to the leases, contract areas, or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases, contract areas and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases, contract areas and wells under terms of operating agreements. The operating costs furnished by CRC were reviewed by us for their reasonableness using information furnished by CRC for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases, contract areas or wells.

Development costs furnished by CRC are based on authorizations for expenditure (AFE) for the proposed work or actual costs for similar projects. The development costs furnished by CRC were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by CRC. The estimated net cost of abandonment after salvage was included by CRC for properties where abandonment costs net of salvage were material. CRC's estimates of the net abandonment costs were accepted without independent verification.

The proved developed non-producing and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with CRC's plans to develop these reserves as of December 31, 2019. The implementation of CRC's development plans as presented to us is subject to the approval process adopted by CRC's management. As the result of our inquiries during the course of our review, CRC has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by CRC's management at the appropriate local, regional and corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to CRC. CRC has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, CRC has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2019, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by CRC were held constant throughout the life of the properties.

CRC's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by CRC to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by CRC. Wells or locations that are not currently producing may start producing earlier or later than anticipated in CRC's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and recompleting wells and constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and operating conditions, producing market demand and allowables or other constraints set by regulatory bodies.

CRC's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a review of the properties in which CRC owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by CRC for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of CRC are responsible for the preparation of reserves estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

CRC has informed us that they have furnished or otherwise made available to us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of CRC's forecast of future proved production, we have relied upon data furnished by CRC with respect to property interests owned or otherwise held, production and well tests from examined wells, normal direct costs of operating the wells or leases, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by CRC. We consider the factual data furnished to us by CRC to be appropriate and sufficient for the purpose of our review of CRC's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by CRC and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by CRC, it is our opinion that the overall procedures and methodologies utilized by CRC in preparing their estimates of the proved reserves as of December 31, 2019 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by CRC are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards. Ryder Scott found the processes and controls used by CRC in their estimation of proved reserves to be effective and, in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

We were in reasonable agreement with CRC's estimates of proved reserves for the properties which we reviewed; although in certain cases there was more than an acceptable variance between CRC's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to CRC when its reserves estimates were prepared. However notwithstanding, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned by CRC.

Other Properties

Other properties, as used herein, are those properties of CRC which we did not review. The proved net reserves attributable to the other properties account for 62 percent of the total proved net liquid hydrocarbon reserves and 36 percent of the total proved net gas reserves or 58 percent of the total proved net reserves on an equivalent barrel, BOE, basis based on estimates prepared by CRC as of December 31, 2019.

The same technical personnel of CRC were responsible for the preparation of the reserves estimates for the properties that we reviewed as well as for the properties not reviewed by Ryder Scott.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer’s license or a registered or certified professional geoscientist’s license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to CRC. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by CRC.

CRC makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, CRC has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and S-8 of CRC, of the references to our name, as well as to the references to our third party report for CRC, which appears in the December 31, 2019 annual report on Form 10-K of CRC. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by CRC.

We have provided CRC with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by CRC and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

\s\ Larry P. Connor

Larry P. Connor, P.E.
TBPE License No. 58639
Executive Vice President **[SEAL]**

\s\ Eric A. Sepolio

Eric A. Sepolio, P.E.
TBPE License No. 128738
Vice President **[SEAL]**

LPC-EAS (DCR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Larry Connor was the primary technical person responsible for preparing the estimate of the reserves and future production included in this report.

Mr. Connor, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 1981, is the Executive Vice President and is responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Connor served in a number of engineering positions with Amoco Production Company. For more information regarding Mr. Connor's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Connor earned a Bachelor of Science degree in Industrial Engineering from Texas A&M University in 1977 and is a licensed Professional Engineer in the State of Texas, and the Provinces of Alberta, British Columbia and Saskatchewan, Canada. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. Mr. Connor has served as the Chairman of the Houston Chapter of the Society of Petroleum Evaluation Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Connor fulfills. Mr. Connor attended an additional 25 hours of formalized in-house training during 2019 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants. In addition to internal training, Mr. Connor has organized and participated in a total of 12 hours of industry training to professionals outside of Ryder Scott. Mr. Connor has served as course instructor for the formalized in-house training of PSA programming using PHDWin™ software to analyze prospect evaluations.

Based on his educational background, professional training and more than 42 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Connor has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

<u>*Note to paragraph (a)(26):*</u> *Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (<u>i.e.</u>, absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (<u>i.e.</u>, potentially recoverable resources from undiscovered accumulations).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas 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—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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental

entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and

producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

February 12, 2020

Ms. Elizabeth DeStephens
California Resources Corporation
27200 Tourney Road, Suite 200
Santa Clarita, California 91355

Dear Ms. DeStephens:

In accordance with your request, we have audited the estimates prepared by California Resources Corporation (CRC), as of December 31, 2019, of the proved reserves to the CRC interest in certain oil and gas properties located in California. The scope of our work did not include auditing the future net revenue associated with these reserves. It is our understanding that the proved reserves estimates shown herein constitute approximately 38 percent of all proved reserves owned by CRC. Economic analysis was performed by CRC only to confirm economic producibility and determine economic limits for the properties. We have examined the estimates with respect to reserves quantities, reserves categorization, future producing rates, and economic producibility using the definitions set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Rule 4-10(a). The estimates of reserves have been prepared in accordance with the definitions and regulations of the SEC and conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. We completed our audit on or about the date of this letter. This report has been prepared for CRC's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

The following table sets forth CRC's estimates of the net reserves, as of December 31, 2019, for the audited properties:

	Net Reserves		
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)
Proved Developed Producing	132,105.4	10.2	55,207.2
Proved Developed Non-Producing	36,650.8	2.1	24,065.3
Proved Undeveloped	60,598.5	18.0	25,015.1
Total Proved	229,354.8	30.2	104,287.6

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

When compared on a field-by-field basis, some of the estimates of CRC are greater and some are less than the estimates of Netherland, Sewell & Associates, Inc. (NSAI). However, in our opinion the estimates shown herein of CRC's reserves are reasonable when aggregated at the proved level and have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). Additionally, these estimates are within the recommended 10 percent tolerance threshold set forth in the SPE Standards. We are satisfied with the methods and procedures used by CRC in preparing the December 31, 2019, estimates of reserves, and we saw nothing of an unusual nature that would cause us to take exception with the estimates, in the aggregate, as prepared by CRC.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves included herein have not been adjusted for risk. CRC's estimates do not include probable or possible reserves that may exist for these properties.

Oil, NGL, and gas prices were used only to confirm economic producibility and determine economic limits for the properties. Prices used by CRC are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2019. For oil and NGL volumes, the average Brent spot price of $63.15 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.58 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $61.57 per barrel of oil, $18.31 per barrel of NGL, and $3.05 per MCF of gas.

Costs were used only to confirm economic producibility and determine economic limits for the properties. Operating costs used by CRC are based on historical operating expense records. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. Headquarters general and administrative overhead expenses of CRC are included to the extent that they are covered under joint operating agreements for the operated properties. Capital costs used by CRC are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Abandonment costs used are CRC's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Operating, capital, and abandonment costs are not escalated for inflation.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, estimates of CRC and NSAI are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by CRC, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts used to confirm economic producibility and determine economic limits for the properties. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing these estimates.

It should be understood that our audit does not constitute a complete reserves study of the audited oil and gas properties. Our audit consisted primarily of substantive testing, wherein we conducted a detailed review of all properties. In the conduct of our audit, we have not independently verified the accuracy and completeness of information and data furnished by CRC with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of our examination something came to our attention that brought into question the validity or sufficiency of any such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data. Our audit did not include a review of CRC's overall reserves management processes and practices.

We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to establish the conclusions set forth herein. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Supporting data documenting this audit, along with data provided by CRC, are on file in our office. The technical persons primarily responsible for conducting this audit meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. C. Ashley Smith, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2006 and has over 5 years of prior industry experience. Mike K. Norton, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1989 and has over 10 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ C. Ashley Smith	By: /s/ Mike K. Norton
C. Ashley Smith, P.E. 100560	Mike K. Norton, P.G. 441
Vice President	Senior Vice President
Date Signed: February 12, 2020	Date Signed: February 12, 2020

CAS:MSS