

PROSPECTUS



California Resources Corporation

**Offer to Exchange up to
 \$1,000,000,000 Principal Amount Outstanding of 5% Senior Notes due 2020,
 \$1,750,000,000 Principal Amount Outstanding of 5 1/2% Senior Notes due 2021, and
 \$2,250,000,000 Principal Amount Outstanding of 6% Senior Notes due 2024
 That Have Not Been Registered Under
 The Securities Act of 1933**

**For
 \$1,000,000,000 Principal Amount Outstanding of 5% Senior Notes due 2020,
 \$1,750,000,000 Principal Amount Outstanding of 5 1/2% Senior Notes due 2021, and
 \$2,250,000,000 Principal Amount Outstanding of 6% Senior Notes due 2024
 That Have Been Registered Under
 The Securities Act of 1933**

**This Exchange Offer will expire at 5:00 p.m.,
 New York City time, on April 28, 2015, unless extended.**

California Resources Corporation is offering to exchange registered 5% Senior Notes due 2020 (the “2020 exchange notes”), 5 1/2% Senior Notes due 2021 (the “2021 exchange notes”) and 6% Senior Notes due 2024 (the “2024 exchange notes”) or collectively, the “exchange notes,” for any and all of the relevant series of its unregistered 5% Senior Notes due 2020 (the “2020 original notes”), 5 1/2% Senior Notes due 2021 (the “2021 original notes”) and 6% Senior Notes due 2024 (the “2024 original notes”), or collectively, the “original notes,” that were issued pursuant to a private placement on October 1, 2014. We refer to the original notes and the exchange notes together in this prospectus as the “Notes” or “notes.” We refer to the offer to exchange the 2020 exchange notes for the 2020 original notes, the offer to exchange the 2021 exchange notes for the 2021 original notes, and the offer to exchange the 2024 exchange notes for the 2024 original notes collectively as the “exchange offer.” The terms of the exchange notes are substantially identical to the relevant series of original notes except the exchange notes are registered under the Securities Act of 1933, as amended (the “Securities Act”), and the transfer restrictions and registration rights, and related special interest provisions, applicable to the original notes will not apply to the exchange notes. The exchange notes will represent the same debt as the relevant series of original notes, and we will issue the exchange notes under the same indenture used in issuing the original notes.

Terms of the exchange offer:

- The exchange offer expires at 5:00 p.m., New York City time, on April 28, 2015, unless we extend it.
- The exchange offer is subject to customary conditions, which we may waive.

- We will exchange all outstanding original notes that are validly tendered and not withdrawn prior to the expiration of the exchange offer for an equal principal amount of the relevant series of exchange notes. All interest due and payable on the original notes will become due and payable on the same terms under the relevant series of exchange notes.
- You may withdraw your tender of original notes at any time prior to the expiration of the exchange offer.
- If you fail to tender your original notes, you will continue to hold unregistered, restricted securities, and your ability to transfer them

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- We believe that the exchange of original notes for exchange notes will not be a taxable event for U.S. federal income tax purposes, but you should see the discussion under the caption “Certain United States Federal Income Tax Considerations” for more information.
- We will not receive any proceeds from the exchange offer.

See “Risk Factors” beginning on page 9 for a discussion of risks you should consider in connection with the exchange offer and the exchange notes.

Each broker-dealer that receives exchange notes pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of exchange notes. The letter of transmittal states that by so acknowledging and by delivering a prospectus, such broker-dealer will not be deemed to admit that it is an “underwriter” within the meaning of the Securities Act. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of the exchange notes received in exchange for original notes where such original notes were acquired by such broker-dealer as a result of market-making activities or other trading activities. Until the earlier of (i) September 27, 2015 and (ii) the date on which broker-dealers are no longer required to deliver a prospectus in connection with the market-making or other trading activities, all dealers that effect transactions in the exchange notes, whether or not participating in this exchange offer, may be required to deliver a prospectus. This is in addition to the dealers’ obligation to deliver a prospectus when acting as underwriters with respect to their unsold allotments or subscriptions. We have agreed that, at any time before September 27, 2015 (or earlier as provided in the foregoing sentence), we will make this prospectus available to any broker-dealer for use in connection with any such resale. See “The Exchange Offer—Purpose and Effects of the Exchange Offer” and “Plan of Distribution.”

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

You should read this entire document and the accompanying letter of transmittal and related documents and any amendments or supplements carefully before making your decision to participate in the exchange offer.

The date of this prospectus is March 31, 2015.

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YOU SHOULD RELY ONLY ON THE INFORMATION CONTAINED IN THIS PROSPECTUS AND IN THE ACCOMPANYING LETTER OF TRANSMITTAL. WE HAVE NOT AUTHORIZED ANYONE TO PROVIDE YOU WITH ANY OTHER OR DIFFERENT INFORMATION. IF YOU RECEIVE ANY UNAUTHORIZED INFORMATION, YOU MUST NOT RELY ON IT. THIS PROSPECTUS MAY ONLY BE USED WHERE IT IS LEGAL TO EXCHANGE THE ORIGINAL NOTES FOR THE EXCHANGE NOTES, AND THIS PROSPECTUS IS NOT AN OFFER TO EXCHANGE OR A SOLICITATION TO EXCHANGE THE ORIGINAL NOTES FOR THE EXCHANGE NOTES IN ANY JURISDICTION WHERE AN OFFER OR EXCHANGE WOULD BE UNLAWFUL. YOU SHOULD ASSUME THAT THE INFORMATION CONTAINED IN THIS PROSPECTUS IS ACCURATE ONLY AS OF THE DATE OF THIS PROSPECTUS.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

Any forward-looking statement in which we, or our management, express an expectation or belief as to future results, is made in good faith and believed to have a reasonable basis. However, there can be no assurance that the statement of expectation or belief will result or be achieved or accomplished. Taking this into account, the following are identified as important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by, or on behalf of, our company:

- commodity pricing;
- vulnerability to economic downturns and adverse developments in our business due to our debt;
- insufficiency of our operating cash flow to fund planned capital investments;
- inability to implement our capital investment program profitably or at all;
- compliance with regulations or changes in regulations and the ability to obtain government permits and approvals;
- uncertainties associated with drilling for and producing oil and natural gas;
- tax law changes;
- competition for oilfield equipment, services, qualified personnel and acquisitions;
- the subjective nature of estimates of proved reserves and related future net cash flows;
- concentration of operations in a single geographic area;
- restrictions on our ability to obtain, use, manage or dispose of water;

- inability to drill identified locations when planned or at all;
- concerns about climate change and other air quality issues;
- risks related to our acquisition activities;

- catastrophic events for which we may be uninsured or underinsured;
- cyber attacks;
- operational issues that restrict market access; and
- uncertainties related to the Spin-off, the agreements related thereto and the anticipated effects of restructuring or reorganizing our business.

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

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

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

NOTICE TO NEW HAMPSHIRE RESIDENTS ONLY

NEITHER THE FACT THAT A REGISTRATION STATEMENT OR AN APPLICATION FOR A LICENSE HAS BEEN FILED UNDER CHAPTER 421-B OF THE NEW HAMPSHIRE REVISED STATUTES ("RSA") WITH THE STATE OF NEW HAMPSHIRE NOR THE FACT THAT A SECURITY IS EFFECTIVELY REGISTERED OR A PERSON IS LICENSED IN THE STATE OF NEW HAMPSHIRE CONSTITUTES A FINDING BY THE SECRETARY OF STATE OF NEW HAMPSHIRE THAT ANY DOCUMENT FILED UNDER RSA 421-B IS TRUE, COMPLETE AND NOT MISLEADING. NEITHER ANY SUCH FACT NOR THE FACT THAT AN EXCEPTION OR EXEMPTION IS AVAILABLE FOR A SECURITY OR A TRANSACTION MEANS THE SECRETARY OF STATE HAS PASSED IN ANY WAY UPON THE MERITS OR QUALIFICATIONS OF, OR RECOMMENDED OR GIVEN APPROVAL TO, ANY PERSON, SECURITY OR TRANSACTION. IT IS UNLAWFUL TO MAKE OR CAUSE TO BE MADE, TO ANY PROSPECTIVE PURCHASER, CUSTOMER OR CLIENT, ANY REPRESENTATION INCONSISTENT WITH THE PROVISIONS OF THIS PARAGRAPH.

INDUSTRY AND MARKET DATA

The market data and certain other statistical information used throughout this prospectus includes industry data and forecasts that are based on independent industry publications, government publications or other published independent sources. Some data is also based on our good faith estimates. Although we believe these third-party sources are reliable as of their respective dates, we have not independently verified the accuracy or completeness of this information. The industry in which we operate is subject to a high degree of uncertainty and risk due to a variety of factors, including those described in the section of this prospectus entitled "Risk Factors." These and other factors could cause results to differ materially from those expressed in these publications.

ABOUT THIS PROSPECTUS

We have filed a registration statement on Form S-4 with respect to the exchange notes with the SEC. This prospectus, which forms part of such registration statement, does not contain all the information included in the registration statement, including its exhibits and schedules. For further information about us and the notes described in this prospectus, you should refer to the registration statement and its exhibits and schedules. Statements we make in this prospectus about certain contracts or other documents are not necessarily complete.

When we make such statements, we refer you to the copies of the contracts or documents that are filed as exhibits to the registration statement, because those statements are qualified in all respects by reference to those exhibits. The registration statement, including the exhibits and schedules, is available at the SEC's website at www.sec.gov.

We have not authorized anyone to give any information or to make any representations concerning the exchange offer except that which is in this prospectus. If anyone gives or makes any other information or representation, you should not rely on it. This prospectus is not an offer to sell or a solicitation of an offer to buy securities in any circumstances in which the offer or solicitation is unlawful. You should not interpret the delivery of this prospectus, or any sale of securities, as an indication that there has been no change in our affairs since the date of this prospectus. You should also be aware that information in this prospectus may change after its date.

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. Our SEC filings are available over the Internet at the SEC's website at www.sec.gov. You may also read and copy any document that we file at the SEC's public reference room at 100 F. Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for more information on the public reference room and its copy charges.

You may also obtain documents referenced in this prospectus without charge by writing or telephoning us at the following address and telephone number:

California Resources Corporation
Attention: Investor Relations
10889 Wilshire Blvd.
Los Angeles, California 90024
Phone: (888) 848-4754

You will not be charged for any of these documents that you request. In order to ensure timely delivery of the documents, any request should be made at least five days prior to the Expiration Date (as defined herein).

PROSPECTUS SUMMARY

This summary highlights selected information about us and the exchange offer contained elsewhere in this prospectus. This summary is not complete and does not contain all of the information that may be important to you or that you should consider before participating in the exchange offer or making an investment in the exchange notes. To understand the exchange offer fully and for a more complete description of the legal terms of the exchange notes, you should carefully read this entire prospectus, particularly the risks of investing in the exchange notes discussed under "Risk Factors," "Cautionary Note Regarding Forward-Looking Statements," "Management's Discussion and Analysis of Financial Condition and Results of Operations," our audited and unaudited historical consolidated and combined financial statements and the notes thereto included elsewhere in this prospectus and the accompanying letter of transmittal.

Except when the context otherwise requires or where otherwise indicated, (1) all references to "CRC," the "Company," "we," "us" and "our" refer to California Resources Corporation and its subsidiaries and (2) all references to "Occidental" refer to Occidental Petroleum Corporation, our former parent, and its subsidiaries. Except as otherwise indicated or unless the context otherwise requires, references in this prospectus to drilling locations are to "gross" drilling locations and exclude our prospective resource drilling locations.

Our Company

We are an independent oil and natural gas exploration and production company operating properties exclusively within the State of California. Our business is focused on conventional and unconventional assets, exclusively in California, which can generate positive cash flow throughout the oil and natural gas price cycle and have the capacity to provide significant production and cash flow growth in a higher price environment. We are the largest oil and gas producer in California on a gross operated basis and we believe we have established the largest privately-held mineral acreage position in the state, consisting of approximately 2.4 million net acres spanning the state's four major oil and natural gas basins. We produced on average approximately 159 MBoe/d net for the year ended December 31, 2014. As of December 31, 2014, we had proved reserves of 768 MMBoe, with approximately 72% proved developed. Oil represented 72% of our proved reserves. Our aggregate PV-10 value was \$16.1 billion. For an explanation of the non-GAAP financial measure PV-10 and a reconciliation of PV-10 to Standardized Measure, the most directly comparable GAAP financial measure, see "Our Reserves and Production Information" section below. Our current drilling inventory comprises a diversified portfolio of oil and natural gas locations, which allows us to target drilling projects that are economically viable even in a low commodity price environment.

On November 30, 2014, our company was separated from Occidental in a series of transactions (the consummation of such transactions, the “Spin-off”). Prior to the Spin-off, we were an indirect, wholly-owned subsidiary of Occidental. In connection with the Spin-off, Occidental transferred its California oil and gas exploration and production operations and related assets, liabilities and obligations to us. On November 30, 2014, Occidental distributed shares of our common stock pro rata to Occidental stockholders and we became an independent, publicly traded company. Occidental retained approximately 18.5% of our outstanding shares of common stock, which it has stated it intends to divest within 18 months after November 30, 2014.

Our principal executive offices are located at 10889 Wilshire Boulevard, Los Angeles, California 90024. Our telephone number is (888) 848-4754. Our website is located at www.crc.com. Information on our website or any other website is not incorporated by reference herein and does not constitute a part of this prospectus.

Summary of the Exchange Offer

On October 1, 2014, we completed an unregistered offering of the original notes. As part of that offering, we entered into a registration rights agreement with the initial purchasers of the original notes, which we refer to as the registration rights agreement, in which we agreed, among other things, to offer to exchange the original notes for the exchange notes. The following is a summary of the principal terms of the exchange offer. A more detailed description is contained in the section of this prospectus titled “The Exchange Offer.”

Original Notes	5% senior notes due 2020 (“2020 original notes”), 5½% senior notes due 2021 (“2021 original notes”), and 6% senior notes due 2024 (“2024 original notes”), which were issued by California Resources Corporation in a private placement on October 1, 2014.
Exchange Notes	5% senior notes due 2020 (“2020 exchange notes”), 5½% senior notes due 2021 (“2021 exchange notes”), and 6% senior notes due 2024 (“2024 exchange notes”), issued by California Resources Corporation. The terms of the exchange notes are substantially identical to the related original notes except the exchange notes are registered under the Securities Act of 1933, as amended (the “Securities Act”), and the transfer restrictions and registration rights, and related special interest provisions, applicable to the original notes will not apply to the exchange notes. The exchange notes will represent the same debt as the related original notes, and we will issue the exchange notes under the same indenture used in issuing the original notes.
Exchange Offer	We are offering to exchange up to \$5.0 billion in aggregate principal amount of our exchange notes that have been registered under the Securities Act for an equal aggregate principal amount of our original notes. You may exchange your 2020 original notes for 2020 exchange notes, your 2021 original notes for 2021 exchange notes and your 2024 original notes for 2024 exchange notes.
Expiration Date	The exchange offer will expire at 5:00 p.m., New York City time, on April 28, 2015, which we refer to as the “Expiration Date,” unless we decide to extend it or terminate it early. We do not currently intend to extend the exchange offer. We will issue the exchange notes on the Expiration Date or promptly after that date. A tender of original notes pursuant to this exchange offer may be withdrawn at any time on or prior to the Expiration Date if we receive a valid written withdrawal request before the expiration of the exchange offer.
Conditions to the Exchange Offer	The exchange offer is subject to customary conditions which include, among other things, the absence of any applicable law or any applicable

interpretation of the staff of the Securities and Exchange Commission ("SEC") which, in our reasonable judgment, would materially impair our ability to proceed with the exchange offer. The exchange offer is not conditioned upon any minimum principal amount of original notes being submitted for exchange. Please see "The Exchange Offer—Conditions to the Exchange Offer" for more information regarding the conditions to the exchange offer.

Procedures for Tendering Original Notes

All of the original notes are held in book-entry form through the facilities of the Depository Trust Company ("DTC"). To participate in the exchange offer, you must follow the Automated Tender Offer Program ("ATOP") procedures established by DTC for tendering original notes held in book-entry form. The ATOP procedures required that the exchange agent receive, prior to the expiration date of the exchange offer, a computer-generated message known as an "agent's message" that is transmitted through ATOP and that DTC confirm that:

- DTC has received instructions to exchange your original notes; and
- you agree to be bound by the terms of the letter of transmittal.

By using the ATOP procedures and thus binding yourself to the terms of the letter of transmittal, you will represent to us that, among other things:

- you are acquiring exchange notes in the ordinary course of your business;
- you have no arrangement or understanding with any person or entity to participate in a distribution of the exchange notes;
- you are not our "affiliate" as defined in Rule 405 of the Securities Act;
- if you are not a broker-dealer, that you are not engaged in, and do not intend to engage in, the distribution of the exchange notes; and
- if you are a broker-dealer that will receive exchange notes for your own account in exchange for original notes that were acquired by you as a result of market-making or other trading activities, that you will deliver a prospectus in connection with any resale of such exchange notes.

If you are a broker-dealer, you may not participate in the exchange offer as to any original notes you purchased directly from us.

Special Procedures for Beneficial Owners

Beneficial owners of original notes should contact their broker, dealer, commercial bank, trust company or other nominee for assistance in tendering their original notes in the exchange offer. If you wish to tender on your own behalf, you must, before instructing such nominee to tender and deliver original notes on your behalf, either arrange to have your original notes registered in your name or obtain a properly completed bond power from the registered holder. The transfer of registered ownership may take a long time.

Guaranteed Delivery Procedures

None.

Acceptance of Original Notes and Delivery of Exchange Notes	If you comply with the procedures of the exchange offer we will accept for exchange any and all original notes that are properly tendered in the exchange offer and not validly withdrawn prior to the Expiration Date. The exchange notes will be delivered promptly after the Expiration Date.
Withdrawal; Non-Acceptance	You may withdraw any original notes tendered in the exchange offer by sending a notice of withdrawal to the exchange agent using the ATOP procedures at any time prior to the Expiration Date. Any withdrawn original notes will be credited to the tendering holders' account at DTC. For further information regarding the withdrawal of tendered original notes, please see "The Exchange Offer—Withdrawal of Tenders." If any tendered original notes are not accepted for exchange because they do not comply with the procedures set forth in this prospectus and the accompanying letter of transmittal, or because of our withdrawal of the exchange offer, the occurrence of certain other events set forth herein or otherwise, such unaccepted original notes will be returned, without expense, to the tendering holder promptly after the Expiration Date or our withdrawal of the exchange offer. For further information regarding conditions to the exchange offer, please see "The Exchange Offer—Conditions to the Exchange Offer."
Accounting Treatment	We will not recognize a gain or loss for accounting purposes as a result of the exchange offer.
Certain United States Federal Income Tax Considerations	The exchange of original notes for exchange notes in the exchange offer will not be a taxable event for U.S. federal income tax purposes. Please see "Certain United States Federal Income Tax Considerations" for more information regarding the tax consequences to you of the exchange offer.
Use of Proceeds	The issuance of the exchange notes will not provide us with any proceeds. We are making this exchange offer solely to satisfy our obligations under the registration rights agreement we entered into with the initial purchasers of the original notes.
Fees and Expenses	We will pay all expenses incident to the exchange offer. Please see "The Exchange Offer—Fees and Expenses" for more information regarding payment of fees and expenses related to the exchange offer.
Exchange Agent; Paying Agent and Registrar	Wells Fargo Bank, National Association is serving as the exchange agent in connection with the exchange offer and will initially act as paying agent and registrar for the exchange notes. Wells Fargo Bank, National Association also serves as trustee under the indenture governing the notes. You can find the address and telephone number of the exchange agent elsewhere in this prospectus under the caption "The Exchange Offer—Exchange Agent."
Not Exchanging Your Original Notes	If you do not exchange your original notes in this exchange offer, you will continue to hold unregistered original notes and you will

no longer be entitled to registration rights or the special interest provisions related thereto. See “The Exchange Offer—Consequences of Failure to Exchange.” In addition, while your original notes will continue to accrue interest until maturity in accordance with the terms of the original notes, you will not be able to resell, offer to resell or otherwise transfer your original notes unless you do so in a transaction exempt from the registration requirements of the Securities Act and applicable state securities laws or unless we register the offer and resale of your original notes under the Securities Act. Following the exchange offer, we will be under no obligation to, and we do not intend to, register your original notes. As a result of such restrictions, and the availability of registered exchange notes, your original notes are likely to be a much less liquid security than before.

Additional Documentation; Further Information; Assistance

Any questions of requests for assistance or additional documentation regarding the exchange offer may be directed to the exchange agent.

The Exchange Notes

The terms of the exchange notes and those of the outstanding original notes are substantially identical, except that the exchange notes are registered under the Securities Act, and the transfer restrictions and registration rights, and related special interest provisions, applicable to the original notes will not apply to the exchange notes. The exchange notes represent the same debt as the original notes for which they are being exchanged. Both the original notes and the exchange notes are governed by the same indenture. The brief summary below describes the principal terms of the exchange notes. Some of the terms and conditions described below are subject to important limitations and exceptions. The “Description of Exchange Notes” section of this prospectus contains a more detailed description of the terms and conditions of the exchange notes.

Issuer	California Resources Corporation.
Exchange Notes Offered	We are offering \$5.0 billion aggregate principal amount of notes registered under the Securities Act of the following series: • \$1,000,000,000 aggregate principal amount of 5% senior notes due 2020; • \$1,750,000,000 aggregate principal amount of 5 1/2% senior notes due 2021; and • \$2,250,000,000 aggregate principal amount of 6% senior notes due 2024.
Maturity Date	The 2020 exchange notes will mature on January 15, 2020, the 2021 exchange notes will mature on September 15, 2021 and the 2024 exchange notes will mature on November 15, 2024.
Interest	The 2020 exchange notes will bear interest at a rate of 5% per annum, the 2021 exchange notes will bear interest at a rate of 5 1/2% per annum and the 2024 exchange notes will bear interest at a rate of 6% per annum.
Interest Payment Dates	Interest on the 2020 exchange notes will be paid semi-annually in arrears on January 15 and July 15 of each year, beginning on July 15, 2015. Interest on

	the 2021 exchange notes will be paid semi-annually in arrears on March 15 and September 15 of each year, beginning on March 15, 2015. Interest on the 2024 exchange notes will be paid semi-annually in arrears on May 15 and November 15 of each year, beginning on May 15, 2015.
Guarantees	The exchange notes will initially be fully and unconditionally guaranteed on a senior unsecured basis by all of our material subsidiaries. Please see “Description of Exchange Notes—Certain Covenants—Guarantees” and “Description of Exchange Notes—Guarantees.”
Ranking	The exchange notes will be our general senior unsecured obligations and will rank: • <i>pari passu</i> in right of payment with any of our senior unsecured indebtedness, including indebtedness incurred under our Revolving Credit Facility and our Term Loan

	Facility (each as defined in “Management’s Discussion and Analysis of Financial Condition and Results of Operations-Liquidity and Capital Resources-Credit Facilities”); • effectively junior to any of our future secured indebtedness and other obligations to the extent of the value of the collateral securing such indebtedness and obligations; • structurally subordinated to any indebtedness and other liabilities (other than indebtedness and liabilities owed to us) of our subsidiaries that do not guarantee the exchange notes; and • senior in right of payment to any of our future subordinated indebtedness. As of December 31, 2014, we and our subsidiaries had approximately \$6.36 billion of consolidated indebtedness, comprised of \$5.0 billion of original notes, \$1.0 billion of borrowings outstanding under our Term Loan Facility and \$360 million of borrowings outstanding under our Revolving Credit Facility. We currently have the ability to incur total net borrowings of up to \$1.25 billion under our Revolving Credit Facility. In addition, as of December 31, 2014 we had letters of credit in an aggregate amount of \$25 million that were issued to support ordinary course marketing, regulatory and other matters under uncommitted letter of credit lines. Non-guarantor subsidiaries represented less than 1% of our total assets and had no indebtedness as of December 31, 2014, and represented less than 1% of revenues for the twelve months ended December 31, 2014.
Optional Redemption	We may redeem the exchange notes of each series, in whole or in part, at any time and from time to time, at our option at the applicable redemption prices set forth under “Description of Exchange Notes—Optional Redemption.”
Offer to Repurchase Following Change of Control	If we experience a change of control (as defined in the indenture governing the exchange notes) accompanied by a ratings decline with respect to a series of exchange notes, we must offer to repurchase the exchange notes of such series at 101% of their principal amount, plus accrued and unpaid interest. See “Description of Exchange Notes—Change of Control.”

Certain Covenants	The indenture governing the exchange notes, among other things, restricts our ability, and our restricted subsidiaries' ability, to incur debt secured by liens. These covenants will also restrict our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. These and other covenants that are contained in the indenture are subject to important exceptions and qualifications, which are described under "Description of Exchange Notes."
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No Prior Market	The exchange notes will be new securities for which there is currently no market. Although the initial purchasers have informed us that they intend to make a market in the exchange notes, they are not obligated to do so and may discontinue market-making at any time without notice. Accordingly, we cannot assure you that a liquid market for the exchange notes will develop or be maintained.
Book-Entry Form	The exchange notes will be issued in book-entry form and will be represented by one or more global securities registered in the name of Cede & Co., as nominee for The Depository Trust Company, or DTC. Beneficial interests in the exchange notes will be evidenced by, and transfers will be effected only through, records maintained by DTC participants.
Form and Denomination	The exchange notes will be issuable in minimum denominations of \$2,000 and integral multiples of \$1,000 in excess thereof.
Risk Factors	You should consider carefully all the information included and incorporated by reference in this prospectus and, in particular, you should evaluate the specific factors set forth under "Risk Factors" in this prospectus, before deciding whether to participate in the exchange offer.

RISK FACTORS

You should carefully consider the information included in this prospectus, including the matters addressed under "Cautionary Note Regarding Forward-Looking Statements," and the following risks before deciding to exchange your original notes for exchange notes pursuant to this exchange offer.

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

operations.

Risks Related to Our Business

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

Our financial results, financial condition, cash flow and rate of growth correlate closely to the prices we obtain for our products. Recently, global energy commodity prices have declined significantly. For example, Brent crude prices declined from over \$115 per barrel in June 2014 to below \$47 per barrel in January 2015. In a declining price environment we may incur costs to terminate drilling rig contracts, and may be required to write-down property values, such as we did in recent months. Product prices can fluctuate widely and are affected by a variety of factors, including changes in consumption patterns, global and local (particularly for natural gas) economic conditions, the actions of OPEC and other oil and natural gas producing countries, inventory levels, actual or threatened production disruptions, currency exchange rates, worldwide drilling and exploration activities, the effects of conservation, weather, geophysical and technical limitations, refining and processing disruptions, transportation bottlenecks and other matters affecting the supply and demand dynamics of oil, natural gas and NGLs, and the effect of changes in market perceptions. These and other factors make it impossible to predict realized prices reliably. In addition, any significant increase in transportation infrastructure that increases the importation of crude oil to California from other parts of the country could negatively impact the price we receive for our crude oil.

Any sustained periods of low prices for oil and natural gas may materially and adversely affect our financial position, the quantities of natural gas and oil reserves that we can economically produce, our cash flow available for capital investments and our ability to access funds under our revolving credit facility and through the capital markets.

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

As of December 31, 2014, we had \$6.36 billion of consolidated indebtedness, comprising \$5.0 billion of senior notes, \$1.0 billion of borrowings outstanding under our Term Loan Facility and \$360 million of borrowings outstanding under our Revolving Credit Facility, and we had the ability to incur \$1.64 billion of additional borrowings under our Revolving Credit Facility, which has effectively been reduced under the first amendment to our credit facilities discussed in “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources”. As of December 31, 2014, we had letters of credit in an aggregate amount of approximately \$25 million that were issued to support ordinary course marketing, regulatory and other matters. In addition, the indenture relating to the notes and the Credit Facilities (as defined in “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources-Credit Facilities”) permits us to incur certain defined obligations, unrestricted by debt incurrence or lien covenants, or that do not constitute indebtedness (as defined in “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facilities”).

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

Our level of indebtedness will have several important effects on our future operations, including, without limitation:

- increasing our vulnerability to adverse changes in our business and to general economic and industry conditions, and putting us at a disadvantage against other competitors that have lower fixed obligations and more cash flow to devote to their businesses;
- limiting our ability to obtain additional financing for working capital, capital investments, general corporate and other purposes; and

- limiting our flexibility in operating our business and preventing us from engaging in certain transactions that might otherwise be beneficial to us.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional equity on terms that may be unattractive if it may be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness. Any of these factors could result in a material adverse effect on our business, financial condition, results of operations, cash flow and ability to satisfy our obligations under the notes.

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

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital investments for the development and exploration of oil and gas reserves. We have developed a multi-year capital investment program to execute our strategy. We invested approximately \$2.1 billion of capital on development and exploration activities during the year ended December 31, 2014, funded by our operating cash flow of \$2.4 billion. Under our 2015 capital budget, we plan to invest approximately \$420 million for development and exploration activities.

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

We intend to finance our future capital investments, other than any significant acquisitions, primarily through cash flow from operations and, if necessary, through borrowings under our Revolving Credit Facility or the issuance of debt or equity securities. We may not generate sufficient cash flow to fund our growth plans or to generate acceptable returns. Additional financing may not be available on acceptable terms or at all if there is not market demand or if our lenders refuse to exercise their discretion to expand our existing credit. In the event additional capital is needed and unavailable, we may curtail drilling, development and other activities or be forced to sell assets on an unfavorable basis.

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

Our operations are subject to complex and stringent federal, state, local and other laws and regulations relating to the exploration and development of our properties, the production, transportation and sale of our products, and the services we provide. See “Business—Regulation of the Oil and Natural Gas Industry” for a description of the laws and regulations that affect our business. To operate in compliance with these laws and regulations, we must obtain and maintain permits, approvals and certificates from federal, state and local governmental authorities. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and/or criminal fines and penalties and liability for non-compliance, costs of corrective action, cleanup or restoration, compensation for personal injury, property damage or other losses, and the imposition of injunctive or declaratory relief restricting or limiting our operations. Under certain environmental laws and regulations, we could be subject to strict or joint and several liability for the removal or remediation of contamination, including on properties over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

Costs of compliance may increase or operational delays or restrictions may occur as existing laws and regulations are revised or reinterpreted, or as new laws and regulations become applicable to our operations. Certain government agencies have adopted or proposed new or more stringent requirements for permitting, well construction, public disclosure or environmental review of, or restrictions on, certain oil and gas operations, including drilling, well stimulation, enhanced production techniques or fluid disposal. Such new requirements or restrictions or resulting litigation could result in potentially significant added costs to comply, delay or curtail our exploration, development, or production activities, and preclude us from drilling or stimulating wells, which could impair our expected production growth over the longer term. For example, in 2013, California adopted SB 4, which mandated further regulation of certain well stimulation techniques, including hydraulic fracturing.

The implementation of interim well stimulation regulations under SB 4 in 2014 delayed certain operations, and California’s implementation of final SB 4 regulations and associated studies and reports may increase costs and cause additional delays. In addition, certain local governments have proposed or adopted ordinances that purport, within their jurisdictions, to regulate certain drilling activities in general, or well stimulation or completion activities in particular, including hydraulic fracturing, or to ban such activities outright.

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.

Exploration is inherently risky and its results are unpredictable. The results of our exploratory drilling in new or emerging plays are more uncertain than drilling results in areas that are developed and have established production, and we may increase the proportion of our drilling in new or emerging plays over time. We may not find commercial amounts of oil or natural gas, in which case the value of our undeveloped acreage may decline and could be impaired.

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

Tax law changes may adversely affect our operations.

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

In addition, President Obama’s budget proposal for fiscal year 2016 recommended the elimination of certain federal income tax preferences currently available to oil and gas exploration and production companies, all of which could harm us. These changes include (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of expensing intangible drilling costs, (iii) an increase in the amortization period from two years to seven years for geological and geophysical costs paid or incurred by independent producers in connection with the exploration for, or development of, oil or natural gas and (iv) repeal of the ability to claim the domestic manufacturing deduction against income derived from the sale or exchange of oil, natural gas or primary products produced in the United States.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties.

Unless we conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our decisions to explore, develop, purchase or otherwise exploit prospects or properties will depend in part on the evaluation of geophysical, geologic, engineering, production and other technical data, the analysis of which is often inconclusive or subject to varying interpretations. Our cost of drilling, completing, equipping and operating wells is also often uncertain. Overruns in budgeted investments are a common risk that can make a particular project uneconomical or less economical than forecast. We bear the risks of equipment failures, accidents, environmental hazards, adverse weather conditions, permitting or construction delays, title disputes, surface access disputes, disappointing drilling results or reservoir performance, including response to IOR or EOR efforts, and other associated risks.

We operate in a highly competitive environment for oilfield equipment, services, qualified personnel and acquisitions.

We compete for services to profitably develop our assets, to find or acquire additional reserves and to attract and retain qualified personnel. We have many competitors, some of which: (i) are larger and better funded; (ii) may be willing to accept greater risks or (iii) have special competencies. Historically, there have been periodic shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. The demand for qualified and experienced geologists, geophysicists and engineers, and for field and other personnel to drill wells, conduct field operations and construct and maintain facilities, can fluctuate significantly, often in correlation with commodity prices, causing periodic shortages which may increase costs for such services. Finally, competition for reserves can make it more difficult to find attractive investment opportunities or require delay of reserve replacement efforts.

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

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

The reserves information included in this prospectus represents estimates prepared by internal engineers. The procedures and methods used to estimate our reserves by these internal engineers were reviewed by independent petroleum consultants; however, no audit of estimated reserve volumes was conducted by these consultants. Reserves estimation is a partially subjective process of estimating accumulations of oil and natural gas. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variables and assumptions, including:

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

- future workover and remedial costs.

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

We currently expect improved recovery, extensions and discoveries to be our main sources for reserve additions, but factors such as geology, government regulations and permits and the effectiveness of development plans are partially or fully outside management’s control and could cause unforeseen results.

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

Our operations are geographically concentrated exclusively in California. Because of this geographic concentration, the success and profitability of our operations may be disproportionately exposed to the effect of regional events. These include, among others, fluctuations in the prices of crude oil and natural gas produced from wells in the region, changes in state or regional laws and regulations affecting our operations, and other regional supply and demand factors, including gathering, pipeline and rail transportation capacity constraints, available rigs, equipment, oil field services, supplies, labor and infrastructure capacity. The concentration of our operations in California also increases exposure to unexpected events that may occur in this region such as natural disasters, 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 and prevent development of lease inventory before expiration. Any of the risks described above could have a material adverse effect on our financial condition, results of operations and cash flows.

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

Water is an essential component of our operations. Approximately 90% of the fluids we produce are brackish waters, unsuitable for agricultural use, that need to be managed, recycled or disposed. We treat and re-use this water for a substantial portion of our needs related to activities such as steamflooding, waterflooding, pressure management, well completion and stimulation, including hydraulic fracturing, and we provide water for agricultural use in certain areas. We also use supplied water from various local and regional sources. Some of our fields are more dependent on supplied water to support operations like steam injection. Due to severe drought in California, some local and regional water districts and the state government are implementing policies or regulations that restrict water usage and increase the cost of water.

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

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

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

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

We have specifically identified locations for scheduled drilling over the next several years. These drilling locations represent a significant part of our long-term growth strategy. Our ability to profitably drill and develop these locations depends on a number of variables, including crude oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals, available transportation capacity and other factors. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling or development of these projects. We view the risk profile for our exploration drilling locations and our prospective resource drilling locations as being higher than for our other drilling locations due to relatively less available geologic and production data and drilling history, in particular with respect to our prospective resource locations, which are in unproven geologic plays. We make assumptions about the consistency and accuracy of data when we identify these locations that may prove inaccurate. We cannot guarantee that these prospective drilling locations or any other drilling locations we have identified will ever be drilled or if we will be able to produce crude oil or natural gas from these drilling locations. In addition, some of our

leases could expire if we do not establish production in the leased acreage. The combined net acreage covered by leases expiring in the next three years represents 23% of our total net undeveloped acreage at December 31, 2014. Our actual drilling activities may materially differ from those presently identified.

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

The Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act"), enacted in 2010, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, like us, that participate in that market. The Dodd-Frank Act requires the Commodities and Futures Trading Commission ("CFTC") and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented, and it is not possible at this time to predict when this will be accomplished.

The CFTC is authorized to set position limits for certain futures contracts in designated physical commodities and for economically equivalent options and swaps. In November 2013, the CFTC proposed rules that would place limits on positions in certain futures and equivalent swap contracts for, or linked to, certain physical commodities; subject to exceptions for certain bona fide hedging transactions. We do not know when the CFTC will finalize these regulations; therefore, the impact of those provisions on us is currently uncertain.

The CFTC designated certain interest rate swaps and credit default swaps for mandatory clearing and exchange trading. In addition, the Dodd-Frank Act requires that regulators establish margin rules for uncleared swaps. The application of such requirements may indirectly change the cost and availability of the swaps that we may use for hedging.

The Dodd-Frank Act and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter or reduce our ability to monetize or restructure derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

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

To the extent that we engage in commodity-price risk-management activities to protect our cash flows from commodity-price declines, we may be prevented from realizing the full benefits of price increases above the levels stated in the derivative instruments used to manage price risk. In addition, our commodity-price risk-management and trading activities may expose us to the risk of financial loss in certain circumstances, including instances in which the following occur:

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

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

Climate change, the costs that may be associated with its effects and the regulation of Greenhouse Gases ("GHGs") may affect our business in many ways, including increasing the costs to provide our products and services, and reducing demand for, and consumption of, our products and services. In addition, legislative and regulatory responses to climate change may increase our operating costs. In 2006, California adopted AB 32, which established a statewide cap on GHG emissions, including on the oil and natural gas production industry, and a "cap-and-trade" program. Since 2012, California Air Resources Board ("CARB") regulations have required us to obtain GHG emissions allowances corresponding to reported GHG emissions from operations and, starting in 2015, from the sale of certain products to customers for use in the State. In 2014, we incurred approximately \$33 million to purchase mandatory GHG emissions allowances in California, and costs of such allowances are expected to increase in the future as CARB reduces the number of available allowances, increases their targeted price and covers more operations and products in the program. In addition, other CARB regulations, state policies and proposed legislation seek to restrict or reduce the use of petroleum products in transportation fuels and electricity generation in California and require the use of renewable energy, which could increase our costs and reduce the demand for our products and services.

Federal and state regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. In addition, California air quality laws and regulations,

particularly in Southern and Central California where most of our operations are located, are in many instances more stringent than comparable federal laws and regulations. As these requirements become more stringent, we may be unable to implement them in a cost-effective manner. As a result of existing and future air quality initiatives, we could face risks of increased costs and taxes, an inability to execute projects and reduced demand for our products and services.

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

Our acquisition activities carry risks that we may: (i) not fully realize anticipated benefits due to less-than-expected reserves or production or changed circumstances, such as the deterioration of natural gas prices in recent years and oil prices in recent months; (ii) bear unexpected integration costs or experience other integration difficulties; (iii) experience share price declines based on the market’s evaluation of the activity or (iv) assume liabilities that are greater than anticipated.

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

There may be threatened, contemplated, asserted or other claims against the acquired assets related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware or for which we are unable to obtain indemnity.

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

We are not fully insured against all risks. Our oil and gas exploration and production activities, including well stimulation and completion activities, are subject to operating risks associated with drilling for and producing oil and natural gas, such as well blowouts, fires, explosions, releases or discharges of hazardous or toxic materials and industrial accidents. Other catastrophic events such as earthquakes, floods, mudslides, droughts, terrorist attacks and other events that cause operations to cease or be curtailed may negatively affect our business and the communities in which we operate. We may be unable to obtain, or may elect not to obtain, insurance for certain risks if we believe that the cost of available insurance is excessive relative to the risks presented.

Cyber attacks could significantly affect us.

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

Operational issues could restrict access to markets for the commodities we produce.

Our ability to market our production of oil, natural gas and NGLs depends on a number of factors, including the proximity of production fields to pipelines and terminal facilities, competition for capacity on such facilities, the ability of such facilities to gather, transport or process our products and regional disruptions, such as strikes and mechanical failures. If our access to markets for commodities we produce is restricted, our costs could increase and our expected production may be impaired.

Risks Related to the Spin-off

We may not realize the anticipated benefits from our separation from Occidental.

We may not realize the benefits that we anticipate from our separation from Occidental. These benefits include the following:

- enhancing our ability to grow by reinvesting substantially all of our cash flow in our business;
- enhancing growth and efficiency by enabling our management team to focus its attention on the development and execution of our business in a single state;
- enhancing our focus on, and accelerating our technical expertise in, specific reservoirs and fields in California; and
- enhancing our market recognition with investors because of our status as an industry leader in California.

We may not achieve the anticipated benefits from our separation for a variety of reasons. We may not generate sufficient cash flow to fund our long-term growth plans and to generate acceptable returns. We also may not fully realize the anticipated benefits from our separation if any of the other matters identified as risks in this “Risk Factors” section were to occur.

Our historical financial information may not be representative of the results we would have achieved as a stand-alone public company and may not be a reliable indicator of our future results.

The historical financial information included in this prospectus has been derived partly from Occidental’s accounting records and may not reflect what our financial position, results of operations or cash flows would have been had we been an independent, stand-alone entity during the periods presented or those that we will achieve in the future. Occidental did not account for us, and we were not operated, as a separate, stand-alone company or as a separate segment for the historical periods presented. The costs and expenses reflected in our historical financial information include an allocation for certain corporate functions historically provided by Occidental, including expense allocations for: (i) executive oversight, accounting, procurement, engineering, drilling, exploration, finance, internal audit, legal, risk management, tax, treasury, information technology, government relations, investor relations, public relations, financial reporting, human resources, marketing, ethics and compliance, and certain other shared services; (ii) certain employee benefits and incentives; and (iii) share-based compensation, that may be different from the comparable expenses that we would have incurred had we operated as a stand-alone company. We have allocated these expenses in our historical financial information on the basis of direct usage when

identifiable, with the remainder allocated based on estimated time spent by Occidental personnel, headcount or our relative size compared to Occidental and its subsidiaries. The costs of operating as a stand-alone public company, other than the debt-related costs, may be slightly higher than the costs reported in the 2014 historical financial statements. These estimates may not prove to be accurate. Our capital investment requirements, including acquisitions, historically have been satisfied as part of the companywide cash management practices of Occidental. Following the Spin-off, we no longer have access to Occidental’s working capital, and we may need to obtain additional financing from banks, through public offerings or private placements of debt or equity securities or other arrangements if our cash flow from operations and our existing Credit Facilities are not sufficient to fund our capital investment requirements.

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

Pursuant to agreements with Occidental, Occidental has indemnified us for certain liabilities, and we agreed to indemnify Occidental for certain liabilities, in each case for uncapped amounts, as discussed further in “Certain Relationships and Related Party Transactions—Arrangements Between Occidental and Our Company.” Indemnity payments that we may be required to provide Occidental may be significant and could negatively impact our business, particularly indemnity payments relating to our actions that could impact the tax-free nature of the Spin-off. Third parties could also seek to hold us responsible for liabilities that Occidental has agreed to retain. Further, there can be no assurance that the indemnity from Occidental will be sufficient to protect us against the full amount of such liabilities, or that Occidental will be able to fully satisfy its indemnification obligations. Moreover, even if we ultimately succeed in recovering from Occidental any amounts for which we are held liable, we may be temporarily required to bear these losses ourselves.

Our costs may increase as a result of operating as a stand-alone public company, and our management will be required to devote substantial time to complying with public company regulations.

Prior to the Spin-off, our operations were fully integrated within Occidental, and we relied on Occidental to provide certain corporate functions. As a stand-alone public company, we may incur additional expenses for executive oversight, accounting, finance, risk management, treasury, tax, financial reporting, internal audit, legal, information technology, governmental relations, public relations, investor relations, human resources, procurement, engineering, drilling, exploration, ethics and compliance, marketing and certain other services that we have not incurred historically. As part of Occidental, we were able to enjoy certain benefits from Occidental’s scale and purchasing power. As an independent, publicly traded company, we do not have similar negotiating leverage.

In addition, we are now obligated to file with the SEC annual and quarterly information and other reports, and, as a result, must ensure that we have the ability to prepare financial statements that are fully compliant with all SEC reporting requirements on a timely basis. In addition, we are now subject to other reporting and corporate governance requirements, including certain requirements of the New York Stock Exchange (the “NYSE”), and certain provisions of the Sarbanes-Oxley Act of 2002, and the regulations promulgated thereunder, which impose significant compliance obligations and costs upon us.

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

Under the Tax Sharing Agreement, we have agreed to take certain actions or refrain from taking certain actions to ensure that the Spin-off and

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

We have agreed to indemnify Occidental for (a) taxes incurred as a result of the failure of the Spin-off or certain transactions undertaken in preparation for, or in connection with, the Spin-off, to qualify as tax-free transactions under the relevant provisions of the Code, as amended, to the extent caused by (i) our breach of certain tax-related representations or covenants made in connection with the Spin-off, (ii) actions, failures to act and omissions inconsistent with such representations and covenants and (iii) certain permitted transactions, (b) our separate taxes due to capitalization of intangible drilling and

development costs, (c) any finally determined increases of our liability for separate tax items included in combined or consolidated Occidental returns, and (d) 50% of certain sales, use, transfer, real property transfer, intangible, recordation, registration, documentary, stamp and similar taxes. We also have agreed to pay 50% of any taxes arising from the Spin-off or related transactions to the extent that the tax is not attributable to the fault of either party. However, if we receive an increase in the tax basis of our depletable, depreciable or amortizable assets as a result of any such tax begin imposed, we will pay to Occidental any amount equal to any reduction in our tax liability attributable to such basis increase at the time such reduction in tax liability arises. In addition, we have agreed to indemnify Occidental and its remaining subsidiaries against claims and liabilities relating to the past operation of our business.

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

For any tax periods (or portion thereof) in which Occidental owned at least 80% of the total voting power and value of our common stock, we and our subsidiaries will be included in Occidental’s consolidated group for federal income tax purposes. In addition, we or one or more of our subsidiaries may be included in the combined, consolidated or unitary tax returns of Occidental or one or more of its subsidiaries for state or local income tax purposes. Under the Tax Sharing Agreement, for each period in which we or any of our subsidiaries are consolidated or combined with Occidental for purposes of any tax return, and with respect to which such tax return has not yet been filed, we will pay Occidental for any additional taxes payable by Occidental resulting from Occidental’s election to capitalize some or all of certain CRC intangible drilling costs. We will also be responsible for any increase in Occidental’s federal or state tax liability for any period in which we or any of our subsidiaries are combined or consolidated with Occidental if such increase results from audit adjustments attributable to our business. In addition, by virtue of Occidental’s controlling ownership and the Tax Sharing Agreement, Occidental will effectively control all of our tax decisions in connection with any consolidated, combined or unitary income tax returns in which we (or any of our subsidiaries) are included. The Tax Sharing Agreement provides that Occidental will have sole authority to respond to and conduct all tax proceedings (including tax audits) relating to us, to prepare and file all consolidated, combined or unitary income tax returns in which we are included on our behalf (including the making of any tax elections). This arrangement may result in conflicts of interest between Occidental and us. For example, under the Tax Sharing Agreement, Occidental will be able to choose to contest, compromise or settle any adjustment or deficiency proposed by the relevant taxing authority in a manner that may be beneficial to Occidental and detrimental to us. See “Certain Relationships and Related Party Transactions—Arrangements Between Occidental and Our Company—Tax Sharing Agreement.”

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

The amount of tax for which we are liable for taxable periods preceding the Spin-off may be impacted by elections Occidental makes on our behalf.

Under the Tax Sharing Agreement, Occidental will have the right to make all elections, including elections to capitalize intangible drilling costs, relevant to the determination of our tax liability for periods while we, or any of our subsidiaries, are required to file tax returns with Occidental on a consolidated or combined basis or which include pre-Spin-off periods. As a result, the amount of tax for which we are liable for taxable periods preceding the Spin-off may be impacted by elections Occidental makes on our behalf.

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

In certain circumstances, if the Spin-off is determined to be taxable for U.S. federal income tax purposes, we could incur significant liabilities

under a tax-sharing agreement between us and Occidental. Occidental has received a private letter ruling from the Internal Revenue Service ("IRS") to the effect that certain aspects of the transactions that will be undertaken in preparation for, or in connection with, the Spin-off will not cause the distribution to be taxable to Occidental or its affiliates. Occidental also received opinions from tax counsel that (i) certain transactions that will be undertaken in preparation for, or in connection with, the Spin-off will not be taxable to Occidental or its affiliates for federal income tax purposes and (ii) the Spin-off generally qualifies as a tax-free transaction under Sections 355, 361 and/or 368(a)(1)(D) of the Code. The private letter ruling relies and the opinions rely on facts, assumptions, representations and undertakings from Occidental and us regarding the past and future conduct of the companies' respective businesses and other matters. If any of these facts, assumptions, representations, or undertakings are, or become, incorrect or not otherwise satisfied, Occidental may not be able to rely on the private letter ruling or the opinions of its tax advisor and could be subject to significant tax liabilities. In addition, an opinion of counsel is not binding upon the IRS, so, notwithstanding the opinions of Occidental's tax advisor, the IRS could conclude upon

audit that the Spin-off is taxable in full or in part. The IRS may determine that the Spin-off is taxable for other reasons, including as a result of certain significant changes in the stock ownership of Occidental or us after the Spin-off. For a description of the sharing of such liabilities between Occidental and us, see "Certain Relationships and Related Party Transactions—Arrangements Between Occidental and Our Company—Tax Sharing Agreement."

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

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

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

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

The measure of insolvency for purposes of the fraudulent conveyance laws will vary depending on which jurisdiction's law is applied. Generally, however, an entity would be considered insolvent if the present fair saleable value of its assets is less than (i) the amount of its liabilities (including contingent liabilities) or (ii) the amount that will be required to pay its probable liabilities on its existing debts as they become absolute and mature. No assurance can be given as to what standard a court would apply to determine insolvency or that a court would determine that we, Occidental or any of our respective subsidiaries were solvent at the time of or after giving effect to the Spin-off, including the distribution of our common stock.

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

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

The agreements we entered into with Occidental in connection with the Spin-off, were negotiated in the context of the Spin-off while we were still a wholly-owned subsidiary of Occidental. Accordingly, during the period in which the terms of those agreements were negotiated, we did not have an independent board of directors or a management team independent of Occidental. As a result, the terms of those agreements,

including those that are discussed elsewhere, may be unfavorable and may not reflect terms that would have resulted from arm's-length negotiations between unaffiliated third parties. The terms relate to, among other things, the allocation of assets, liabilities, rights and other obligations between Occidental and us.

Risks Related to the Exchange Offer

If you do not exchange your original notes, you may have difficulty transferring them at a later time.

Original notes that are not exchanged will remain subject to restrictions on transfer and will not have rights to registration. If you do not participate in the exchange offer, your original notes will continue to be subject to the restrictions on transfer described in the offering memorandum distributed in connection with the private placement of the original notes. Accordingly, you would need to comply with the registration and prospectus delivery requirements of the Securities Act for any resale transaction. Each broker-dealer who holds original notes for its own account due to market-making or other trading activities and who receives exchange notes for its own account must acknowledge that it will deliver a prospectus in connection with any resale of the exchange notes. If any original notes are not tendered in the exchange or are tendered but not accepted, the trading market for such original notes could be negatively affected due to the limited amount of original notes expected to remain outstanding following the completion of the exchange offer.

If you wish to tender your original notes for related exchange notes, you must comply with the requirements described in this prospectus.

We will issue the exchange notes for the related original notes only if you properly tender the original notes before the Expiration Date in the manner set forth in this prospectus. Neither we nor the exchange agent has any duty to give you notice of defects or irregularities with respect to tenders of original notes for exchange.

If you are the beneficial owner of original notes that are held through a broker, dealer, commercial bank, trust company or other nominee, and you wish to tender such original notes in the exchange offer, you should promptly contact and instruct that person to tender on your behalf.

Risks Related to the Exchange Notes

We may not be able to repurchase the exchange notes upon a change of control trigger event or an offer to repurchase the exchange notes in connection with an asset sale as required by the indenture.

Under the terms of our indenture, upon the occurrence of specific types of change of control trigger events, we will be required to offer to repurchase all of the exchange notes at a price equal to 101% of the aggregate principal amount of the exchange notes repurchased, plus accrued and unpaid interest, up to but not including the date of repurchase. We may not have sufficient funds available to repurchase all of the exchange notes tendered pursuant to any such offer and any other indebtedness that would become payable upon a change of control.

Our Credit Facilities restrict, and any future credit agreements or other debt agreements to which we become a party may restrict, our ability to repurchase the exchange notes. If we are prohibited from repurchasing the exchange notes, we could seek the consent of our then-existing lenders to repurchase the exchange notes or we could attempt to refinance the borrowings that contain such prohibition. If we are unable to obtain a consent or refinance the debt, we could not repurchase the exchange notes. Our failure to repurchase tendered exchange notes could constitute a default under the indenture and might constitute a default under the terms of other indebtedness that we incur. The term "change of control," as defined in "Description of Exchange Notes—Certain Definitions," is limited to certain specified transactions and may not include other events that might adversely affect our financial condition. Our obligation to repurchase the exchange notes upon a change of control triggering event would not necessarily afford holders of exchange notes protection in the event of a highly leveraged transaction, reorganization, merger or similar transaction involving us.

Your ability to transfer the exchange notes may be limited by the absence of a trading market.

The exchange notes will be new securities for which currently there is no trading market. We do not initially intend to apply for listing of the exchange notes on any securities exchange or stock market. Although the initial purchasers have informed us that they currently intend to make a market in the exchange notes, they are not obligated to do so. In addition, they may discontinue any such market making at any time without notice. The liquidity of any market for the exchange notes will depend on the number of holders of those exchange notes, the interest of securities dealers in making a market in those exchange notes and other factors. Accordingly, we cannot assure you as to the development, maintenance or liquidity of any market for the exchange notes. If the exchange notes are traded after their initial issuance, they may trade at a discount to their initial offering price, depending on prevailing interest rates, the market for similar securities, our performance and other factors. Historically, the market for non-investment grade debt has been subject to disruptions that have caused substantial volatility in the prices of securities similar to the exchange notes. We cannot assure you that the market, if any, for the exchange notes will be free from similar disruptions. Any such disruption may adversely affect the holders of the exchange notes. To the extent that

an active trading market for the exchange notes does not develop, the liquidity and trading prices for the exchange notes may be harmed. Thus, you may not be able to liquidate your investment rapidly, and your lenders may not readily accept the exchange notes as collateral for loans.

Future trading prices of the exchange notes will depend on many factors, including but not limited to:

- our operating performance and financial condition;
- the interest of the securities dealers in making a market in the exchange notes; and
- the market for similar securities.

Changes in our credit ratings or the debt markets may adversely affect the market price of the exchange notes and our borrowing costs.

The price for the exchange notes will depend on a number of factors, including but not limited to:

- our credit ratings with major credit rating agencies;
- prevailing market interest rates and interest rates being paid by other companies similar to us;
- our financial condition, operating performance and future prospects;
- market analysts' perception of our company, our prospects and our industry in general; and
- the overall condition of the financial markets and global and domestic economies.

The condition of the financial markets and prevailing interest rates have fluctuated in the past and are likely to fluctuate in the future. Such fluctuations could have an adverse effect on the market price of the exchange notes. In addition, if rating agencies reduce the rating on the exchange notes or place the exchange notes on watch for a downgrade in the future, the market price of the notes may be adversely affected. If any rating of our outstanding debt is downgraded, raising capital will become more difficult, our borrowing costs may increase and the market price of the exchange notes may decrease. The credit rating agencies evaluate the industry in which we operate as a whole and may also change their credit rating for us based on their overall view of our industry.

The exchange notes will be effectively junior in right of payment to our secured debt and that of our guarantors.

The exchange notes and the guarantees are unsecured and therefore will be effectively junior in right of payment to any of our future secured debt and that of our subsidiary guarantors to the extent of the value of assets securing such debt. In the event of a bankruptcy or similar proceeding, the assets that serve as collateral for any secured debt will be available to satisfy the obligations under the secured debt before any payments are made on the exchange notes. Initially, the Credit Facilities are unsecured; however, initially we will be required to provide collateral for the Credit Facilities if our corporate family rating is Ba3 or lower from (or is unrated by) Moody's or our corporate credit rating is BB- or lower from (or is unrated by) S&P during the interim covenant period discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facilities". Outside the initial period, we will be required to provide collateral if our corporate family rating is B1 or lower from (or is unrated by) Moody's or our corporate credit rating is B+ or lower from (or is unrated by) S&P (unless our corporate family rating is B1 or our corporate credit rating is B+, and our other rating is BB or Ba2 or higher, as applicable).

The indenture under which the exchange notes were issued permits us to incur significant secured obligations without equally and ratably securing the exchange notes. Holders of any of our secured indebtedness or other obligations would have claims with respect to our assets constituting collateral for such indebtedness and obligations that are prior to your claims under the exchange notes. To the extent the value of the collateral is not sufficient to satisfy such indebtedness and obligations, the holders of that indebtedness and those obligations would be entitled to share with the holders of the exchange notes and the holders of other claims against us with respect to the remainder of our assets, if any. However, since we may be permitted to pledge all of our assets to secure our indebtedness and other obligations, there may be no assets remaining to satisfy the claims of holders of the exchange notes.

Claims of holders of the exchange notes will be structurally subordinated to claims of creditors of any of our existing and future non-guarantor subsidiaries.

Initially, certain immaterial subsidiaries will not guarantee the exchange notes. The non-guarantor subsidiaries represented less than 1% of our total assets and had no indebtedness as of December 31, 2014, and represented less than 1% of revenues for the twelve months ended December 31, 2014. In addition, in the future, certain subsidiaries may not be required to be, or may be delayed in becoming, a subsidiary guarantor. See “Description of Exchange Notes—Guarantees” and “Description of Exchange Notes—Certain Covenants—Future Guarantees.” In particular, any subsidiary that is a master limited partnership or a royalty trust will not be required to guarantee the exchange notes. Claims of holders of the exchange notes will be structurally subordinated to all of the liabilities of any subsidiaries that do not guarantee the exchange notes.

The guarantee of a subsidiary could be voided if it constitutes a fraudulent transfer under U.S. bankruptcy or similar state law, which would prevent the holders of the exchange notes from relying on that subsidiary to satisfy claims.

Under U.S. bankruptcy law and comparable provisions of state fraudulent transfer laws, to the extent the exchange notes would be guaranteed by a subsidiary, such subsidiary guarantees can be voided, or claims under the guarantee of a subsidiary may be further subordinated to all other debts of that subsidiary guarantor if, among other things, the subsidiary guarantor, at the time it incurred the indebtedness evidenced by its guarantee or, in some states, when payments become due under the guarantee, received less than reasonably equivalent value or fair consideration for the incurrence of the guarantee and at the time of incurrence:

- was insolvent or rendered insolvent by reason of such incurrence;
- was engaged in a business or transaction for which the guarantor’s remaining assets constituted unreasonably small capital; or
- intended to incur, or believed that it would incur, debts beyond its ability to pay those debts as they mature.

The guarantee of a subsidiary may also be voided, without regard to the above factors, if a court found that the subsidiary guarantor entered into the guarantee with the actual intent to hinder, delay or defraud its creditors.

A court would likely find that a subsidiary guarantor did not receive reasonably equivalent value or fair consideration for its guarantee if the subsidiary guarantor did not substantially benefit directly or indirectly from the issuance of the guarantees. Sufficient funds to repay the exchange notes may not be available from other sources, including the remaining subsidiary guarantors, if any. In addition, the court might direct you to repay any amounts that you already received from the subsidiary guarantor.

Each subsidiary guarantee will contain a provision intended to limit the subsidiary guarantor’s liability to the maximum amount that it could incur without causing the incurrence of obligations under its subsidiary guarantee to be a fraudulent transfer. Such provision may not be effective to protect the subsidiary guarantees from being voided under fraudulent transfer law.

THE EXCHANGE OFFER

This section of the prospectus describes the exchange offer. While we believe that the description covers the material terms of the exchange offer, this summary may not contain all of the information that is important to you. You should carefully read this entire document for a complete understanding of the exchange offer.

Purpose and Effects of the Exchange Offer

We sold the original notes in transactions that were exempt from or not subject to the registration requirements of the Securities Act. Accordingly, the original notes are subject to transfer restrictions. In general, you may not offer or sell the original notes unless either they are registered under the Securities Act or the offer or sale is exempt from or not subject to registration under the Securities Act and applicable state securities laws.

As a condition to the initial sale of the original notes, we and the initial purchasers entered into a registration rights agreement on October 1, 2014. We are offering the exchange notes under this prospectus in an exchange offer for the original notes to satisfy our obligations under the registration rights agreement. Under the registration rights agreement, we are required, among other things, to:

- within 365 days after the closing of the private placement on October 1, 2014, use our commercially reasonable efforts to cause to be effective a registration statement registering the proposed offer and exchange of any and all original notes for registered exchange notes with substantially identical terms, except that the exchange notes will not contain terms with respect to transfer restrictions or

additional interest for failure to effect an exchange offer;

- keep the exchange offer open for not less than 20 business days after the date notice thereof is mailed to holders of the original notes; and
- use our commercially reasonable efforts to consummate the exchange offer within 30 business days after the registration statement has become effective, or such longer period as may be required by United States securities laws.

In addition, under certain circumstances, we may be required to file a shelf registration statement to cover resales of original notes and exchange notes.

If we fail to comply with the requirements of the registration rights agreement, the interest rate on the original notes may increase. Specifically, if (i) the exchange offer is not consummated within 30 business days after the 365th day following the closing of the private placement on October 1, 2014 (or, if the exchange offer is not permitted, the shelf registration statement is not filed on or prior to the date specified for such filing) or (ii) a registration statement with respect to the original notes is filed and declared effective but thereafter ceases to be effective or fails to be usable for its intended purpose (any such event referred to in the clauses above, a “Registration Default”), the annual interest rate borne by the original notes will be increased by 0.25% per annum with respect to the first 90 days after the applicable Registration Default, and, if such default is not cured prior to the end of such 90-day period, by an additional 0.25% per annum (together with the increase described in the preceding clause, as applicable, the “Additional Interest”) with respect to each subsequent 90-day period, up to a maximum amount of additional interest of 0.5% per annum.

The summary in this document of the registration rights agreement is not complete and is subject to, and is qualified in its entirety by, all the provisions of the registration rights agreement. We urge you to read the entire registration rights agreement carefully. A copy of the registration rights agreement has been incorporated by reference in the registration statement of which this prospectus forms a part. The registration statement is intended to satisfy some of our obligations under the registration rights agreement.

The exchange offer will be open for at least 20 business days (or longer, if required by applicable law) after the date notice thereof is mailed to the holders of the original notes. During the exchange offer period, we will deliver exchange notes for all original notes properly tendered and not withdrawn before the Expiration Date. The exchange notes will be registered and the transfer restrictions, registration rights and provisions for additional interest relating to the original notes will not apply to the exchange notes. The exchange notes issued in exchange for the original notes are expected to bear a different CUSIP number and ISIN number from any unexchanged original notes. Holders of the exchange notes and the original notes will vote as one series under the indenture governing the notes.

We have not requested, and do not intend to request, an interpretation by the staff of the SEC with respect to whether the exchange notes may be offered for sale, resold or otherwise transferred by any holder without compliance with the registration and prospectus delivery provisions of the Securities Act. Based on interpretations by the staff of the SEC set forth in no-action letters issued to third parties, including Exxon Capital Holdings Corp. (available May 13, 1988), Morgan Stanley & Co. Incorporated (available June 5, 1991) and Shearman & Sterling (available July 2, 1993), we believe the exchange notes may be offered for resale, resold and otherwise transferred by any holder without compliance with the registration and prospectus delivery provisions of the Securities Act, provided such holder meets the following conditions:

- such holder is not a broker-dealer who purchased original notes directly from us for resale pursuant to Rule 144A or any other available exemption under the Securities Act;
- such holder is not our “affiliate”; and
- such holder acquires exchange notes in the ordinary course of its business and has no arrangement or understanding with any person to participate in the distribution of the exchange notes.

If you do not satisfy all of the above conditions, you cannot participate in the exchange offer. Rather, in the absence of an exemption, you must comply with the registration and prospectus delivery requirements of the Securities Act in connection with a resale of the original notes. Any holder required to comply with such registration and prospectus delivery requirements may incur liabilities under the Securities Act for which the holder will not be entitled to indemnification from us.

A broker-dealer that has bought original notes for its own account as part of its market-making or other trading activities must deliver a prospectus in order to resell the exchange notes it receives pursuant to the exchange offer. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer for such purpose, and we have agreed in the registration rights agreement to make this prospectus available to such broker-dealers upon reasonable request for the period required by the Securities Act. See “Plan of Distribution.” Each broker-dealer that receives exchange notes in the exchange offer must acknowledge that it will deliver a prospectus meeting the requirements of the Securities Act in connection with any resale of exchange notes. The accompanying letter of transmittal states that by so acknowledging and by

delivering a prospectus, a broker-dealer will not be deemed to admit that it is an “underwriter” within the meaning of the Securities Act.

We are not making the exchange offer to, nor will we accept tenders for exchange from, holders of original notes in any jurisdiction in which this exchange offer or its acceptance would not comply with applicable state securities laws or applicable laws of a foreign jurisdiction.

Participation in the exchange offer is voluntary and you should carefully consider whether to participate. We urge you to consult your financial and tax advisors in making your decision on whether to participate in the exchange offer.

Consequences of Failure to Exchange

Original notes that are not exchanged for exchange notes in the exchange offer will remain “restricted securities” within the meaning of Rule 144(a)(3) under the Securities Act, and will therefore continue to be subject to restrictions on transfer. Original notes will remain outstanding and will continue to accrue interest, but holders of such original notes will not be able to require us to register them under the Securities Act. Accordingly, following completion of the exchange offer any original notes that remain outstanding may not be offered, sold, pledged or otherwise transferred except:

- (1) to us, upon redemption thereof or otherwise;
- (2) so long as the original notes are eligible for resale pursuant to Rule 144A, to a person whom the seller reasonably believes is a qualified institutional buyer within the meaning of Rule 144A, purchasing for its own account or for the account of a qualified institutional buyer to whom notice is given that the resale, pledge or other transfer is being made in reliance on Rule 144A;
- (3) in an offshore transaction in accordance with Regulation S under the Securities Act;
- (4) pursuant to an exemption from registration in accordance with Rule 144, if available, under the Securities Act;
- (5) in reliance on another exemption from the registration requirements of the Securities Act; or
- (6) pursuant to an effective registration statement under the Securities Act.

In all of the situations discussed above, the resale must be in compliance with the Securities Act, any applicable securities laws of any state of the United States and any applicable securities laws of any foreign country. Any resale of original notes will also be subject to certain requirements of the registrar or any co-registrar being met, including receipt by the registrar or co-registrar of a certification and, in the case of (3), (4) and (5) above, an opinion of counsel reasonably acceptable to us and the registrar and any co-registrar.

To the extent original notes are tendered and accepted in the exchange offer, the principal amount of outstanding original notes will decrease with a resulting decrease in the liquidity in the market therefor. Accordingly, the liquidity of the market of the original notes could be adversely affected following completion of the exchange offer. See “Risk Factors—Risks Related to the Exchange Offer.”

Terms of the Exchange Offer

Upon the terms and subject to the conditions set forth in this prospectus and in the accompanying letter of transmittal, we will accept any and all original notes validly tendered (and not withdrawn) prior to 5:00 p.m., New York City time, on the Expiration Date. We will issue the relevant series of exchange notes in principal amount equal to the principal amount of the relevant series of original notes surrendered in the exchange offer. The exchange notes will accrue interest on the same terms as the relevant series of original notes; however, holders of the original notes accepted for exchange will not receive accrued interest thereon at the time of exchange; rather, all accrued interest on the original notes will become obligations under the exchange notes. Holders may tender some or all of their original notes pursuant to the exchange offer. However, original notes may be tendered only in denominations of \$2,000 and integral multiples of \$1,000 principal amount in excess thereof.

The form and terms of the exchange notes are the same as the form and terms of the relevant series of original notes, except that:

- the exchange notes will have been registered under the Securities Act, and the exchange notes will not bear legends restricting their transfer pursuant to the Securities Act; and
- except as otherwise described above, holders of the exchange notes will not be entitled to any rights under the registration rights agreement.

As of the date of this prospectus, \$5.0 billion in aggregate principal amount of the original notes are outstanding. The exchange notes will evidence the same debt as the relevant series of original notes that they replace, and will be issued under, and be entitled to the benefits of, the indenture which governs the original notes, including the payment of principal and interest.

The term “holder,” as used in this prospectus, means those DTC participants in whose name interests in the global notes are credited on the books of DTC, and those persons who hold interests through such DTC participants. The term “original notes,” as used in this prospectus, means such interests in the global notes.

Holders of the original notes do not have any appraisal or dissenter’s rights under state law or the indenture governing the notes in connection with the exchange offer. We intend to conduct the exchange offer in accordance with the requirements of the registration rights agreement, Securities Act, the Exchange Act, and the SEC’s rules and regulations thereunder.

The exchange agent will act as agent for the tendering holders of the original notes for the purposes of receiving the exchange notes. The exchange notes delivered in the exchange offer will be issued promptly following the Expiration Date. We will return any original notes that we do not accept for exchange for any reason without expense to their tendering holders promptly after the expiration or termination of the exchange offer.

If any tendered original notes are not accepted for exchange because they do not comply with the procedures set forth in this prospectus and the accompanying letter of transmittal, our withdrawal of the exchange offer, the occurrence of certain other events set forth herein or otherwise, such unaccepted original notes will be returned, without expense, to the tendering holder promptly after the Expiration Date or our withdrawal of the exchange offer. Such non-exchanged original notes will be credited to an account maintained by DTC. Any acceptance, waiver of default or a rejection of a tender of original notes shall be at our discretion and shall be conclusive, final and binding.

Holders who tender original notes in the exchange offer will not be required to pay brokerage commissions or fees or, subject to the instructions in the letter of transmittal, transfer taxes with respect to the exchange of the original notes in the exchange offer. We will pay all charges and expenses, other than certain taxes, in connection with the exchange offer. See “—Fees and Expenses.”

Expiration Date; Extensions; Amendments

The term “Expiration Date” with respect to the exchange offer means 5:00 p.m., New York City time, on April 28, 2015 unless we, in our sole discretion, extend the exchange offer, in which case the term “Expiration Date” shall mean the latest date and time to which the exchange offer is extended.

If we extend the exchange offer, we will notify the exchange agent and each registered holder of original notes of any extension by oral or written notice and will make a public announcement thereof, each prior to 9:00 a.m., New York City time, no later than on the next business day after the previously scheduled Expiration Date. Any notice relating to the extension of the exchange offer will disclose the number of securities tendered as of the date of the notice, as required by Rule 14e-1(d) under the Exchange Act.

We reserve the right, in our sole discretion,

- to extend the exchange offer;
- to delay accepting any original notes;
- if any of the conditions set forth below under “—Conditions to the Exchange Offer” have not been satisfied, to terminate the exchange offer or waive any conditions that have not been satisfied; or
- subject to the terms of the registration rights agreement, to amend the terms of the exchange offer in any manner.

We may effect any such extension, waiver, termination or amendment by giving written notice thereof to the exchange agent and each registered holder of original notes.

Except as specified in the second paragraph under this heading, we will make a public announcement of any such extension, termination, amendment or waiver as promptly as practicable. If we amend or waive any condition of the exchange offer in a manner determined by us to constitute a material change to the exchange offer, we will promptly disclose such amendment or waiver in a prospectus supplement that will be distributed to the holders of the original notes. The exchange offer will then be extended for a period of five to ten business days, as required by law, depending upon the significance of the amendment or waiver and the manner of disclosure to the registered holders.

We will have no obligation to publish, advertise, or otherwise communicate any public announcement of any delay, extension, amendment or termination that we may choose to make, other than by making a timely release to an appropriate news agency.

Interest on the Exchange Notes

The exchange notes will accrue interest on the same terms as the relevant series of original notes: the 2020 exchange notes will bear interest at a rate of 5% per annum, the 2021 exchange notes will bear interest at a rate of 5 1/2% per annum and the 2024 exchange notes will bear interest at a rate of 6% per annum. Interest on the 2020 exchange notes will be paid semi-annually in arrears on January 15 and July 15 of each year, beginning on July 15, 2015. Interest on the 2021 exchange notes will be paid semi-annually in arrears on March 15 and September 15 of each year, beginning on March 15, 2015. Interest on the 2024 exchange notes will be paid semi-annually in arrears on May 15 and November 15 of each year, beginning on May 15, 2015.

Procedures for Tendering Original Notes

To participate in the exchange offer, you must properly tender your original notes to the exchange agent as described below.

Tenders of Original Notes; Book-Entry Delivery Procedure

All of the original notes are held in book-entry form and are currently represented by global notes registered in the name of Cede & Co., the nominee of DTC. We have confirmed with DTC that the original notes may be tendered using the Automated Tender Offer Program (“ATOP”) procedures.

The exchange agent will establish an account with respect to the original notes at DTC for purposes of the exchange offer within two business days after the date of this prospectus, and any financial institution that is a participant in DTC that wishes

to participate in the exchange offer may make book-entry delivery of the original notes by causing DTC to transfer such original notes into the exchange agent’s account in accordance with DTC’s procedures for such transfer. The confirmation of a book-entry transfer into the exchange agent’s account at DTC is referred to as a “Book-Entry Confirmation.” In addition, DTC participants on or before the Expiration Date must transmit their acceptance using ATOP procedures, for which the exchange offer is eligible, and DTC will then edit and verify the acceptance and send an Agent’s Message to the exchange agent for its acceptance.

An “Agent’s Message” is a message transmitted by DTC to, and received by, the exchange agent and forming a part of the Book-Entry Confirmation, which states that DTC has received instructions from the participant to tender the original notes and that such participant expressly acknowledged and agreed to be bound by the terms of the letter of transmittal and the representations in the letter of transmittal, and that we may enforce such agreement against such participant.

In order to validly tender the original notes in the exchange offer, the exchange agent must receive, on or prior to the Expiration Date, an Agent’s Message under the ATOP procedures that confirms that:

- DTC has received your instructions to tender your original notes; and
- You agree to be bound by the terms of the letter of transmittal.

The tender by a holder of original notes pursuant to the procedures set forth above will constitute the tendering holder’s acceptance of all of the terms and conditions of the exchange offer. Our acceptance for exchange of original notes tendered pursuant to the procedures described above will constitute a binding agreement between such tendering holder and us in accordance with the terms and subject to the conditions of the exchange offer. Only holders are authorized to tender their original notes.

The tender by a holder of original notes pursuant to the procedures set forth above will constitute the tendering holder’s acceptance of all of the terms and conditions of the exchange offer. Our acceptance for exchange of original notes tendered pursuant to the procedures described above will constitute a binding agreement between such tendering holder and us in accordance with the terms and subject to the conditions of the exchange offer. Only holders are authorized to tender their original notes.

By agreeing to be bound by the letter of transmittal, you will represent to us that, among other things:

- any exchange notes that you receive will be acquired in the ordinary course of business;
- you are not engaged in and do not intend to engage in the distribution of the exchange notes;
- you have no arrangement or understanding with any person or entity to participate in the distribution of the exchange notes;
- you are not an “affiliate,” as defined in Rule 405 under the Securities Act, of us or our subsidiary guarantors or, if you are an affiliate, that you will comply with the registration and prospectus delivery requirements of the Securities Act to the extent applicable; and
- if you are a broker-dealer that will receive exchange notes for your own account in exchange for the original notes, you acquired those

original notes as a result of market-making activities or other trading activities and you will deliver this prospectus, as required by law, in connection with any resale of the exchange notes.

The delivery of original notes through DTC and any Agent's Message transmitted through ATOP is at the election and risk of the persons tendering original notes. Delivery of documents to DTC does not constitute delivery to the exchange agent. You must allow sufficient time for completion of the ATOP procedures during normal business hours of DTC on or prior to the Expiration Date. Tender and delivery will be deemed made only when actually received by the exchange agent. Holders should be aware that DTC may have deadlines earlier than the Expiration Date for the exchange offer. Accordingly, holders of original notes wishing to participate in the exchange offer are urged to contact DTC as soon as possible.

Except as provided below, unless tender of the original notes is made in accordance with ATOP procedures on or prior to the Expiration Date, we may, at our option, reject the tender of such original notes as invalid and ineffective. The exchange of original notes for exchange notes will be made only against the tendered original notes and for the relevant series of the tendered original notes, which must be deposited with the exchange agent prior to or on the Expiration Date.

Tender of Original Notes Held Through a Nominee

If you beneficially own original notes through a bank, depository, broker, trust company or other nominee and wish to tender your original notes, you must instruct such holder to cause your original notes to be tendered on your behalf. Such nominee cannot tender original notes on behalf of a holder of original notes without such holder's instructions. Holders whose original notes are held by a bank, depository, broker, trust company or other nominee should be aware that such nominee may have deadlines earlier than the Expiration Date. Accordingly, such holders are urged to contact any such nominee through which they hold their original notes as soon as possible in order to learn of its applicable deadlines.

Delivery of Original Notes Held in Physical Form

We do not believe any original notes exist in physical form. If you believe you hold original notes in physical form, please contact the exchange agent regarding procedures for participating in the exchange offer. Any original notes in physical form must be tendered using a physical letter of transmittal and such original notes must be delivered to the Exchange Agent at its address set forth below under the heading "—Exchange Agent."

Determination of Validity

All questions as to the validity, form, eligibility (including time of receipt), acceptance and withdrawal of tendered original notes will be determined by us, which determination will be conclusive, final and binding. Alternative, conditional or contingent tenders of original notes may not be considered valid and may be rejected by us. We reserve the absolute right to reject any and all original notes not properly tendered or any original notes our acceptance of which, in the opinion of our counsel, would be unlawful.

We also reserve the right to waive any defects, irregularities or conditions of tender as to particular original notes. The interpretation of the terms of our exchange offer (including the instructions in the letter of transmittal) by us will be conclusive, final and binding on all parties. Unless waived, any defects or irregularities in connection with tenders of original notes must be cured within such time as we shall determine.

Although we intend to notify holders of defects or irregularities with respect to tenders of original notes through the exchange agent, neither we, the exchange agent nor any other person is under any duty to give such notice, nor shall they incur any liability for failure to give such notification. Tenders of original notes will not be deemed to have been made until such defects or irregularities have been cured or waived.

Any original notes tendered into the exchange agent's account at DTC that are not validly tendered and as to which the defects or irregularities have not been cured or waived within the timeframes established by us in our sole discretion, if any, will be credited back to the account maintained by the applicable DTC participant with such book-entry transfer facility.

Withdrawal of Tenders

Tenders of original notes in the exchange offer may be withdrawn at any time on or prior to the Expiration Date by sending a notice of withdrawal to the exchange agent using the ATOP procedures. To be effective, any notice of withdrawal must specify the name and number of the account at DTC to be credited with such withdrawn original notes and must otherwise comply with the ATOP procedures.

All questions as to the validity, form and eligibility (including time of receipt) of such notices will be determined by us, which determination shall be conclusive, final and binding on all parties. No withdrawal of original notes will be deemed to have been properly made until all defects or

irregularities have been cured or expressly waived. Neither we, the exchange agent nor any other person will be under any duty to give notification of any defects or irregularities in any notice of withdrawal or revocation, nor shall we or they incur any liability for failure to give any such notification. Any original notes so withdrawn will be deemed not to have been validly tendered for purposes of the exchange offer and no exchange notes will be issued with respect thereto unless the original notes so withdrawn are retendered on or prior to the Expiration Date. Properly withdrawn original notes may be retendered by following the procedures described above under “—Procedures for Tendering Original Notes” at any time on or prior to the Expiration Date.

Any original notes which have been tendered but which are not accepted for exchange due to the rejection of the tender due to uncured defects or the prior termination of the exchange offer, or which have been validly withdrawn, will be returned to the holder thereof unless otherwise provided in the letter of transmittal, promptly following the Expiration Date or, if so requested in the notice of withdrawal, promptly after receipt by us of notice of withdrawal without cost to such holder.

Issuance of Exchange Notes

We will be deemed to have accepted validly tendered original notes when, as and if we have given written notice thereof to the exchange agent, which is Wells Fargo Bank, National Association. In all cases, we will issue the relevant series of exchange notes for the series of original notes that we have accepted for exchange under the exchange offer only after the exchange agent receives (i) a Book-Entry Confirmation of such original notes into the exchange agent’s account at DTC; and (ii) a properly transmitted Agent’s Message. Such exchange notes will be issued promptly following the expiration or termination of the exchange offer.

Return of Original Notes

If any tendered original notes are not accepted for any reason described herein or if original notes are withdrawn or are submitted for a greater principal amount than you desire to exchange, those original notes will be returned, at our cost, to the exchange agent’s account at DTC. Any such original notes will be credited to an account maintained with DTC. These actions will occur promptly after the expiration or termination of the exchange offer.

Conditions to the Exchange Offer

The exchange offer will not be subject to any conditions, other than:

- that the exchange offer does not violate applicable law or any applicable interpretations of the staff of the SEC;
- that no action or proceeding shall have been instituted or threatened in any court or by any governmental agency with respect to the exchange offer; and
- the due tendering of original notes and the delivery to the exchange agent of the letter of transmittal or an Agent’s.

If we determine that any of the conditions to the exchange offer are not satisfied in accordance with their terms, we may:

- refuse to accept any original notes and return all tendered original notes to the tendering holders;
- terminate the exchange offer;
- extend the exchange offer and retain all original notes tendered prior to the Expiration Date, subject, however, to the rights of holders to withdraw such original notes; or
- waive such unsatisfied conditions with respect to the exchange offer and accept all validly tendered original notes which have not been withdrawn.

If our waiver of an unsatisfied condition constitutes a material change to the exchange offer, we will promptly disclose such waiver by means of a prospectus supplement that will be distributed to the holders of the original notes, and will extend the exchange offer for a period of five to ten business days, depending upon the significance of the waiver and the manner of disclosure to the registered holders, if the exchange offer would otherwise expire during such five to ten business day period.

The conditions listed above are for our sole benefit and we may assert these rights regardless of the circumstances giving rise to any of these conditions. We may waive these conditions in our reasonable discretion in whole or in part at any time and from time to time. If we fail at any time to exercise any of the above rights, the failure will not be deemed a waiver of these rights, and these rights will be deemed ongoing rights which may be asserted at any time and from time to time.

In addition, we will not accept for exchange any original notes tendered, and no exchange notes will be issued in exchange for those original notes, if at such time the registration statement of which this prospectus forms a part has not been declared effective by the SEC, or if at such time any stop order shall be threatened or in effect with respect to the registration statement of which this prospectus constitutes a part or the qualification of the indenture under the Trust Indenture Act of 1939, as amended. In any of those events we are required to use commercially reasonable efforts to have the registration statement of which this prospectus forms a part be declared effective by the SEC and obtain the withdrawal of any stop order at the earliest possible moment, as applicable.

Termination of Certain Rights

All registration rights under the registration rights agreement benefiting the holders of the original notes will terminate when we consummate the exchange offer. That includes all rights to receive additional interest in the event of a registration default under the registration rights agreement.

Exchange Agent

Wells Fargo Bank, National Association has been appointed as exchange agent for the exchange offer. The exchange agent, among other things, will not be (i) liable for any act or omission unless such act or omission constitutes its own gross negligence or willful misconduct and in no event will the exchange agent be liable to a security holder, us or any third party for special, punitive, indirect or consequential damages, including, but not limited to, lost profits, arising in connection with the exchange offer or its duties and responsibilities related to the exchange offer, (ii) obligated to take any legal action with respect to the exchange offer which might, in its judgment, involve any risk of expense, loss or liability, unless it will be furnished with indemnity satisfactory to it or (iii) liable or responsible for any statement contained in this prospectus. We will indemnify the exchange agent with respect to certain matters relating to the exchange offer.

You should direct questions and requests for assistance, requests for additional copies of this prospectus, the letter of transmittal or requests for other documents to the exchange agent as follows:

Delivery by Registered or Certified Mail:

Wells Fargo Bank, N.A.
Corporate Trust Operations
P.O. Box 1517
Minneapolis, MN 554802-1517

Regular Mail or Overnight Courier:

Wells Fargo Bank, N.A.
Corporate Trust Operations
N9303-121
6th & Marquette Avenue
Minneapolis, MN 554802-1517

In Person by Hand Only:

Wells Fargo Bank, N.A.
Northstar East Building
608 2nd Avenue South, 12th Floor Avenue
Minneapolis, MN 554802-1517

For Information or Confirmation by Telephone:

(800) 344-5128

Wells Fargo Bank, National Association also serves as trustee under the indenture governing the notes.

Fees and Expenses

We will bear the expenses of soliciting tenders with respect to the exchange offer. The principal solicitation is being made by mail by the exchange agent; however, additional solicitation may be made by email, telephone or in person by our or our affiliates' officers and regular employees.

We have not retained any dealer-manager in connection with the exchange offer and no payments will be made to brokers, dealers or others soliciting acceptance of the exchange offer. However, reasonable and customary fees will be paid to the exchange agent for its services and it will be reimbursed for its reasonable out-of-pocket expenses. We will also pay other cash expenses to be incurred in connection with the exchange offer, including SEC registration fees, our accounting and legal fees, printing costs and related fees and expenses.

Our out-of-pocket expenses for the exchange offer will include fees and expenses of the exchange agent and the trustee under the indenture governing the notes, accounting and legal fees and printing costs, among others.

Transfer Taxes

We will pay all transfer taxes, if any, applicable to the exchange of the original notes pursuant to the exchange offer. If, however, exchange notes or original notes for principal amounts not tendered or accepted for exchange are to be delivered to, or are to be registered or issued in the name of, any person other than the registered holder of the original notes, or if a transfer tax is imposed for any reason other than the exchange of the original notes pursuant to the exchange offer, then the amount of any such transfer taxes (whether imposed on the tendering holder or any other persons) will be payable by the tendering holder. If satisfactory evidence of payment of such taxes or exemption therefrom is not submitted to the exchange agent, the amount of such transfer taxes will be billed directly to such tendering holder.

Accounting Treatment for the Exchange Offer

The exchange notes will be recorded at the carrying value of the original notes and no gain or loss for accounting purposes will be recognized.

Other

You do not have to participate in the exchange offer. You should carefully consider whether to accept the terms and conditions of this exchange offer. We urge you to consult your financial and tax advisors in deciding what action to take with respect to the exchange offer.

USE OF PROCEEDS

The exchange offer is intended to satisfy our obligations under the registration rights agreement. We will not receive any proceeds from the issuance of the exchange notes. In exchange for issuing the exchange notes as contemplated in this exchange offer, we will receive original notes in the same principal amount. The form and terms of the exchange notes are identical in all material respects to the form and terms of the original notes, except as described below under the heading “The Exchange Offer—Terms of the Exchange Offer.” The original notes tendered in exchange for the exchange notes will be retired and canceled and cannot be re-issued. Accordingly, issuance of the exchange notes will not result in any increase in our outstanding debt.

CAPITALIZATION

The following table sets forth our historical capitalization as of December 31, 2014. The table below should be read in conjunction with "Selected Financial Data," —"Management's Discussion and Analysis of Financial Condition and Results of Operations" and our audited consolidated and combined financial statements and the notes to those statements included elsewhere in this prospectus.

**December 31,
2014**

(in millions)

Debt Outstanding

Long-term debt:

Revolving Credit Facility	\$	360
Term Loan Facility		1,000
5.00% notes due 2020		1,000
5.50% notes due 2021		1,750
6.00% notes due 2024		2,250
Total debt		6,360

Equity

Common stock (2.0 billion shared authorized at \$0.01 par value)		
Par value		4
Additional paid-in capital		4,748
Accumulated deficit		(2,117)
Accumulated other comprehensive income (loss)		(24)
Total Capitalization	\$	8,971

SELECTED FINANCIAL DATA

Prior to the Spin-off on November 30, 2014, the following selected financial data was derived from the California business of Occidental. All financial information presented after the Spin-off represents CRC's consolidated results of operations, financial position and cash flows. Accordingly:

- The selected statement of operations and cash flows data for the year ended December 31, 2014 consists of the stand-alone consolidated results of California Resources Corporation post Spin-off and the consolidated and combined results of the California business prior to the Spin-off. The selected statement of operations data for the years ended December 31, 2013, 2012, 2011, and 2010 consist entirely of the combined results of the California business.
- The selected balance sheet data at December 31, 2014 consists of the consolidated balances of California Resources Corporation, while the selected balance sheet data at December 31, 2013, 2012, 2011 and 2010 consists of the combined balances of the California business.

	Year Ended December 31,				
	2014	2013	2012	2011	2010
Statement of Operations Data	(in millions)				

Revenues	\$	4,173	\$	4,284	\$	4,073	\$	3,934	\$	2,912
Income / (loss) before income taxes	\$	(2,421)	\$	1,447	\$	1,181	\$	1,641	\$	1,129
Net income / (loss)	\$	(1,434)	\$	869	\$	699	\$	971	\$	719
Per common share ^(a)										
Basic	\$	(3.75)	\$	2.24	\$	1.80	\$	2.50	\$	1.85
Diluted	\$	(3.75)	\$	2.24	\$	1.80	\$	2.50	\$	1.85

Statement of Cash Flows Data

Net cash provided by operating activities	\$	2,371	\$	2,476	\$	2,223	\$	2,456	\$	1,751
Capital investments	\$	(2,020)	\$	(1,669)	\$	(2,331)	\$	(2,164)	\$	(1,056)
Acquisitions	\$	(288)	\$	(48)	\$	(427)	\$	(1,405)	\$	(448)
Borrowings, net of costs	\$	6,290	\$	—	\$	—	\$	—	\$	—
Spin-off related dividends to Occidental	\$	(6,000)	\$	—	\$	—	\$	—	\$	—
(Distributions to) contributions from Occidental, net	\$	(335)	\$	(763)	\$	532	\$	1,106	\$	(248)

(a) See Note 13 - Earnings Per Share, in the Notes to the Financial Statements

	As of December 31,									
	2014	2013	2012	2011	2010					
	(in millions)									
Balance Sheet Data										
Total current assets	\$	701	\$	254	\$	245	\$	195	\$	148
Property, plant and equipment, net	\$	11,685	\$	14,008	\$	13,499	\$	11,778	\$	8,823
Total assets	\$	12,497	\$	14,297	\$	13,764	\$	11,989	\$	8,987
Total current liabilities	\$	906	\$	689	\$	551	\$	664	\$	471
Long-term debt	\$	6,360	\$	—	\$	—	\$	—	\$	—
Equity / Net Investment	\$	2,611	\$	9,989	\$	9,860	\$	8,624	\$	6,557

The selected financial data presented above should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated and combined financial statements and accompanying notes included elsewhere in this prospectus.

MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of financial condition and results of operations (MD&A) should be read in conjunction with the information under the headings “Risk Factors,” “Selected Financial Data,” and “Business,” as well as the audited consolidated and combined financial statements and the related notes thereto, all appearing elsewhere in this prospectus.

Except when the context otherwise requires or where otherwise indicated, (1) all references to “CRC,” the “Company,” “we,” “us” and “our” refer to California Resources Corporation and its subsidiaries, or the California business, (2) all references to the “California business” refer to Occidental’s California oil and gas exploration and production operations and related assets, liabilities and obligations, which we assumed in connection with the spin-off from Occidental on November 30, 2014 (the “Spin-off”) and (3) all references to “Occidental” refer to Occidental Petroleum Corporation, our former parent, and its subsidiaries.

This MD&A contains forward-looking statements concerning trends or events potentially affecting our business or future performance, including, without limitation, statements relating to our plans, strategies, objectives, expectations and intentions. The words “aim,” “anticipate,”

“believe,” “budget,” “continue,” “could,” “effort,” “estimate,” “expect,” “forecast,” “goal,” “guidance,” “intend,” “likely,” “may,” “might,” “objective,” “outlook,” “plan,” “potential,” “predict,” “project,” “seek,” “should,” “target,” “will” or “would” and similar expressions identify forward-looking statements. We do not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements contained in this prospectus. See “Cautionary Note Regarding Forward-Looking Statements” and “Risk Factors.”

The Separation and Spin-off

We are an independent oil and natural gas exploration and production company operating properties exclusively within the State of California. We were incorporated in Delaware as a wholly-owned subsidiary of Occidental on April 23, 2014 and remained a wholly-owned subsidiary of Occidental until the Spin-off. On November 30, 2014, Occidental distributed shares of our common stock on a pro rata basis to Occidental stockholders and we became an independent, publicly traded company. Occidental retained approximately 18.5% of our outstanding shares of common stock which it has stated it intends to divest within 18 months of the Spin-off. Occidental has also granted us a proxy to vote the shares of our common stock that Occidental retained immediately after the distribution in proportion to the votes cast by our stockholders.

Basis of Presentation and Certain Factors Affecting Comparability

Up until the Spin-off, the accompanying consolidated and combined financial statements were derived from the consolidated financial statements and accounting records of Occidental. These consolidated and combined financial statements reflect the historical results of operations, financial position and cash flows of the California business. All financial information presented after the Spin-off consists of the stand-alone consolidated results of operations, financial position and cash flows of CRC. We account for our share of oil and gas exploration and production ventures in which we have a direct working interest, by reporting our proportionate share of assets, liabilities, revenues, costs and cash flows within the relevant lines on the balance sheets and statements of income and cash flows.

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

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

Had we been a stand-alone company for the full year 2014, and had the same level of debt throughout the year as we did on December 31, 2014, of approximately \$6.4 billion, we would have incurred \$314 million, \$186 million after-tax, of interest expense, on a pro-forma basis, for the year ended December 31, 2014, compared to the \$72 million pre-tax interest expense reported in our statement of operations for the year then ended.

Business Environment and Industry Outlook

Our operating results and those of the oil and gas industry as a whole are heavily influenced by commodity prices. Oil and gas index prices and differentials may fluctuate significantly, generally as a result of changes in supply and demand and other market-related uncertainties. These and other factors make it impossible to predict realized prices reliably. We respond to economic conditions primarily by adjusting our capital investments to be in line with current economic conditions, including adjusting the size and allocation of our capital program. The changes in the capital program have an impact on our production levels and cash flows.

Given the recent volatile and deteriorating oil price environment, as well as our leverage, we began a hedging program shortly after the Spin-off to protect against our down-side price risk and preserve our ability to execute our capital program. In December 2014, we purchased put options with a \$50 per barrel Brent strike price, measured monthly. This initial program covers almost all of our oil production for the first six months of 2015. More recently, we put into place additional hedging instruments to protect the pricing for almost two-thirds of our expected third quarter 2015 oil production. For this program we chose a combination of Brent-based collars (between \$55 and \$72) for 30,000 barrels per day for July through September as well as put options at \$50 per barrel Brent for 40,000 barrels per day in the same period. In addition, we sold a \$75 per

barrel call for 30,000 barrels per day of oil production in March through June of 2015. Going forward as an independent company, we will continue to be strategic and opportunistic in implementing any hedging program. Our objective is to protect against the cyclical nature of commodity prices to provide a level of certainty around our margins and cash flows necessary to implement our investment program.

We sell all of our crude oil into California markets, which typically reflect international waterborne-based prices because the structural energy deficit in the state results in most of its oil being imported. Over the last several years, these prices have exceeded and continue to exceed West Texas Intermediate (“WTI”) based prices for comparable grades. Due to much lower levels of natural gas production compared to our oil production, the changes in natural gas prices have a significantly lower impact on our operating results. Lower natural gas prices generally have a positive effect on our steamflood projects that use natural gas to generate the steam being injected. Average oil prices were lower in 2014 than 2013, caused by a steep decline in prices in the last half of 2014. Average Brent prices were \$108.76 per barrel in 2013 and \$99.51 per barrel in 2014 ending 2014 at \$57.33. Our realized price for crude oil as a percentage of Brent prices was approximately 93% and 96% for 2014 and 2013, respectively. Oil prices continued to decline in the early part of 2015.

The following table presents the average daily WTI oil, Brent oil and NYMEX gas prices for each of the years ended December 31, 2014, 2013 and 2012:

	2014	2013	2012
WTI oil (\$/Bbl)	\$ 93.00	\$ 97.97	\$ 94.21
Brent oil (\$/Bbl)	\$ 99.51	\$ 108.76	\$ 111.70
NYMEX gas (\$/Mcf)	\$ 4.34	\$ 3.66	\$ 2.81

Oil prices and differentials will continue to be affected by (i) global supply and demand, which are generally a function of global economic conditions, the actions of OPEC, other significant producers and governments, inventory levels, threatened or actual production or refining disruptions, the effects of conservation, technological advances and regional market conditions; (ii) transportation capacity and cost in producing areas; (iii) currency exchange rates; and (iv) the effect of changes in these variables on market perceptions.

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

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

Our earnings are also affected by the performance of our processing and power generation assets. We process our wet gas to extract NGLs and other natural gas byproducts, and 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. In addition, a portion of the power produced by our Elk Hills power plant is used for certain of our operations while a majority of the output is sold to third parties.

Seasonality

Seasonality is not a primary driver of changes in our quarterly earnings during the year.

Taxes

Deferred tax liabilities, net of deferred tax assets of \$444 million, were approximately \$2.0 billion at December 31, 2014. The current portion of total deferred tax assets was \$61 million as of December 31, 2014, which was reported in other current assets. The realization of deferred tax assets is assessed periodically based on several factors, including our expectation to generate sufficient future taxable income and reversal of taxable temporary differences.

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

	2014	2013	2012
Pre-tax income/(loss)	\$ (2,421)	\$ 1,447	\$ 1,181

Income tax (expense)/benefit	987	(578)	(482)
Net income/(loss)	<u>\$ (1,434)</u>	<u>\$ 869</u>	<u>\$ 699</u>
Effective tax rate	41%	40%	41%

Operations

We conduct our operations through fee interests, land leases and other contractual arrangements. We believe we are the largest private oil and natural gas mineral acreage holder in California, with interests in approximately 2.4 million net acres, approximately 60% of which we hold in fee. Our oil and gas leases have a primary term ranging from one to ten years, which is extended through the end of production once it commences. We also own a network of strategically placed and integral infrastructure assets, including gas plants, oil and gas gathering systems, a power plant and other related assets to maximize the value generated from our production.

Our share of production and reserves from operations in Long Beach, California are subject to contractual arrangements similar to production-sharing contracts and are in effect through the economic life of the assets. Under such contracts we are obligated to fund all capital and production costs. We record a share of production and reserves to recover such capital and production costs and an additional share for profit. Our portion of the production represents volumes: (1) to recover our partners' share of capital and production costs that we incur on their behalf and costs associated with contractually defined base production, (2) for our defined share of base production and (3) for our defined share of production in excess of base production for each period. We recover our share of capital and production costs, and generate returns, through our defined share of production from base and incremental production in (2) and (3) above. These contracts do not transfer any right of ownership to us and reserves reported from these arrangements are based on our economic interest as defined in the contracts. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline, however, our net economic benefit is greater when product prices are higher. These contracts represented approximately 16% of our production for the year ended December 31, 2014.

Results

Results for the year ended December 31, 2014 were a net loss of \$1.4 billion, compared with net income of \$869 million for the year ended December 31, 2013. The net loss in 2014 largely reflected a \$2.0 billion non-cash after-tax impairment charge for proved and unproved properties in the fourth quarter of 2014 and approximately \$64 million in after-tax charges for

rig terminations, other price-related charges and Spin-off and transition related costs. There were no similar charges or costs in 2013. Net income for 2014, excluding these charges was \$650 million as reflected in the table below.

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

	2014	2013	2012
Net income / (loss)	\$ (1,434)	\$ 869	\$ 699
Unusual and infrequent items:			
Asset impairments	3,402	—	29
Rig terminations and other price-related costs	52	—	12
Spin-off and transition related costs	55	—	—
	<u>3,509</u>	<u>—</u>	<u>41</u>
Tax effect of pre-tax adjustments	(1,425)	—	17
Core income	<u>\$ 650</u>	<u>\$ 869</u>	<u>\$ 675</u>

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

Core income for 2014, compared to 2013, benefited from higher oil production and higher realized natural gas prices, which were more than

offset by lower realized oil prices and lower realized NGL prices and volumes, and higher production costs, depreciation rates, property taxes, selling, general and administrative costs and interest expenses. In addition, unit production costs increased mainly due to higher natural gas and other energy costs, and expenses for surface operations and maintenance.

Core income for the year ended December 31, 2013 was \$869 million, compared to \$675 million for the year ended December 31, 2012. The higher income in 2013 reflected higher oil and gas prices and volumes and higher NGL volumes, partially offset by higher depreciation rates, taxes other than on income and other expenses. Production costs decreased in 2013, compared to 2012, due to a wide range of operational efficiency initiatives implemented in 2012.

The following table sets forth our average production volumes of oil, NGLs and natural gas per day for each of the three years in the period ended December 31, 2014:

	2014	2013	2012
<i>Oil (MBbl/d)</i>			
San Joaquin Basin	64	58	58
Los Angeles Basin	29	26	24
Ventura Basin	6	6	6
Sacramento Basin	—	—	—
Total	99	90	88
<i>NGLs (MBbl/d)</i>			
San Joaquin Basin	18	19	16
Los Angeles Basin	—	—	—
Ventura Basin	1	1	1
Sacramento Basin	—	—	—
Total	19	20	17
<i>Natural gas (MMcf/d)</i>			
San Joaquin Basin	180	182	204
Los Angeles Basin	1	2	3
Ventura Basin	11	11	12
Sacramento Basin	54	65	37
Total	246	260	256
Total Production (MBoe/d) (a)	159	154	148

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

(a) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas and one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, for the year ended December 31, 2014, the average prices of Brent oil and NYMEX natural gas were \$99.51 per barrel and \$4.34 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 23 to 1.

Daily oil and gas production volumes averaged 159,000 Boe for the year ended December 31, 2014, compared with 154,000 Boe for the year ended December 31, 2013. Average daily oil production increased by 9,000 Boe, or by ten percent, while daily NGLs production decreased by 1,000 Boe and natural gas decreased by 14 MMcf. The increase in oil production and decline in NGL and natural gas production reflected our emphasis on high margin oil drilling and reduction of drilling capital for natural gas. Our oil production, as well as total production, increased sequentially each quarter during 2014, reaching 105,000 barrels per day and 165,000 Boe/d, respectively, in the fourth quarter, both of which were record levels for us.

For the year ended December 31, 2013, daily oil and gas production volumes averaged 154,000 Boe, compared with 148,000 Boe for the year ended December 31, 2012. Our daily liquids production increased by 5,000 Boe while our daily natural gas production increased by 4 MMcf, or less than 700 Boe. The slight increase in our natural gas production reflected increased production from acquisitions made in 2012 and associated natural gas produced from oil drilling, partially offset by lower gas production due to reduced investment in natural gas drilling in 2013.

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

	2014	2013	2012
Oil Prices (\$ per Bbl)	\$ 92.30	\$ 104.16	\$ 104.02
NGLs Prices (\$ per Bbl)	\$ 47.84	\$ 50.43	\$ 52.76
Gas Prices (\$ per Mcf)	\$ 4.39	\$ 3.73	\$ 2.94

The following table presents our average realized prices as a percentage of WTI, Brent and NYMEX for each of the three years in the period ended December 31, 2014:

	2014	2013	2012
WTI oil	99%	106%	110%
Brent oil	93%	96%	93%
NYMEX gas	101%	102%	105%

Balance Sheet Analysis

The changes in our balance sheet as of December 31, 2014 and 2013, are discussed below:

	2014	2013
	(in millions)	
Cash and cash equivalents	\$ 14	\$ —
Trade receivables, net	\$ 308	\$ 30
Inventories	\$ 71	\$ 75
Other current assets	\$ 308	\$ 149
Property, plant and equipment, net	\$ 11,685	\$ 14,008
Other assets	\$ 111	\$ 35
Accounts payable	\$ 588	\$ 448
Accrued liabilities	\$ 318	\$ 241
Long-term debt	\$ 6,360	\$ —
Deferred income taxes	\$ 2,055	\$ 3,122
Other long-term liabilities	\$ 565	\$ 497
Equity / Net investment	\$ 2,611	\$ 9,989

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

The increase in trade receivables was largely the result of marketing our own products directly to third parties, rather than through Occidental, beginning in mid-2014. The increase in other current assets included additional California greenhouse gas emissions allowances, an increase in the current portion of our deferred tax assets, increases in joint interest receivables and the fair value of the put option purchased in December 2014.

The decrease in property, plant and equipment, net, reflected the \$3.4 billion pre-tax impairment charge for proved and unproved properties and additional depreciation, depletion and amortization (“DD&A”) in 2014, partially offset by capital investments of approximately \$2.1 billion. The increase in other assets reflected deferred debt costs incurred in 2014.

The increase in accounts payable reflected higher capital levels in the last quarter of 2014, compared to 2013. The increase in accrued liabilities included unpaid interest attributable to our 2014 borrowings. The decrease in deferred income taxes reflected the impact of the impairment charges, partially offset by accelerated tax depreciation of the capital investments in 2014. The increase in other long-term liabilities was mostly due to employee related liabilities. The decrease in equity / net investment reflected dividends and distributions to Occidental prior to the Spin-off and our net loss for the year.

Statement of Operations Analysis

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

	2014	2013	2012
	(in millions)		
Oil and natural gas sales (including related parties)	\$ 4,023	\$ 4,139	\$ 3,967
Other revenue	150	145	106
Production costs	(1,023)	(960)	(1,219)
Selling, general and administrative expenses	(336)	(292)	(273)
Depreciation, depletion and amortization	(1,198)	(1,144)	(926)
Asset impairments	(3,402)	—	(29)
Taxes other than on income	(217)	(185)	(167)
Exploration expense	(139)	(116)	(148)
Interest and debt expense, net	(72)	—	—
Other expenses	(207)	(140)	(130)
Income tax (expense) / benefit	987	(578)	(482)
Net income / (loss)	\$ (1,434)	\$ 869	\$ 699
EBITDAX ⁽¹⁾	\$ 2,548	\$ 2,733	\$ 2,296
Effective tax rate	41%	40%	41%

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

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

	2014	2013	2012
Net income / (loss)	\$ (1,434)	\$ 869	\$ 699
Interest expense	72	—	—
Income tax expense / (benefit)	(987)	578	482

Asset impairments	3,402	—	29
Depreciation, depletion and amortization	1,198	1,144	926
Exploration expense	139	116	148
Other non-cash items	51	26	—
Unusual and infrequent charges ^(a)	107	—	12
EBITDAX	<u>\$ 2,548</u>	<u>\$ 2,733</u>	<u>\$ 2,296</u>

(a) Includes rig terminations and other price-related costs, and Spin-off and transition related costs.

The following represents key metrics of our oil and gas operations, excluding certain corporate items, on a per BOE basis for the years ended December 31, 2014, 2013 and 2012:

	2014	2013	2012
Production costs	\$ 17.64	\$ 17.10	\$ 22.58
General and administrative expenses ^(a)	\$ 2.31	\$ 2.35	\$ 2.48
Other operating expenses ^(b)	\$ 0.55	\$ 0.60	\$ 0.33
Depreciation, depletion and amortization	\$ 20.40	\$ 20.11	\$ 16.82
Taxes other than on income	\$ 3.50	\$ 3.05	\$ 3.09

(a) For 2014, the amount excludes unusual and infrequent costs of \$0.10 per Boe related to Spin-off and transition related costs.

(b) For 2014, the amount excludes unusual and infrequent costs related to rig termination charges and Spin-off and transition related costs of \$0.97 per Boe. For 2012, the amount excludes rig termination charges of \$0.22 per Boe.

Year Ended December 31, 2014 vs. 2013

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

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

Production costs increased by 6%, or \$63 million to \$17.64 per Boe in 2014, compared to \$17.10 per Boe in 2013. Of this increase, \$32 million was due to higher volumes and \$31 million due to higher costs for natural gas used in our steamflood operations and higher energy costs and expenses for surface operations and maintenance. In the fourth quarter we started an aggressive cost containment program and have seen costs start to decline in December.

Selling, general and administrative expenses increased 15%, or \$44 million, in 2014 compared to 2013, mostly due to higher employee related costs and costs related to the Spin-off. They were, however, consistent with 2013 on a per barrel basis.

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

At year end 2014, we performed impairment tests with respect to our proved and unproved properties as a result of significant declines in oil prices largely during the last half of 2014. As a result, in the fourth quarter of 2014, we recorded pre-tax asset impairment charges of \$3.4 billion on proved and unproved properties throughout our asset base. The impairment charge was related to certain properties in the San Joaquin and Los Angeles basins and a portion of our assets in the Ventura basin, as well as our gas properties in the Sacramento basin. Approximately \$650 million

of the charge was related to unproved acreage. The properties were impaired as a result of accounting rules that require us to evaluate our properties based on the year-end forward price curve, as well as projects we determined we would not pursue in the foreseeable future given the current environment. We expect a substantial portion of these assets would ultimately become economical as prices recover to higher levels we view as more sustainable.

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

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

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

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

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

Year Ended December 31, 2013 vs. 2012

Oil and natural gas sales increased 4%, or \$172 million, in 2013, compared to 2012. Of this increase, \$47 million was attributable to higher oil and natural gas volumes, \$77 million was attributable to higher oil and gas prices and \$63 million was attributable to higher volumes for NGLs. The increase was partially offset by \$15 million attributable to lower prices for NGLs. Our daily liquids production increased by 5,000 Boe while our daily natural gas production increased by 4 MMcf, or less than 700 Boe. The increase in liquids production primarily reflected our strategy to increase our overall capital investment program with a focus on oil drilling while reducing drilling capital for natural gas in light of higher oil prices and lower gas prices in recent years. The slight increase in our natural gas production reflected increased production from acquisitions made in 2012 and associated natural gas produced from oil drilling, partially offset by lower natural gas production due to reduced investment in natural gas drilling in 2013.

Other revenue increased 37%, or \$39 million in 2013, compared to 2012, due to higher realized prices on third party power sales from our Elk Hills power plant.

Production costs decreased by \$259 million to \$17.10 per Boe in 2013, compared to \$22.58 per Boe for 2012, almost entirely due to a wide range of operational efficiency initiatives implemented in late 2012, including activities such as high-grading and more efficient utilization of service rigs, improved job scheduling, more efficient liquids usage and handling, optimization of field supervision and contractor usage, and reduced consumption of purchased fuel, power and field rental equipment.

Selling, general and administrative and other operating expenses increased 7%, or \$19 million, in 2013, compared to 2012, mostly due to higher compensation and employee related costs, in particular higher headcount and equity compensation in part due to the higher price of Occidental's stock.

DD&A expense increased by \$218 million. Of this increase, \$44 million was attributable to higher volumes and \$174 million was attributable to a \$3.29 per Boe increase in the DD&A rate, which was a result of additional capital investments throughout our asset base. In recent years, we have been systematically increasing our investments in IOR and EOR recovery assets and facilities. Significant investment on the front end of these projects is necessary, which has caused an increase in our DD&A rate.

Asset impairments of \$29 million in 2012 reflected the write-down of uneconomic properties in various areas, in particular natural gas properties.

Taxes other than on income increased 11%, or \$18 million, in 2013, compared to 2012, primarily due to a \$32 million increase in California greenhouse gas costs, which we began incurring at the beginning of 2013, partially offset by lower property taxes of \$14 million.

Exploration expense decreased 22%, or \$32 million, in 2013, compared to 2012, due to higher success rates resulting in lower dry hole expense of \$78 million in the San Joaquin and Los Angeles basins, partially offset by higher dry hole expense of \$14 million in the Ventura basin and higher expense of \$30 million for seismic, geological and geophysical and lease rentals.

Other expenses increased 8%, or \$10 million in 2013, compared to 2012, primarily due to higher natural gas prices for purchased natural gas

used at our Elk Hills power plant and higher rig termination costs.

Provision for income taxes increased by \$96 million due to the effect of higher pre-tax income of \$266 million, partially offset by a 1% lower effective tax rate.

Liquidity and Capital Resources

The primary source of liquidity and capital resources to fund our capital programs is cash flow from operations. Through November 2014, any excess cash generated by our business was distributed to Occidental, and our cash needs were provided by Occidental, in the form of a contribution. We expect our needs for capital investments and any potential acquisitions for at least the next twelve months will be met by cash generated from operations, and borrowings when necessary. We may, however, consider other options, such as joint ventures and similar arrangements as we work to deleverage. At December 31, 2014, we

had more than \$1.6 billion available on our revolving credit facilities, which has effectively been reduced by \$750 million under the first amendment to our credit facilities. Operating cash flows are largely dependent on oil and gas prices and differentials, sales volumes and costs. If the current conditions persist we expect our production levels will be affected as we will not look to accelerate production in this price environment.

Given the recent volatile and deteriorating oil price environment, as well as our leverage, we began a hedging program shortly after the Spin-off to protect our down-side price risk and preserve our ability to execute our capital program. In December 2014, we purchased put options with a \$50 per barrel Brent strike price, measured as a monthly average. This initial program covers almost all of our oil production for the first six months of 2015. More recently, we put into place additional hedging instruments to protect the pricing for almost two-thirds of our expected third quarter 2015 oil production. For this program we chose a combination of Brent-based collars (between \$55 and \$72) for 30,000 barrels per day for July through September as well as put options at \$50 per barrel Brent for 40,000 barrels per day in the same period. In addition, we sold a \$75 per barrel call for 30,000 barrels per day of oil production in March through June of 2015. Going forward as an independent company, we will continue to be strategic and opportunistic in implementing any hedging program. Our objective is to protect against the cyclical nature of commodity prices to provide a level of certainty around our margins and cash flows necessary to implement our investment program.

Credit Facilities

On September 24, 2014, we entered into a credit agreement with a syndicate of lenders, providing for (i) a five-year senior term loan facility (the "Term Loan Facility") and (ii) a five-year senior revolving loan facility (the "Revolving Credit Facility" and, together with the Term Loan Facility, the "Credit Facilities"). All borrowings under these facilities are subject to certain customary conditions. We amended the Credit Facilities effective as of February 25, 2015, and changed certain of our covenants through December 31, 2016 or such earlier time as we elect and demonstrate compliance with our original covenants for two successive quarters (the "Interim Covenant Period").

The aggregate initial commitments of the lenders under the Revolving Credit Facility are \$2.0 billion and under the Term Loan Facility are \$1.0 billion. The Revolving Credit Facility includes a sub-limit of \$400 million for the issuance of letters of credit. We will be required to repay the Term Loan Facility in equal quarterly installments equal to 2.5% (10.00% per annum) of the principal amount of the Term Loan Facility beginning on March 31, 2016. As of December 31, 2014, we had \$360 million outstanding under our Revolving Credit Facility with the ability to incur total net borrowings of up to \$1.25 billion during the Interim Covenant Period under this facility.

Borrowings under the Credit Facilities bear interest, at our election, at either a LIBOR rate or an alternate base rate ("ABR") (equal to the greatest of (i) the administrative agent's prime rate, (ii) the one-month LIBOR rate plus 1.00% and (iii) the federal funds effective rate plus 0.50%), in each case plus an applicable margin. This applicable margin is based on our most recent leverage ratio and will vary from (a) in the case of LIBOR loans, 1.50% to 2.25% and (b) in the case of ABR loans, from 0.50% to 1.25%. The unused portion of the Revolving Credit Facility is subject to commitment fees ranging from 0.30% to 0.50% per annum, based on our most recent leverage ratio. We also pay customary fees and expenses under the Revolving Credit Facility.

Interest payments under the Credit Facilities vary based on the borrowing options chosen. Interest on ABR loans is payable quarterly in arrears. Interest on LIBOR loans is payable at the end of each LIBOR period.

All obligations under the Credit Facilities are guaranteed jointly and severally by all of our wholly-owned material subsidiaries, and will be unsecured while we maintain our credit ratings at the minimum levels defined in the Credit Facilities. During the Interim Covenant Period, we would be required to grant security to our lenders if our corporate family ratings experienced a two-notch decline from either of our rating agencies. Outside the Interim Covenant Period we would be required to grant security in the event of a three-notch decline subject to certain exceptions described in our Credit Facilities. The assets and liabilities of subsidiaries not guaranteeing the debt are de minimis.

The Credit Facilities also require us to maintain the following financial covenants for the trailing twelve months ended as of the last day of

each fiscal quarter: (a) a leverage ratio of no more than 4.50 to 1.00 except during the Interim Covenant Period when the ratio increases by varying amounts to a maximum of 8.25 to 1.00 by December 31, 2015 and (b) an interest expense ratio of no less than 2.50 to 1.00 except as of December 31, 2015 when the ratio must be no less than 2.25 to 1.00. In addition, during the Interim Covenant Period, we must maintain an asset coverage ratio of no less than 1.05 to 1.00 measured as of the last day of each fiscal quarter. Finally, during the Interim Covenant Period, we must apply cash on hand in excess of \$250 million to repay certain amounts outstanding under the Revolving Credit Facility. If we were to breach either of these covenants the banks would be permitted to accelerate the principal amount due under the facilities. If payment were accelerated it would result in a default under the notes.

Senior Notes

On October 1, 2014, we issued \$5.00 billion in aggregate principal amount of our senior notes, including \$1.00 billion of 5% senior notes due January 15, 2020 (the "2020 notes"), \$1.75 billion of 5 1/2% senior notes due September 15, 2021 (the "2021 notes") and \$2.25 billion of 6% senior notes due November 15, 2024 (the "2024 notes" and together with the 2020 notes and the 2021 notes, the "notes"), in a private placement.

We will pay interest on the 2020 notes semi-annually in cash in arrears on January 15 and July 15 of each year, beginning on July 15, 2015. We will pay interest on the 2021 notes semi-annually in cash in arrears on March 15 and September 15 of each year, beginning on March 15, 2015. We will pay interest on the 2024 notes semi-annually in cash in arrears on May 15 and November 15 of each year, beginning on May 15, 2015.

In connection with the private placement of the notes, we granted the initial purchasers certain registration rights under a registration rights agreement. We expect to file a registration statement to register the exchange of the notes in the near future.

The indenture governing the notes includes covenants that, among other things, limit our and our restricted subsidiaries' ability to incur debt secured by liens. These covenants also restrict our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. These covenants are subject to a number of important qualifications and limitations that are set forth in the indenture. The covenants are not, however, directly linked to measures of our financial performance. In addition, if we experience a "change of control triggering event" (as defined in the indenture) with respect to a series of notes, we will be required, unless we have exercised our right to redeem the notes of such series, to offer to purchase the notes of such series at a purchase price equal to 101 percent of their principal amount, plus accrued and unpaid interest.

Spin-off Related Distributions to Occidental

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

Cash Flow Analysis

	2014	2013	2012
	(in millions)		
Net cash flows provided by operating activities	\$ 2,371	\$ 2,476	\$ 2,223
Net cash flows used in investing activities	\$ (2,312)	\$ (1,713)	\$ (2,755)
Net cash flows (used in) provided by financing activities	\$ (45)	\$ (763)	\$ 532
EBITDAX ⁽¹⁾	\$ 2,548	\$ 2,733	\$ 2,296

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

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

	2014	2013	2012
	(in millions)		
Net cash provided by operating activities	\$ 2,371	\$ 2,476	\$ 2,223
Interest expense	72	—	—
Current income taxes	165	318	(121)
Cash exploration expenses	38	44	20
Changes in operating assets and liabilities	(143)	(103)	202
Other, net	45	(2)	(28)
EBITDAX	<u>\$ 2,548</u>	<u>\$ 2,733</u>	<u>\$ 2,296</u>

Year Ended December 31, 2014 vs. 2013

Our operating cash flows in 2014 decreased by \$105 million from \$2.5 billion in 2013 to \$2.4 billion in 2014. The decrease reflected approximately \$110 million in lower sales due to lower oil and NGL prices partially offset by higher oil volumes and gas prices, higher interest expense of \$70 million, higher production costs of approximately \$65 million, higher taxes other than on income of \$30 million, higher selling, general and administrative costs of \$20 million, partially offset by lower income taxes of \$150 million and working capital changes of \$40 million in 2014 compared to 2013.

Our cash flows used in investing activities increased by approximately \$600 million in 2014, to \$2.3 billion in 2014, compared to \$1.7 billion in 2013. The increase mainly consisted of approximately \$350 million of higher capital investments and higher acquisition costs of \$240 million. The 2014 capital investments reported in the statement of cash flows exclude the effect of accruals. Total capital investments in 2014 were \$2.1 billion, of which \$2.0 billion was paid in cash during the year as reported in the statement of cash flows and \$69 million reflected an increase in capital accruals. For the years 2013 and 2012, the capital accrual amount was not material.

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

Year Ended December 31, 2013 vs. 2012

Our operating cash flows in 2013 increased by approximately \$250 million compared to 2012. The increase reflected lower operating expenses of \$250 million resulting from cost efficiencies and \$210 million in higher revenues due to higher oil and gas prices and volumes. Other significant items affecting operating cash flows consisted of higher tax payments of \$440 million and other costs of \$70 million in 2013, as well as \$300 million in positive working capital changes.

Our cash flow used in investing activities decreased by approximately \$1.0 billion in 2013 to \$1.7 billion, compared to 2012. We reduced our capital investments in 2013 by approximately \$660 million primarily due to approximately 20% lower drilling costs and lower capital needs for the Elk Hills cryogenic gas plant, which was completed during 2012. Further, our 2013 acquisitions of \$50 million were approximately \$380 million lower than the 2012 acquisition amount.

Cash used for financing activities in 2013 reflected excess cash flow distributed to Occidental. Cash provided by financing activities in 2012 reflected contributions from Occidental primarily to fund our acquisitions.

Acquisitions

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

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

paid in cash at the end of the five-year period. Through December 31, 2014, we have already fulfilled about 20% of this obligation.

During the year ended December 31, 2012, we paid approximately \$380 million for oil and gas properties including \$275 million for certain producing and non-producing assets in the Sacramento basin and undeveloped acreage in the San Joaquin basin.

Portfolio Management, 2014 Capital Program and 2015 Capital Budget

We develop our capital investment programs by prioritizing life of project returns to grow our net asset value over the long term, while balancing the short- and long-term growth potential of each of our assets. We use a Value Creation Index (“VCI”) metric for project selection and capital allocation across our portfolio of opportunities. The VCI for each project is calculated by dividing the present value of the project's pre-tax cash flow before capital over its life by the present value of the investment, using a 10% discount rate. Projects are expected to meet a VCI of 1.3, meaning that 30% of expected value is created above every dollar invested.

In 2014 we invested \$2.1 billion for projects targeting investments in the San Joaquin, Los Angeles and Ventura basins, as compared to \$1.7 billion in 2013. Virtually all of our 2014 capital investments were directed toward oil-weighted production consistent with 2013. Of the total 2014 capital program, approximately \$1.3 billion was allocated to well drilling and completions, \$181 million to workovers, \$346 million to surface support equipment to handle higher production, \$36 million to additional steam generation capacity expansion, \$100 million to exploration and the rest to maintenance capital, health, safety and environmental projects and other items.

The table below sets forth our 2014 capital investments for the year ended December 31, 2014 (in millions):

	Conventional				Unconventional		Total Capital	
	Primary	Waterflood	Steamflood	Total	Primary	Other	Investments	
Basin:								
San Joaquin	\$ 280	\$ 129	\$ 381	\$ 790	\$ 604	\$ —	\$ 1,394	
Los Angeles	3	466	—	469	—	—	469	
Ventura	82	13	8	103	1	—	104	
Sacramento	14	—	—	14	1	—	15	
Basin Total	379	608	389	1,376	606	—	1,982	
Exploration and Other	—	—	—	—	—	107	107	
Total	\$ 379	\$ 608	\$ 389	\$ 1,376	\$ 606	\$ 107	\$ 2,089	

In light of current commodity prices, our focus on creating value and our commitment to internally fund our capital budget with operating cash flows, we have significantly reduced our capital investment budget for 2015 to \$440 million, as compared to \$2.1 billion in 2014. We have focused a substantial majority of our 2015 budget on our mature steamfloods, waterfloods and capital workovers, which have much lower decline rates than many unconventional projects. We will also continue to pursue and fund our most attractive conventional and unconventional projects.

Our 2015 capital investment budget targets investments in the San Joaquin, Los Angeles and Ventura basins, and is expected to be directed towards oil-weighted production consistent with 2014. Of the total 2015 capital budget, approximately \$150 million is allocated to drilling wells, \$50 million to workovers, \$130 million to additional steam-generation capacity and compression expansion, \$15 million to exploration and the rest to 3D seismic, maintenance capital, occupational health, safety and environmental projects and other items. The table below sets forth the expected allocation of our 2015 capital budget by recovery mechanism.

	Total 2015 Capital Investments Budget (in millions)
Conventional:	
Primary recovery	\$ 40
Waterfloods	175
Steamfloods	155
Total conventional	370

Unconventional	35
Exploration	15
Corporate and other	20
Total	\$ 440

In addition, during this period of lower activity levels, we will deploy our resources to refine modern techniques that will enhance the value and growth potential of other parts of our portfolio that will not be funded in 2015 and will continue to build our inventory of available projects. This will position us to rapidly take advantage of improved market conditions when prices reach more favorable levels.

Off-Balance-Sheet Arrangements

We have no material off-balance-sheet arrangements other than those noted below.

Leases

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

Contractual Obligations

The table below summarizes and cross-references our contractual obligations as of December 31, 2014. This summary indicates on and off-balance-sheet obligations as of December 31, 2014.

	Payments Due by Year				
	Total	2015	2016 and 2017	2018 and 2019	2020 and thereafter
	(in millions)				
On-Balance Sheet					
Long-term debt (Note 5) ^(a)	\$ 6,360	\$ —	\$ 200	\$ 1,160	\$ 5,000
Other long-term liabilities ^(b)	147	6	19	16	106
Off-Balance Sheet					
Operating leases	125	13	28	26	58
Purchase obligations ^(c)	364	70	79	204	11
Total	\$ 6,996	\$ 89	\$ 326	\$ 1,406	\$ 5,175

(a) Excludes interest on the debt. As of December 31, 2014, interest on long-term debt totaling \$2.4 billion is payable in the following years (in millions): 2015 - \$312, 2016 and 2017 - \$620, 2018 and 2019 - \$608, 2020 and thereafter - \$825. The calculation of interest payable on the variable interest debt assumes the interest rate at December 31, 2014 to be the applicable interest rate for the entire term. In performing the calculation, the Revolving Credit Facility borrowings outstanding at December 31, 2014 of \$360 million were assumed to be outstanding for the entire term of the agreement.

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

(c) Amounts include payments, which will become due under long-term agreements to purchase goods and services used in the normal course of business to secure pipeline capacity, drilling rigs and services. These amounts were significantly reduced as a result of rig contract terminations in 2014. Long-term purchase contracts are discounted using a discount rate of approximately 5%.

Lawsuits, Claims, Contingencies and Commitments

We, or certain of our subsidiaries, are involved, in the normal course of business, in lawsuits, environmental and other claims and other contingencies that seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief. We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2014 and 2013 were not material to our balance sheets as of such dates. We also evaluate the amount of reasonably possible losses that we could incur as a

result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We, our subsidiaries, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with the Spin-off, purchases and other transactions that they have entered into with us. These indemnities include indemnities made to Occidental against certain tax-related liabilities that may be incurred by Occidental relating to the Spin-off and liabilities related to operation of our business while it was still owned by Occidental. As of December 31, 2014, we are not aware of circumstances that we believe would reasonably be expected to lead to indemnity claims that would result in payments materially in excess of reserves.

Critical Accounting Policies and Estimates

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

Oil and Gas Properties

The carrying value of our property, plant and equipment (“PP&E”) represents the cost incurred to acquire or develop the asset, including any asset retirement obligations, net of accumulated DD&A and any impairment charges. For assets acquired, initial PP&E cost is based on fair values at the acquisition date.

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

We determine depreciation and depletion of oil and gas producing properties by the unit-of-production method. We amortize acquisition costs over total proved reserves, and capitalized development and successful exploration costs over proved developed reserves.

Proved oil and gas reserves and production volumes are used as the basis for recording depreciation and depletion of oil and gas producing properties. Proved reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—regardless of whether deterministic or probabilistic methods are used for the estimation. We have no proved oil and gas reserves for which the determination of economic producibility is subject to the completion of major additional capital investments.

Several factors could change our proved oil and gas reserves. For example, we receive a share of production from arrangements similar to production-sharing contracts to recover costs and generally an additional share for profit. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline. Overall, our net economic benefit from these contracts is greater at higher product prices. In other cases, particularly with long-lived properties, lower product prices may lead to a situation where production of a portion of proved reserves becomes uneconomical. For such properties, higher product prices typically result in additional reserves becoming economical. Estimation of future production and development costs is also subject to change partially due to factors beyond our control, such as energy costs and inflation or deflation of oil field service costs. These factors, in turn, could lead to changes in the quantity of proved reserves. Additional factors that could result in a change of proved reserves include production decline rates and operating performance differing from those estimated when the proved reserves were initially recorded.

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

The most significant ongoing financial statement effect from a change in our oil and gas reserves or impairment of the carrying value of our proved properties would be to the DD&A rate. For example, a 5% increase or decrease in the amount of oil and gas reserves would change the

DD&A rate by approximately \$1.00 per Bbl, which would increase or decrease pre-tax income by approximately \$60 million annually based on production rates for the year ended December 31, 2014.

A portion of the carrying value of our oil and gas properties is attributable to unproved properties. At December 31, 2014, the net capitalized costs attributable to unproved properties were approximately \$300 million. While exploration and development work progresses, the unproved amounts are not subject to DD&A until they are classified as proved properties. However, if the exploration and development work were to be unsuccessful, or management decided not to pursue development of these properties as a result of lower commodity prices, higher development and operating costs, contractual conditions or other factors, the capitalized costs of the related properties would be expensed. The timing of any write-downs of these unproved properties, if warranted, depends upon management's plans, the nature, timing and extent of future exploration and development activities and their results. We believe our current plans and exploration and development efforts will allow us to realize the unproved property balance.

At year end 2014, we performed impairment tests with respect to our proved and unproved properties as a result of significant declines in oil prices largely during the last half of 2014. As a result, in the fourth quarter of 2014, we recorded pre-

tax asset impairment charges of \$3.4 billion on proved and unproved properties throughout our asset base. The impairment charge was related to certain properties in the San Joaquin and Los Angeles basins and a portion of our assets in the Ventura basin, as well as our natural gas properties in the Sacramento basin. Approximately \$650 million of the charge was related to unproved acreage. The properties were impaired as a result of accounting rules, that require us to evaluate our properties based on the year-end forward price curve, as well as projects we determined we would not pursue in the foreseeable future given the current environment. We expect a substantial portion of these assets would ultimately become economical as prices recover to higher levels we view as more sustainable.

Fair Value Measurements

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

The most significant items on our balance sheet that would be affected by recurring fair value measurements are derivatives. Based on year end 2014 amounts on the balance sheet for derivatives, a 10% increase or decrease in their fair value would affect income by \$2.4 million.

Other Loss Contingencies

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

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

Significant Accounting and Disclosure Changes

In August 2014, the Financial Accounting Standards Board ("FASB") issued rules relating to management's responsibility to evaluate and make disclosures, if applicable, regarding the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. These rules are effective for annual periods ending after December 15, 2016. They are not expected to have a material impact on our financial statements upon adoption and will require assessment on an ongoing basis.

In June 2014, the FASB issued rules for employee share-based payment awards in which the terms of the awards provide that a performance target can be achieved after the requisite service period. A performance target that affects vesting and that could be achieved after the requisite service period will be treated as a performance condition. These rules are effective for annual periods beginning on or after December 15, 2015 and are not expected to have a material impact on our financial statements upon adoption but will require assessment on an ongoing basis.

In May 2014, the FASB issued rules related to revenue recognition. Under the new rules, an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects what it expects to receive in exchange for the goods or services. The rules will also require more detailed disclosures of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The rules are effective for interim and annual periods beginning after December 15, 2016 and early application is not permitted. While we are evaluating any potential impact of these new rules, we currently believe the effect of the new rules will not have a material impact on our financial statements.

In April 2014, the FASB issued rules changing the requirements for reporting discontinued operations such that only the disposals of components of an entity that represent a strategic shift that has (or will have) a major effect on an entity's operations and financial results will be reported as discontinued operations in the financial statements. These rules are effective

for the annual periods beginning on or after December 15, 2014. They are not expected to have a material impact on our financial statements upon adoption and will require assessment on an ongoing basis.

Qualitative and Quantitative Disclosures about Market Risk

Commodity Price Risk

General

Our results are sensitive to fluctuations in oil, NGL and gas prices. Price changes at current levels of production affect our pre-tax annual income by approximately \$32 million for a \$1 per Bbl change in Brent oil prices and \$4 million for a \$1 per Bbl change in NGL prices. If natural gas prices varied by \$0.50 per Mcf, it would have an estimated annual effect on our pre-tax income of approximately \$20 million. These price-change sensitivities include the impact on income of volume changes under arrangements similar to production-sharing contracts. If production levels change in the future, the sensitivity of our results to prices also will change.

Derivatives

In February 2015, we put into place hedging instruments to protect the pricing for almost two-thirds of our expected third quarter 2015 oil production. For this program we chose a combination of Brent-based collars (between \$55 and \$72) for 30,000 barrels per day for July through September as well as put options at \$50 per barrel Brent for 40,000 barrels per day in the same period. In addition, we sold a \$75 per barrel call for 30,000 barrels per day of oil production in March through June of 2015. Going forward as an independent company, we will continue to be strategic and opportunistic in implementing any hedging program. Our objective is to protect against the cyclical nature of commodity prices to provide a level of certainty around our margins and cash flows necessary to implement our investment program.

In December 2014, we purchased put options, to hedge the risk associated with declining oil prices, for 100,000 barrels of crude oil production per day, effective on a monthly basis from January 1, 2015 through June 30, 2015. The strike price of the put option is \$50 per barrel and is tied to the Brent oil index. Changes in the intrinsic value of the put option are deferred in other comprehensive income/(loss) as a cash flow hedge until the hedged transactions are recognized in the statement of operations. Changes in the time value of the put option are marked to market through the statement of operations. The time value of the put option was valued using Level 2 inputs in the fair value hierarchy and was valued at approximately \$24 million in other current assets, as of December 31, 2014, which approximated the value of the instrument and the amount we paid the counterparty at the time the option was acquired.

In November 2012, we entered into financial swap agreements for the sale of 50 MMcf/d of our natural gas production beginning in January 2013 through March 2014. These agreements qualified as cash-flow hedges and represented approximately 5% of our 2013 total production on a Boe basis. The weighted-average strike price of these swaps was \$4.30.

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 the derivative options entered into in December 2014, we are subject to counterparty credit risk to the extent the counterparty to this derivative is unable to meet its settlement commitments. We actively manage this credit risk by selecting counterparties that we believe to be financially strong and continuing to monitor their financial health.

As of December 31, 2014, the substantial majority of the credit exposures related to our business was with investment grade counterparties. We believe exposure to credit-related losses related to our business at December 31, 2014 was not material and losses associated with credit risk have been insignificant for all years presented.

Concentration of Credit Risk

Through July 2014, substantially all of our products were sold through Occidental’s marketing subsidiaries at market prices and were settled at the time of sale to those entities. Beginning August 2014, we began marketing our own products directly to third parties. For the years ended December 31, 2014, 2013 and 2012, sales through Occidental subsidiaries accounted for approximately 65%, 97% and 97% of our net sales, respectively. For the years ended December 31, 2014, 2013 and 2012, ConocoPhillips/Phillips 66 Company and Tesoro Refining & Marketing Company LLC each accounted for more than 10% of our net sales. Collectively, they accounted for 45%, 42% and 46% in each of those years, respectively. No other customer accounted for more than 10% of our net sales during these periods.

Interest Rate Risk

Historically, we had no interest rate risk exposure as we did not have debt balances. In November 2014, we made initial borrowings on our variable-rate Credit Facilities. As of December 31, 2014, we had borrowings of \$1.0 billion outstanding under our Term Loan Facility and approximately \$360 million outstanding under our Revolving Credit Facility. A one-eighth percent change in the variable interest rates on these outstanding borrowings under our Term Loan Facility and Revolving Credit Facility would result in an approximately \$1.7 million change in annual interest expense.

The following table shows our fixed- and variable-rate debt as of December 31, 2014:

Year of Maturity	U.S. Dollar Fixed- Rate Debt	U.S. Dollar Variable- Rate Debt	Total
	(amounts in millions)		
2015	\$ —	\$ —	\$ —
2016	—	100	100
2017	—	100	100
2018	—	100	100
2019	—	1,060	1,060
Thereafter	5,000	—	5,000
Total	\$ 5,000	\$ 1,360	\$ 6,360
Weighted-average interest rate	5.63%	2.24%	4.9%
Fair Value	\$ 4,285	\$ 1,360	\$ 5,645

BUSINESS

Our Company

We are an independent oil and natural gas exploration and production company operating properties exclusively within the State of California. Our business is focused on conventional and unconventional assets, exclusively in California, which can generate positive cash flow throughout the oil and natural gas price cycle and have the capacity to provide significant production and cash flow growth in a higher price environment. We are the largest oil and gas producer in California on a gross operated basis and we believe we have established the largest privately-held mineral acreage position in the state, consisting of approximately 2.4 million net acres spanning the state’s four major oil and gas basins. We produced on average approximately 159 MBoe/d net for the year ended December 31, 2014. As of December 31, 2014, we had net proved reserves of 768 MMBoe, with approximately 72% proved developed. Oil represented 72% of our proved reserves. Our aggregate PV-10 value was \$16.1 billion. For an explanation of the non-GAAP financial measure PV-10 and a reconciliation of PV-10 to Standardized Measure, the most directly comparable GAAP financial measure, see “Reserves and Production Information” below. Our current drilling inventory comprises a diversified portfolio of oil and natural gas locations, which allows us to target drilling projects that are economically viable even in a low commodity price

environment.

Approximately 56% of our 2014 production was generated by our world-class Elk Hills and Wilmington fields. The remaining 44% was generated through a combination of conventional primary, steamflood and waterflood projects as well as unconventional projects. We develop our capital investment programs by prioritizing life of project returns to grow our net asset value over the long term, while balancing the short- and long-term growth potential of each of our assets. We use the VCI metric for project selection and capital allocation across our portfolio of opportunities. The VCI for each project is calculated by dividing the net present value of the project's pre-tax cash flow over its life by the present value of the investment, using a 10% discount rate. Projects are expected to meet a VCI of 1.3, meaning that 30% of value is created for every dollar invested.

The following table summarizes certain information concerning our acreage, wells and drilling activities (as of December 31, 2014, acres and dollars in millions, unless otherwise stated):

	Acreage		Gross Acreage Held in Fee (%)	Producing Wells, gross	Average Working Interest (%)	Identified Drilling Locations ⁽¹⁾		2015 Projected Gross Development Wells ⁽²⁾	2015 Projected Development Drilling Capital ⁽³⁾
	Gross	Net				Gross	Net		
San Joaquin Basin	1.9	1.6	58%	6,379	91%	14,450	12,600	265	96
Los Angeles Basin ⁽⁴⁾	<0.1	<0.1	49%	1,476	93%	2,000	1,900	25	54
Ventura Basin	0.3	0.3	67%	757	89%	2,350	1,800	—	—
Sacramento Basin	0.7	0.5	34%	719	80%	1,000	900	—	—
Total	2.9	2.4	53%	9,331	89%	19,800	17,200	290	150

- (1) Our total identified drilling locations include approximately 2,400 gross (2,300 net) locations associated with proved undeveloped reserves as of December 31, 2014 and 2,500 gross (2,400 net) injection well locations associated with our waterflood and steamflood projects. Our total identified drilling locations exclude 6,400 gross (5,300 net) prospective resource drilling locations. Please see "—Our Reserves and Production Information" for more information regarding the processes and criteria through which we identified our drilling locations. Of our total identified drilling locations, we believe approximately 75% are attributable to acreage owned or held by production.
- (2) Includes 55 injection wells expected to be drilled in connection with our steamflood and waterflood projects.
- (3) Includes drilling and completion expenditures of \$16 million associated with injection wells. Our total 2015 capital budget of \$440 million also includes investments in support equipment, seismic, workovers and exploration.
- (4) We currently hold approximately 40,400 gross (34,400 net) acres in the Los Angeles basin. Our Los Angeles basin operations are concentrated with pad drilling.

During 2014, we operated an average of 26 drilling rigs across the state with the majority located in the San Joaquin and Los Angeles basins. We drilled 1,048 development wells with 847 wells in the San Joaquin basin, 177

in the Los Angeles basin, 21 in the Ventura basin, and 3 in the Sacramento basin. We also drilled 9 exploration wells in the San Joaquin basin, 4 in the Ventura basin and 1 in the Sacramento basin.

As market conditions changed in the fourth quarter of 2014, we reduced our investment and drilling pace and exited the year with an active count of six drilling rigs. We currently have three active rigs with two drilling in the San Joaquin basin (targeting steamflood activities), one in the Los Angeles basin (targeting waterflood activities), and none in the Ventura and Sacramento basins. We have also reduced our workover rig count to focus on projects that meet our investment criteria in the current environment. With significant operating control of our properties, we have the ability to adjust our drilling and workover rig count in 2015 based on commodity prices and are monitoring market conditions to increase or decrease our program accordingly.

Our large acreage position contains numerous development and growth opportunities due to its varied geologic characteristics and multiple stacked pay reservoirs which, in many cases, are thousands of feet thick. We have a large portfolio of lower-risk, high-growth-potential conventional opportunities in each of our major oil and gas basins with approximately 72% of our proved reserves associated with conventional opportunities. Conventional reservoirs are capable of natural flow using primary, steamflood and waterflood recovery methods. In 2014, we targeted our capital investments primarily toward conventional development projects, including an increasing number of lower-risk steamflood recovery projects, that we expect will contribute significantly to near-term production and cash flow. We also have a significant portfolio of unconventional growth opportunities in lower permeability reservoirs which typically utilize established well stimulation techniques. We have approximately 4,800 identified drilling locations targeting unconventional reservoirs primarily in the San Joaquin basin. Over the last few years, we have continued to focus on higher-value unconventional production by exploiting seven discrete stacked pay horizons within the Monterey formation, primarily within the upper Monterey. We are seeking to duplicate our results there in the Kreyenhagen and Moreno formations which

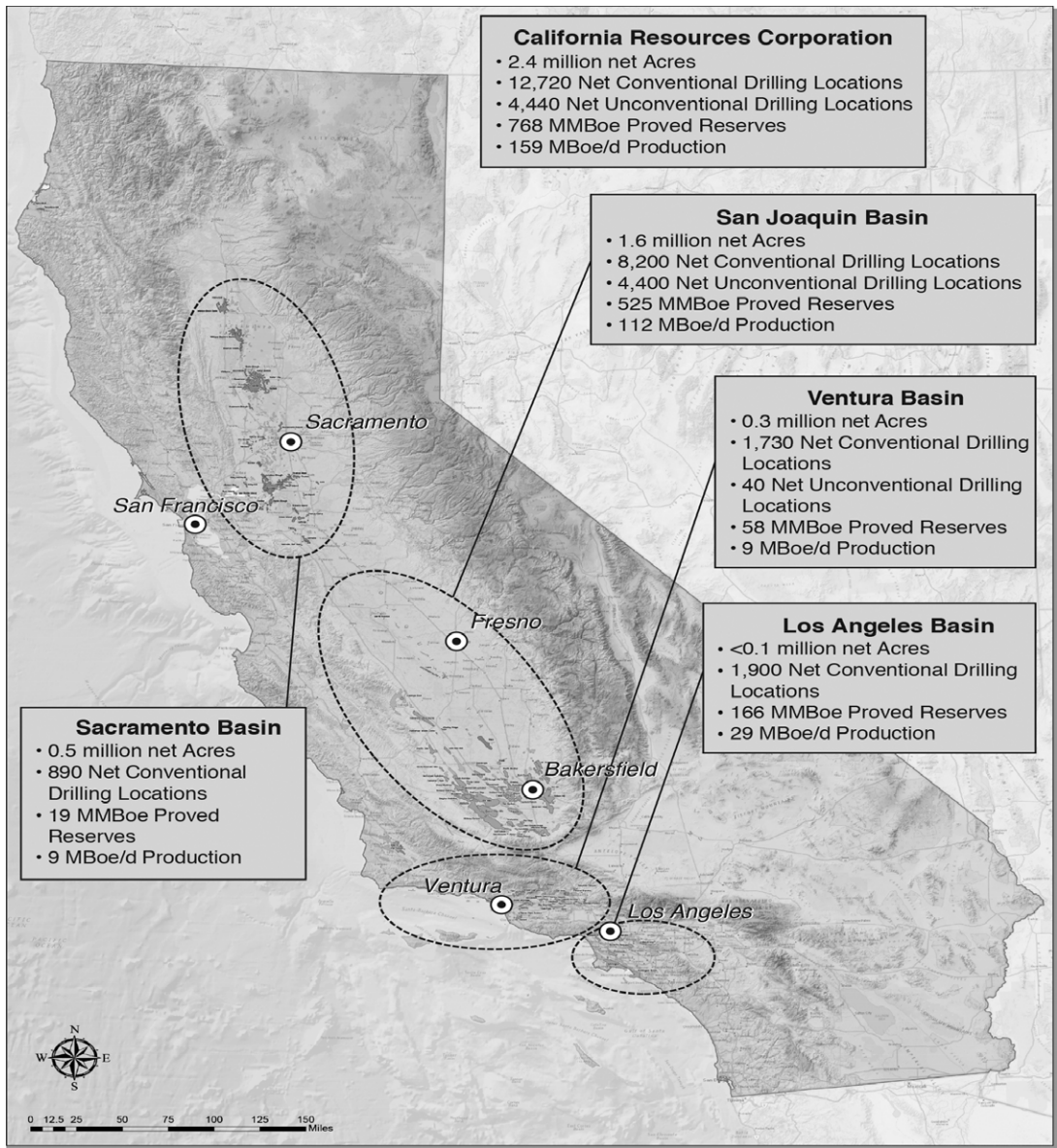
have similar geological attributes. Over the longer-term, as project economics increase, we intend to pursue development opportunities in the lower Monterey shale, which contains a variety of reservoir lithologies, but has an extremely limited production history compared to the upper Monterey.

Over the past decade, we have also built a 3D seismic library that covers over 4,250 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. In recent years we have tested and successfully implemented various exploration, drilling, completion and enhanced recovery technologies to increase recoveries, growth and returns from our portfolio.

Our Operations

Our Areas of Operation

California is one of the most prolific oil and natural gas producing regions in the world and is the third largest oil producing state in the nation. According to the California Division of Oil, Gas and Geothermal Resources (“DOGGR”), cumulative California production from all four basins in which we operate is 35 billion barrels of oil equivalent (“BBoe”), including approximately 19 BBoe in the San Joaquin basin, 10 BBoe in Los Angeles basin, 4 BBoe in Ventura basin and 10 trillion cubic feet (“Tcf”) of natural gas in Sacramento basin. Additionally, Kern County has been the largest oil producing county in the lower 48 states for a number of years. California imports more than 60% of its oil, mostly from foreign locations, and 90% of its natural gas. Because of limited crude transportation infrastructure from other parts of the country to California, the California market is generally isolated from the rest of the nation, which has typically allowed California producers to receive Brent-based prices, which are international waterborne prices. Brent prices were at a premium to WTI-based prices for comparable grades in recent years. Our operations include 137 fields with 9,331 gross active wellbores as of December 31, 2014. We believe we are the largest private oil and natural gas mineral acreage holder in California, with interests in approximately 2.4 million net acres. Approximately 60% of our total net mineral interest position is held in fee. A majority of our interests are in producing properties located in reservoirs characterized by what we believe to be long-lived production profiles with repeatable development opportunities.



Across all of our California operations, we drilled 1,048 development wells in 2014, of which 83% were producers and the rest were injectors. Our 2014 drilling capital was approximately \$1.3 billion. Our 2014 total capital of \$2.1 billion also included investments in support equipment, facilities, workovers and exploration. Our capital program added 118 MMBoe of proved reserves in 2014 representing a 203% reserve replacement ratio, calculated by using the proved reserves additions from our capital program for 2014 divided by our 2014 production of 58 MMBoe.

San Joaquin Basin

We actively operate and are developing 45 fields in this inland basin in the southern part of California's central valley which consists of conventional primary, IOR, EOR and unconventional project types with approximately 1.6 million net acres, approximately 62% of which we hold in fee. Approximately 68% of our estimated proved reserves as of December 31, 2014 and 70% of our average daily net production for the year ended December 31, 2014 were located in the San Joaquin basin.

According to DOGGR, approximately 74% of California's daily oil production for 2013 was produced in the San Joaquin basin. Commercial petroleum development began in the basin in the 1800s. Rapid discovery of many of the largest oil accumulations followed during the next several decades, including the Elk Hills field. We have been redeveloping this field and building our expertise to use in other fields across the state.

According to the U.S. Geological Survey as of 2012, the San Joaquin basin contained three of the 10 largest oil fields in the United States based on cumulative production and proved reserves. Most discovered oil accumulations occur in Eocene-age through Pleistocene-age sedimentary sections. Source rocks are organic-rich shales from the Monterey, Kreyenhagen and Tumey formations. In the 1960s, introduction of thermal techniques resulted in substantial new additions to reserves in heavy oil fields. We have been successfully developing steamfloods in our Kern Front operations, which are located next to the giant Kern River field and in the northwest portion of the Lost Hills field. Starting in the 1980s, reserves additions have continued in the Monterey formation on the west side of the basin and in our new conventional field discoveries. The basin contains multiple stacked formations throughout its areal extent, and we believe that the San Joaquin basin provides an appealing inventory of existing field re-development opportunities, as well as new play discovery and unconventional play potential. The complex stratigraphy and structure in the San Joaquin basin has allowed continuing discoveries of stratigraphic and structural traps. We believe our extensive 3D seismic library, which covers over 2,972 square miles in the San Joaquin basin, including approximately 50% of our San Joaquin acreage, will give us a competitive advantage in further exploring this basin.

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

Elk Hills

Elk Hills is one of the largest fields in the continental United States based on proved reserves and has produced over 1.6 BBoe. During the year ended December 31, 2014, we produced 64 MBoe/d on average from our Elk Hills properties, or approximately 40% of our total average daily production. Of our total Elk Hills production more than 60% is liquids. At Elk Hills, we operate efficient natural gas processing facilities with a combined capacity of over 540 MMcf/d. Additionally, we generate sufficient electricity to operate the field and sell excess power to the grid. Our operations at Elk Hills possess a state-of-the-art central control facility and remote automation control on over 95% of our wells.

Los Angeles Basin

We actively operate and are developing 10 fields in this urban, coastal basin which consists of conventional primary, IOR, EOR and unconventional project types, approximately half of which we hold in fee. Approximately 22% of our estimated proved reserves as of December 31, 2014 and 18% of our average daily net production for the year ended December 31, 2014 were located in the Los Angeles basin.

The basin is a northwest-trending plain about 50 miles long and 20 miles wide containing prolific Miocene through Pleistocene sediments. 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 named in an area of about 450 square miles. 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 Huntington and the Wilmington fields, where we have significant operations as described further below.

Wilmington Oil Field

The Wilmington field located in Long Beach is the third largest field in the United States and has produced over 2.9 BBoe. During the year ended December 31, 2014, we produced approximately 36,000 Boe/d gross on average, or 91% of the Wilmington field daily production from all producers for the year, where we operate on behalf of the State of California and the City of Long Beach. Our net production in this field equates to approximately 16% of our total average daily production. Most of our Wilmington production is covered under a set of contracts similar to production-sharing contracts under which we recover capital and operating costs and our share of profits from production. The field is developed by applying waterflood methods of oil recovery. Our waterflood operations have

attractive margins and returns in the current price environment and extend the productive life of our reservoirs beyond the economic life expected for primary development.

Ventura Basin

We actively operate and are developing 29 fields in this central California coastal basin which consists of primary conventional, IOR, EOR and unconventional project types. We currently hold approximately 0.3 million net acres in the Ventura basin, approximately 72% of which we hold in fee. Approximately 8% of our estimated proved reserves as of December 31, 2014 and approximately 6% of our average daily net production for the year ended December 31, 2014 were located in the Ventura basin.

The Ventura basin contains a Cretaceous-age to Pleistocene-age, mostly marine, sedimentary section in a major fold and thrust belt that began developing during the late Pliocene. The Ventura basin is the onshore part of the main structural feature and its offshore extension is the modern Santa Barbara basin. All of the sedimentary section is productive at various locations, and most reservoirs are sandstones with favorable porosity and permeability. In general, most traps are anticlinal, modified to some degree by faults and with significant stratigraphic trapping. The basin

contains multiple stacked formations throughout its depths, and we believe that the Ventura basin provides an appealing inventory of existing field re-development opportunities, as well as new play exploration potential.

In 2013, we completed the acquisition of, and are currently processing, the first ever 3D seismic survey in the Ventura basin. We believe this 3D seismic data gives us a competitive advantage in exploring this basin.

Sacramento Basin

We actively operate and are developing 53 fields in this inland basin in the northern part of California's central valley, primarily consisting of dry gas production. We currently hold approximately 0.5 million net acres in the Sacramento basin, approximately 35% of which we hold in fee. We believe our significant acreage position in the Sacramento basin gives us the option for future development and rapid production growth in an attractive natural gas price environment. Approximately 2% of our estimated proved reserves as of December 31, 2014 and approximately 6% of our average daily net production for the year ended December 31, 2014 were located in the Sacramento basin.

The Sacramento basin is a deep, elongated northwest-trending basin covering about 12,000 square miles. It contains a thick sequence of sedimentary deposits that range in age from the lower Cretaceous to Neogene. Exploration in the basin started in 1918.

Conventional Reservoir Recovery Methods

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

Primary Recovery

Primary recovery methods are the first techniques we use to develop a reservoir. These methods consist of drilling and producing wells without supplementing the natural energy of the reservoir. Our successful exploration program continues to provide us with primary recovery opportunities in new reservoirs or through extensions of existing fields. Our conventional development programs create future opportunities to convert these reservoirs to steamfloods or waterfloods after their primary production phase.

Steamfloods

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

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 by approximately double those experienced under primary recovery methods. Our waterflood operations have attractive margins and returns in the current price environment. These operations typically have low and predictable production declines and allow us to extend the productive life of a reservoir and significantly increase our incremental recovery after primary depletion. We use waterfloods extensively in the San Joaquin, Los Angeles and Ventura basins where they have allowed us to reduce production decline or modestly grow our production from mature fields such as Elk Hills and Wilmington.

Unconventional Reservoir Potential

We believe our undeveloped unconventional acreage has the potential to provide significant long-term production growth. In total we hold mineral interests in approximately 1.3 million net acres with unconventional potential and have identified over 4,900 gross (4,400 net) unconventional drilling locations on this acreage. As a result of focusing more on these reservoirs over the past few years, approximately 36% of

our 2014 production was from unconventional reservoirs, an increase of approximately 150% since the acquisition of our Elk Hills field properties in 1998. As of December 31, 2014, we had proved reserves of 216 MMBoe associated with our unconventional properties, with approximately 24% proved undeveloped.

We hold significant interests in the Monterey formation, which is divided into upper and lower intervals. We have successfully produced from seven discrete stacked pay horizons within the Upper Monterey. The Lower Monterey is believed to be the principal source rock within the Monterey.

We plan to apply the knowledge acquired from our successes in the upper Monterey to other shales in the San Joaquin basin such as the Kreyenhagen and Moreno formations. The Kreyenhagen and Moreno formations are hydrocarbon source rocks that have generated oil and gas, and we believe they offer similar development opportunities to the upper Monterey due to their multiple stacked pay reservoirs and general reservoir characteristics. The lower Monterey has an extremely limited production history compared to the upper Monterey, and therefore very limited knowledge exists regarding its potential. For example, only about 25 wells have been drilled into the lower Monterey to date. However, we believe we will be able to apply knowledge we gain from the upper Monterey in the lower Monterey as well.

Exploration Program

We intend to continue our active exploration program in both conventional and unconventional plays where discoveries can quickly be developed into producing fields. We believe our experienced technical staff, leading

acreage position and extensive 3D seismic library give us a strong competitive advantage. Our interpretation of this seismic data, covering a large portion of our prospective acreage, and our extensive knowledge of California geology and producing fields, has resulted in a large inventory of exploratory projects. As of December 31, 2014, our drilling inventory included 7,200 gross (5,100 net) exploration drilling locations in proven formations, the majority of which are located near existing producing fields. Additionally, we have identified 6,400 gross (5,300 net) prospective resource drilling locations in the lower Monterey, Kreyenhagen, and Moreno resource plays.

In 2014, we continued our successful near-field and impact exploration programs in conventional and unconventional reservoirs. Our exploration program delivered a geologic success rate of approximately 80% with approximately half of those successful wells determined to be commercial in the current price environment. Notable successes include our conventional reservoir drilling results in proven play trends offsetting the Pleito Ranch field in the San Joaquin basin and the Bardsdale field in the Ventura basin.

In the San Emigdio trend, two exploration wells successfully extended the Pleito Ranch field. Both wells encountered the primary producing reservoir of the Pleito Ranch field at similar reservoir depths and pressures. Additional step-out exploration prospects have been identified that can further extend this trend.

In the Ventura basin, one exploration well encountered two hydrocarbon bearing reservoir intervals and successfully extended the depth of the known producing reservoirs. We have multiple, analogous prospects in this play trend that extends for approximately 30 miles onshore in the southern Ventura basin.

We continue to develop our understanding and knowledge of the significant prospective resources in the exploration shale reservoirs. In 2014, we completed significant log, core and seismic data acquisition projects targeting the Kreyenhagen exploration shale reservoir around the Kettleman North Dome and Middle Dome fields. We completed seven workovers in existing wellbores and drilled six new wells. In many cases, zonal completions were implemented to assess the expected performance of individual zones of interest and identify landing zones for future horizontal development.

In 2015, we expect to invest approximately three percent of our capital budget, or approximately \$15 million, on exploration projects with a continued focus on prospects that can generate near-term returns. We expect exploration capital in the future to be focused in the San Joaquin, Ventura and Sacramento basins, and weighted toward projects where we have a proven track record of success.

Our Infrastructure

We own infrastructure that is integral to and significantly complements our operations. Our Elk Hills cryogenic gas plant has a capacity of 200 MMcf/d of wellhead gas bringing our total Elk Hills processing capacity to over 540 MMcf/d. We also own and operate a system of natural gas processing facilities in the Ventura basin that are capable of processing equity wellhead gas from the surrounding areas. Our natural gas processing facilities are interconnected via pipelines to nearby third-party rail and trucking facilities, with access to certain North American NGL markets. In addition, we have truck rack facilities coupled with a battery of pressurized storage tanks at our Elk Hills natural gas processing facility for NGL sales to third parties.

We generate all of our electricity needs at our Elk Hills operations, which run at about 130 megawatts, through our wholly-owned 550

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

We own an extensive network of over 20,000 miles of oil and gas gathering lines. These gathering lines are dedicated almost entirely to collect our oil and gas production and are in close proximity to field specific facilities such as tank settings or central processing sites. These lines provide a variety of services, including connecting our producing wells to gathering networks, natural gas collection and compression systems, lines for water treating and

injection services, steam supply for our thermal properties, and water lines that deliver treated water for agriculture. Nearly all of our oil is then transported through third party pipelines with flexibility to ship to various parties. In addition, virtually all of our natural gas production interconnects with major third-party natural gas pipeline systems. As a result of these connections, we typically have the ability to access multiple delivery points to improve the prices we obtain for our oil and natural gas production.

Marketing Arrangements

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

Crude Oil. Substantially all of our crude oil production is connected to California markets via our crude oil gathering pipelines which are used almost entirely for our production. We generally do not transport, refine or process the crude oil we produce and do not have any long-term crude oil transportation arrangements in place. California is heavily reliant on imported sources of energy, with over 60% of oil consumed during 2014 imported from outside the state, mostly from foreign locations. We sell all of our crude oil into the California refining markets, which we believe are among the most favorable in the U.S. Since California imports a significant percentage of its crude oil requirements, California refiners typically purchase crude oil at international waterborne-based prices that have exceeded WTI-based prices for comparable grades in recent years. Currently, we do not have any crude oil sales contracts with a term extending past 2015.

Given the recent volatile and deteriorating oil price environment, as well as our leverage, we began a hedging program shortly after the Spin-off to protect against our down-side price risk and preserve our ability to execute our capital program. In December 2014, we purchased put options with a \$50 per barrel Brent strike price, measured monthly. This initial program covers almost all of our oil production for the first six months of 2015. More recently, we put into place additional hedging instruments to protect the pricing for almost two-thirds of our expected third quarter 2015 oil production. For this program we chose a combination of Brent-based collars (between \$55 and \$72) for 30,000 barrels per day for July through September as well as put options at \$50 per barrel Brent for 40,000 barrels per day in the same period. In addition, we sold a \$75 per barrel call for 30,000 barrels per day of oil production in March through June of 2015. Going forward as an independent company, we will continue to be strategic and opportunistic in implementing any hedging program. Our objective is to protect against the cyclical nature of commodity prices to provide a level of certainty around our margins and cash flows necessary to implement our investment program.

Natural Gas. Because California imports approximately 90% of the natural gas consumed in the state, we do not have any significant interstate natural gas transportation commitments. We do have intrastate transportation capacity contracts where necessary to access markets. These contracts are required to facilitate deliveries. We sell virtually all of our natural gas production under individually negotiated contracts using market-based pricing on a monthly or shorter basis.

NGLs. We process substantially all of our NGLs through our processing plants, which facilitates access to third party delivery points near the Elk Hills field. We currently have pipeline capacity contracts to transport 10,000 barrels per day of NGLs to market and will add another 10,000 barrels per day of capacity beginning in the second quarter of 2015. We sell virtually all of our NGLs to third parties using index-based pricing. Our NGLs are generally sold pursuant to one-year contracts that are renewed annually.

Electricity. While part of the electricity output of our generation facilities is provided to our Elk Hills production facilities to reduce field operating costs and increase operational reliability, we sell a significant portion into the California market. We offer excess electricity daily into the California electricity market that is sold based on market pricing and other requirements.

Our Principal Customers

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

For the years ended December 31, 2014, 2013 and 2012, ConocoPhillips/Phillips 66 Company and Tesoro Refining & Marketing Company LLC each accounted for more than 10% of our revenue. Collectively, they accounted for 45%, 42% and 46% in each of those years, respectively.

Our Reserves and Production Information

Reserve Data

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

Reserves Presentation

Proved oil, NGLs and natural gas reserves were estimated using the unweighted arithmetic average of the first-day-of-the-month price for each month within the year, unless prices were defined by contractual arrangements. Oil, NGLs and natural gas prices used for this purpose were based on posted benchmark prices and adjusted for price differentials including gravity, quality and transportation costs. For the 2014 disclosures, the calculated average Brent oil price was \$101.30 per Bbl. The calculated average NYMEX gas price for 2014 disclosures was \$4.42 per Mcf. The realized prices used for the 2014 disclosures were \$95.20 per Bbl for oil \$49.94 per Bbl for NGLs and \$4.73 per Mcf for natural gas.

During the second half of 2014 oil prices experienced a steep decline, which has continued into 2015. If prices remain at or near current levels for the rest of 2015, or if they decline further, the prices used to determine our year-end 2015 reserves will be significantly lower than those used for year-end 2014, as mandated by SEC regulations. Under such circumstances, we may experience significant negative price-related revisions to our proved reserves at year-end 2015. For example, under a much lower price scenario used for reserves reporting purposes, a significant portion of our proved undeveloped reserves may no longer meet the economic producibility criteria under the rules. Similarly, while we have significant control over variable costs, certain costs in our long-lived fields, such as Elk Hills, are fixed, having the effect of increasing costs on a per barrel basis in later years as production declines, rendering them uneconomic in a lower price environment. We would expect that our production-sharing type contracts would partially offset these negative revisions. Further, we believe that a prolonged period of low oil prices would result in lower operating costs, which would tend to mitigate price related negative revisions to some extent by improving the economics of proved undeveloped reserves as well as extending the economic lives of long-lived fields.

The following tables summarize our estimated proved reserves and related PV-10 and Standardized Measure at December 31, 2014. Reserves are stated net of applicable royalties. Estimated reserves include our economic interests under arrangements similar to production-sharing contracts relating to the Wilmington field in Long Beach.

As of December 31, 2014					
	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Proved developed reserves:					
Oil (MMBbl)	229	124	34	—	387
NGLs (MMBbl)	62	—	2	—	64
Natural Gas (Bcf)	458	11	28	110	607
Total (MMBoe) ⁽¹⁾⁽²⁾	367	126	41	18	552
Proved undeveloped reserves:					
Oil (MMBbl)	111	39	14	—	164
NGLs (MMBbl)	20	—	1	—	21
Natural Gas (Bcf)	163	5	9	6	183

Total (MMBoe) ⁽²⁾	158	40	17	1	216
Total proved reserves:					
Oil (MMBbl)	340	163	48	—	551
NGLs (MMBbl)	82	—	3	—	85
Natural Gas (Bcf)	621	16	37	116	790
Total (MMBoe) ⁽²⁾	525	166	58	19	768

- (1) Approximately 11% of proved developed oil reserves, 5% of proved developed NGLs reserves, 9% of proved developed natural gas reserves and 10% of total proved developed reserves are non-producing.
- (2) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of gas and one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2014, the average prices of Brent oil and NYMEX natural gas were \$99.51 per Bbl and \$4.34 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 23 to 1.

PV-10 and Standardized Measure

	At December 31, 2014
PV-10 of proved reserves (in millions) ⁽¹⁾	\$ 16,091
Standardized measure (in millions)	\$ 10,828

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

The following table provides a reconciliation of our Standardized Measure to PV-10:

	At December 31, 2014
	(in millions)
PV-10	\$ 16,091
Present value of future income taxes discounted at 10%	(5,263)
Standardized Measure of Discounted Future Net Cash Flows	\$ 10,828

Proved Reserve Additions

Our total proved reserve additions from all sources were 82 MMBoe in 2014. Of these reserve additions, 118 MMboe were the result of our capital program and 6 MMBoe as a result of property acquisitions. These additions were partially offset by 42 MMBoe of negative revisions. The total additions to our proved reserves during the year ended December 31, 2014 were as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Improved recovery:					
Oil (MMBbl)	70	11	4	—	85
NGLs (MMBbl)	13	—	—	—	13
Natural Gas (Bcf)	107	—	2	5	114
Total (MMBoe)	101	11	4	1	117
Extensions and discoveries:					
Oil (MMBbl)	1	—	—	—	1
NGLs (MMBbl)	—	—	—	—	—
Natural Gas (Bcf)	—	—	—	—	—
Total (MMBoe)	1	—	—	—	1
Total reserve additions from capital program	102	11	4	1	118
Revisions of previous estimates⁽¹⁾:					
Oil (MMBbl)	(41)	8	(4)	—	(37)
NGLs (MMBbl)	8	—	—	—	8
Natural Gas (Bcf)	(91)	—	4	7	(80)
Total (MMBoe)	(48)	8	(3)	1	(42)
Acquisitions:					
Oil (MMBbl)	1	—	5	—	6
NGLs (MMBbl)	—	—	—	—	—
Natural Gas (Bcf)	—	—	2	—	2
Total (MMBoe)	1	—	5	—	6
Total proved reserve additions					
Oil (MMBbl)	31	19	5	—	55
NGLs (MMBbl)	21	—	—	—	21
Natural Gas (Bcf)	16	—	8	12	36
Total (MMBoe)	55	19	6	2	82

(1) Of these, (1) MMBOE were price-related.

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

Improved Recovery

In 2014, we added proved reserves of 117 MMBoe from improved recovery through proven IOR and EOR methods, as well as unconventional primary mechanisms. The improved recovery additions in 2014 were mainly associated with the continued development of properties in the San Joaquin and Los Angeles basins. These properties comprise both conventional and unconventional projects. The types of conventional IOR and EOR development methods we use can be applied through existing wells, though additional drilling is frequently required

to fully optimize the development configuration. Many of our projects, including unconventional projects, rely on improving permeability to increase flow in the wells. In addition, some improved recovery comes from drilling infill wells that allow recovery of reserves that would not be recoverable from existing wells.

Extensions and Discoveries

We also added 1 MMBoe of proved reserves from extensions and discoveries, which generally result from exploration and exploitation programs.

Revisions of Previous Estimates

Revisions can include upward or downward changes to previous proved reserve estimates due to the evaluation or interpretation of geologic, production decline or operating performance data. In addition, product price changes affect proved reserves we record. For example, higher prices may increase the economically recoverable reserves, because the extra margin extends the expected life of the operations. Offsetting this effect, higher prices slightly decrease our share of proved reserves under arrangements similar to production-sharing contracts at our Long Beach operations because less oil is required to recover costs. Conversely, when prices drop, our share of proved reserves slightly increases for such arrangements similar to production-sharing contracts and economically recoverable reserves may drop for other operations. The negative revisions of 42 MMBoe were mainly the result of performance related adjustments to several legacy projects concentrated in the San Joaquin basin, primarily in Elk Hills.

Proved Undeveloped Reserves

In 2014, we had proved undeveloped reserve additions of 89 MMBoe from improved recovery, primarily in the San Joaquin and Los Angeles basins, partially offset by 24 MMBoe of negative revisions. We also transferred 81 MMBoe of proved undeveloped reserves to the proved developed category as a result of the 2014 development programs, of which 98% were in the San Joaquin and Los Angeles basins. We invested approximately \$1.2 billion in 2014 to convert proved undeveloped reserves to proved developed reserves. The total changes to our proved undeveloped reserves during the year ended December 31, 2014 were as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Improved recovery:					
Oil (MMBbl)	56	8	2	—	66
NGLs (MMBbl)	9	—	—	—	9
Natural Gas (Bcf)	80	—	1	—	81
Total (MMBoe)	79	8	2	—	89
Extensions and discoveries:					
Oil (MMBbl)	1	—	—	—	1
NGLs (MMBbl)	—	—	—	—	—
Natural Gas (Bcf)	—	—	—	—	—
Total (MMBoe)	1	—	—	—	1
Revisions of previous estimates:					
Oil (MMBbl)	(13)	(2)	(4)	—	(19)
NGLs (MMBbl)	2	—	—	—	2
Natural Gas (Bcf)	(40)	—	(2)	—	(42)
Total (MMBoe)	(18)	(2)	(4)	—	(24)
Acquisitions:					
Oil (MMBbl)	—	—	1	—	1
NGLs (MMBbl)	—	—	—	—	—

Natural Gas (Bcf)	—	—	—	—	—
Total (MMBoe)	—	—	1	—	1
Transfers to proved developed reserves:					
Oil (MMBbl)	(39)	(13)	(2)	—	(54)
NGLs (MMBbl)	(11)	—	—	—	(11)
Natural Gas (Bcf)	(93)	(2)	(1)	(1)	(97)
Total (MMBoe)	(66)	(13)	(2)	—	(81)
Proved undeveloped reserve changes, net of transfers:					
Oil (MMBbl)	5	(7)	(3)	—	(5)
NGLs (MMBbl)	—	—	—	—	—
Natural Gas (Bcf)	(53)	(2)	(2)	(1)	(58)
Total (MMBoe)	(4)	(7)	(3)	—	(14)

Reserves Evaluation and Review Process

Our estimates of proved reserves and associated future net cash flows as of December 31, 2014 were made by our technical personnel 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. This process involves reservoir engineers, geoscientists, planning engineers and financial analysts. As part of the proved reserves estimation process, all reserve volumes are estimated by a forecast of production rates, operating costs and capital investments. Price differentials between specified benchmark prices and realized prices and specifics of each operating agreement are then used to estimate the net reserves. Production rate forecasts are derived by a number of methods, including estimates from decline-curve analysis, type-curve analysis, material balance calculations that take into account the volumes of substances replacing the volumes produced and associated reservoir pressure changes, seismic analysis and computer simulation of the reservoir performance. These field-tested technologies have demonstrated reasonably certain results with consistency and repeatability in the formations being evaluated or in analogous formations. Operating and capital costs are forecast using the current cost environment applied to expectations of future operating and development activities related to the proved reserves.

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

Our Vice President, Reserves and Corporate Development assumed primary responsibility for overseeing the preparation of our reserve estimates in connection with the Spin-off. She has over 14 years of experience as an energy sector engineer including as a Senior Reservoir Engineer with Ryder Scott. She is a member of the Society of Petroleum Engineers, for which she served as past chair of the U.S. Registration Committee. She holds a Master of Engineering in Petroleum Engineering from the University of Houston and a Bachelor of Science from the University of Florida and is a registered engineer in the State of Texas.

We have an Oil and Gas Reserves Review Committee (“Reserves Committee”), consisting of senior corporate officers, which reviewed and approved our oil and natural gas reserves for 2014. The Reserves Committee reports to our Audit Committee during the year. Ryder Scott was retained to separately review the oil and natural gas reserves estimation processes used in 2014 for our properties and to provide the opinion noted below.

Ryder Scott conducted a process review of the methods and analytical procedures used by our engineering and geological staff to estimate the proved reserves volumes, prepare the economic evaluations and determine reserves classifications as of December 31, 2014. Ryder Scott reviewed the specific application of such methods and procedures for selected oil and gas properties considered to be a valid representation of our 2014 year-end total proved reserves portfolio. In 2014, Ryder Scott reviewed approximately 32% of our proved oil and natural gas reserves. Since being engaged by our former parent in 2003, Ryder Scott has reviewed the specific application of reserve estimation methods and procedures for approximately 88% of our proved oil and natural gas reserves that existed at December 31, 2014. Ryder Scott was retained to provide objective third-party input on the methods and procedures used to estimate our oil and natural gas reserves for 2014 and to gather industry information

applicable to the reserve estimation and reporting process for those reserves. Ryder Scott was not engaged to render an opinion as to the reasonableness of our reserves quantities. We filed Ryder Scott's independent report as an exhibit to the registration statement of which this prospective is a part.

Based on its reviews, including the data, technical processes and interpretations presented with respect to our oil and natural gas reserves, Ryder Scott concluded that the overall procedures and methodologies utilized in estimating the proved reserves volumes, documenting the changes in reserves from prior estimates, preparing the economic evaluations and determining the reserves classifications for the reviewed properties are appropriate for the purpose thereof and comply with current SEC regulations.

Because the Spin-off occurred in late 2014, we used Occidental's established reserves review process described above to estimate our 2014 proved reserves. Following the 2014 reserve estimation, we intend to rely more heavily on independent reserves estimation companies, such as Ryder Scott, to estimate our proved reserves volumes.

Determination of Identified Drilling Locations

Proven Drilling Locations

Based on our reserves report as of December 31, 2014, we have approximately 2,400 gross (2,300 net) drilling locations attributable to our proved undeveloped reserves. We use production data and experience gained from our development programs to identify and prioritize this proven drilling inventory. These drilling locations are included in our inventory only after they have been evaluated technically and are deemed to have a high likelihood of being drilled within a five-year time frame. As a result of rigorous technical evaluation of geologic and engineering data, it can be estimated with reasonable certainty that reserves from these locations will be commercially recoverable in accordance with SEC guidelines. Management considers the availability of local infrastructure, drilling support assets, state and local regulations and other factors it deems relevant in determining such locations.

Unproven Drilling Locations

We have also identified a multi-year inventory of 10,200 gross (9,800 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

Our portfolio of prospective drilling locations contains approximately 7,200 gross (5,100 net) unrisks exploration drilling locations in proven formations, the majority of which are located near existing producing fields. We use internally generated information and proprietary models consisting of data from analog plays, 3D seismic data, open-hole and mud log data, cores, and reservoir engineering data to help define the extent of the targeted intervals and the potential ability of such intervals to produce commercial quantities of hydrocarbons. Information used to identify exploration locations includes both our own proprietary data as well as industry data available in the public domain. After defining the reservoir target area, we identified our exploration drilling locations within the applicable intervals by applying the well spacing we have historically utilized for the applicable type of recovery process used.

Prospective Resource Drilling Locations

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

Well Spacing Determination

Our well spacing determinations in the above categories of identified well locations are based on actual operational spacing within our existing producing fields, which we believe are reasonable for the particular recovery

process employed (i.e., primary, waterflood or EOR). Due to the significant vertical thickness and multiple stacked reservoirs usually encountered by our drilling wells, typical well spacing is generally less than 20 acres and often 10 acres or less in the majority of our fields unless specified differently above. These parameters also meet the general well spacing restrictions imposed on certain oil and gas fields in California.

Drilling Schedule

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

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

The table below sets forth our total gross identified drilling locations as of December 31, 2014, excluding our prospective drilling locations from new resource plays.

	Proven Drilling Locations		Total Identified Drilling Locations	
	Oil and Natural Gas Wells	Injection Wells	Oil and Natural Gas Wells	Injection Wells
San Joaquin Basin				
Primary Conventional	150	—	3,900	—
Steamflood	900	250	3,100	900
Waterflood	100	50	1,000	700
Unconventional	300	—	4,550	300
San Joaquin Basin subtotal	1,450	300	12,550	1,900
Los Angeles Basin				
Primary Conventional	—	—	50	—
Steamflood	—	—	—	—
Waterflood	300	150	1,300	650
Unconventional	—	—	—	—
Los Angeles Basin subtotal	300	150	1,350	650
Ventura Basin				
Primary Conventional	50	—	1,650	—
Steamflood	15	—	200	—
Waterflood	50	50	200	250
Unconventional	2	—	50	—
Ventura Basin subtotal	117	50	2,100	250
Sacramento Basin				
Primary Conventional	1	—	1,000	—
Sacramento Basin subtotal	1	—	1,000	—
Total Identified Drilling Locations	1,868	500	17,000	2,800

Production, Price and Cost History

Oil, NGLs and natural gas are commodities; therefore, the price that we receive for our production is largely a function of market supply and demand. Product prices are affected by a variety of factors, including changes in consumption patterns, global and local (particularly for natural gas) economic conditions the actions of OPEC and other oil and natural gas producing countries, inventory levels, actual or threatened production disruptions, currency exchange rates, worldwide drilling and exploration activities, the effects of conservation, weather, geophysical and technical limitations, refining and processing disruptions, transportation bottlenecks and other matters affecting the supply and demand dynamics of oil, natural gas and NGLs, and the effect of changes in market perceptions. We have only occasionally hedged commodity price risk. However, given the recent steep decline in oil prices, we recently started a hedging program to protect against our down-side price risk and preserve our ability to execute our capital program in 2015.

The following table sets forth information regarding production, realized and benchmark prices, and production costs for oil and gas producing activities for the years ended December 31, 2014, 2013 and 2012. For additional information on price calculations, see information set forth in “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

	Year Ended December 31,		
	2014	2013	2012
Production Data:			
Oil (MBbl/d)	99	90	88
NGLs (MBbl/d)	19	20	17
Natural gas (MMcf/d)	246	260	256
Average daily combined production (MBoe/d)	159	154	148
Total combined production (MMBoe)	58	56	54
Average realized prices:			
Oil (per Bbl)	\$ 92.30	\$ 104.16	\$ 104.02
NGLs (per Bbl)	\$ 47.84	\$ 50.43	\$ 52.76
Natural gas (per Mcf)	\$ 4.39	\$ 3.73	\$ 2.94
Average Benchmark prices:			
WTI oil (\$/Bbl)	\$ 93.00	\$ 97.97	\$ 94.21
Brent oil (\$/Bbl)	\$ 99.51	\$ 108.76	\$ 111.70
NYMEX gas (\$/Mcf)	\$ 4.34	\$ 3.66	\$ 2.81
Average costs per Boe:			
Production costs	\$ 17.64	\$ 17.10	\$ 22.58
General and administrative expenses ^(a)	\$ 2.31	\$ 2.35	\$ 2.48
Other operating expenses ^(b)	\$ 0.55	\$ 0.60	\$ 0.33
Depreciation, depletion and amortization	\$ 20.40	\$ 20.11	\$ 16.82
Taxes other than on income	\$ 3.50	\$ 3.05	\$ 3.09

(a) For 2014, the amount excludes unusual and infrequent costs of \$0.10 per Boe related to Spin-off and transition related costs.
(b) For 2014, the amount excludes unusual and infrequent costs related to rig termination charges and Spin-off and transition related costs of \$0.97 per Boe. For 2012, the amount excludes rig termination charges of \$0.22 per Boe.

The following table sets forth information regarding production, realized prices, and production costs for our largest two fields, Elk Hills and Wilmington, for the years ended December 31, 2014, 2013 and 2012.

	Elk Hills			Wilmington		
	2014	2013	2012	2014	2013	2012
Production data:						
Oil (MBbl/d)	25	26	29	25	22	21
NGLs (MBbl/d)	16	18	15	—	—	—
Natural gas (MMcf/d)	136	145	168	—	—	—
Average realized prices:						
Oil (MBbl/d)	\$ 97.27	\$ 106.32	\$ 101.19	\$ 90.37	\$ 103.29	\$ 102.15
NGLs (MBbl/d)	\$ 48.68	\$ 49.62	\$ 53.19	\$ —	\$ —	\$ —
Natural gas (MMcf/d)	\$ 4.47	\$ 3.67	\$ 2.86	\$ —	\$ —	\$ —
Production costs per Boe	\$ 14.31	\$ 12.34	\$ 16.46	\$ 28.98	\$ 31.56	\$ 35.13

Note: Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2014, the average prices of Brent oil and NYMEX natural gas were \$99.51 per Bbl and \$4.34 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 23 to 1.

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

	Total Proved Reserves		Average Net Daily Production(MBoe/d)
	MMBoe	Oil (%)	Year Ended December 31, 2014
San Joaquin Basin			
Primary Conventional	70	72%	18
Waterfloods	60	76%	7
Steamfloods ^(a)	181	100%	30
Unconventional	214	33%	57
San Joaquin Basin subtotal	525	65%	112
Los Angeles Basin			
Primary Conventional	—	—%	—
Waterfloods	166	99%	29
Steamfloods	—	—%	—
Unconventional	—	—%	—
Los Angeles Basin subtotal	166	99%	29
Ventura Basin			
Primary Conventional	31	80%	6
Waterfloods	25	87%	2
Steamfloods	—	—%	—
Unconventional	2	61%	1
Ventura Basin subtotal	58	83%	9

Sacramento Basin

Primary Conventional	19	—%	9
Sacramento Basin subtotal	19	—%	9
Total	768	72%	159

(a) Includes reserves and production from gas injection of 9% and 5%, respectively.

Productive Wells

As of December 31, 2014, we had a total of 9,331 gross (8,384 net) producing wells, approximately 90% of which were oil wells. Our average working interest in our producing wells is approximately 90%. Many of our oil wells produce associated natural gas and some of our natural gas wells also produce condensate and NGLs.

The following table sets forth our productive oil and natural gas wells (both producing and capable of production) as of December 31, 2014.

	San Joaquin Basin		Los Angeles Basin		Ventura Basin		Sacramento Basin		Total	
Oil										
Gross ^{(a)(b)}	10,106	(1,057)	1,943	(56)	1,602	(61)	—	—	13,651	(1,174)
Net ^{(a)(c)}	8,994	(817)	1,835	(51)	1,590	(59)	—	—	12,419	(927)
Natural Gas										
Gross ^{(a)(b)}	293	(110)	8	—	—	—	1,345	(52)	1,646	(162)
Net ^{(a)(c)}	248	(84)	8	—	—	—	1,260	(50)	1,516	(134)

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

Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we owned an interest as of December 31, 2014, of which approximately 60% is held in fee. Of the 40% that is leased approximately 35% was held by production at December 31, 2014.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
	(in thousands)				
Developed ⁽¹⁾					
Gross ⁽²⁾	416	24	70	271	781
Net ⁽³⁾	379	20	69	248	716
Undeveloped ⁽⁴⁾					
Gross ⁽²⁾	1,460	16	232	386	2,094
Net ⁽³⁾	1,187	14	191	299	1,691

- (1) Acres spaced or assigned to productive wells.
- (2) Total acres in which we hold an interest.
- (3) Sum of fractional interests owned based on working interests or interests under arrangements similar to production-sharing contracts.
- (4) Acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether the acreage contains proved reserves.

Work programs are designed to ensure that the exploration potential of any leased property is fully evaluated before expiration. In some instances, we may relinquish leased acreage in advance of the contractual expiration date if the evaluation process is complete and there is not a business basis for extension. In cases where additional time may be required to fully evaluate acreage, we have generally been successful in obtaining extensions. The combined net acreage covered by leases expiring in the next three years represents 23% of our total net undeveloped acreage at December 31, 2014 and these expirations would not have a material adverse impact on us. Historically, we have not dedicated any significant portion of our capital to prevent lease expirations and do not expect we will need to do so in the future.

Participation in Exploratory and Development Wells Being Drilled

The following table sets forth our participation in exploratory and development wells being drilled as of December 31, 2014.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Exploratory and development wells					
Gross	3	8	—	1	12
Net	3	8	—	1	12

At December 31, 2014, we were participating in eight steamflood and 40 waterflood projects. All of the significant steamflood projects were located in the San Joaquin basin. Twenty-five waterflood projects were located in the Los Angeles basin and 15 in the San Joaquin basin.

Drilling Activity

The following table describes our drilling activity for the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Net wells represent the sum of fractional interests in wells in which we own an interest.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
2014					
Oil					
Exploratory	2.0	—	1.7	—	3.7
Development	775.2	170.2	20.3	—	965.7
Natural Gas					
Exploratory	—	—	—	—	—
Development	—	—	—	3.0	3.0
Dry					
Exploratory	8.0	—	2.0	1.0	11.0
Development	2.3	0.9	—	—	3.2
2013					
Oil					
Exploratory	2.0	—	—	—	2.0
Development	543.1	125.7	18.8	—	687.6
Natural Gas					
Exploratory	—	—	—	—	—

Development	—	—	—	7.7	7.7
Dry					
Exploratory	5.0	—	1.0	1.0	7.0
Development	2.5	0.9	—	—	3.4
2012					
Oil					
Exploratory	8.0	—	2.0	—	10.0
Development	485.7	121.4	63.9	—	671.0
Natural Gas					
Exploratory	1.0	—	—	—	1.0
Development	2.5	—	—	3.0	5.5
Dry					
Exploratory	11.0	—	—	—	11.0
Development	4.0	—	—	—	4.0

Delivery Commitments

We have made commitments to certain refineries and other buyers to deliver oil, natural gas and NGLs. As of December 31, 2014, the total amount contracted to be delivered is approximately 34 MBbls/d of oil under 60-day contracts, 2 Bcf of natural gas under 90-day contracts, and 1 MMBbls of NGLs through March 2015. These are index-based contracts with prices set at the time of delivery at benchmark prices. We have significantly more production capacity than the amounts committed and have the ability to secure additional volumes in case of a shortfall. None of the commitments in any given year is expected to have a material impact on our financial statements.

Title to Our Properties

As is customary in the oil and natural gas industry, we initially conduct a high level review of the title to our properties at the time of acquisition. Prior to the commencement of drilling operations on those properties, we conduct a more thorough title examination and perform curative work with respect to significant defects. We generally will not commence drilling operations on a property until we have cured known title defects that are material to the project. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of our properties. Burdens on properties may include customary royalty interests,

liens incident to operating agreements and for current taxes, obligations or duties under applicable laws, development obligations, or net profits interests among others.

Competition

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

Regulation of the Oil and Natural Gas Industry

Our operations are subject to complex and stringent federal, state, local and other laws and regulations relating to the exploration and development of our properties, the production, transportation, and sale of our products, and the services we provide.

Regulation of Exploration and Production

California has regulations governing:

- the conservation of oil and natural gas, including provisions for the unitization or pooling of oil and natural gas properties;
- oil and natural gas production, including well spacing or density, on private and state lands;
- methods of drilling, constructing and completing wells;

- well stimulation techniques such as hydraulic fracturing and acid matrix stimulation;
- design, construction, operation and maintenance of facilities, such as natural gas processing plants, power plants, compressors and pipelines;
- improved or enhanced recovery techniques such as fluid injection for waterflooding or steamflooding;
- sourcing and disposal of water used in the drilling, completion, stimulation and enhanced recovery processes;
- posting of bonds or other financial assurance to drill or operate wells and facilities;
- imposition of taxes and fees with respect to our properties and operations; and
- occupational health, safety and environmental matters and the transportation and sale of our products as described below.

DOGGR is the State’s primary regulator of the oil and natural gas industry on private and state lands, with additional oversight from the State Lands Commission’s administration of state surface and mineral interests. The federal Bureau of Land Management of the U.S. Department of the Interior exercises similar jurisdiction on federal lands in California. In addition, specific aspects of our operations, such as occupational health, safety, air or water quality, labor, marketing and taxation, are regulated by other federal, state or local agencies. Collectively, the effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill to levels below those that would otherwise be possible.

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

- new permitting of defined well stimulation treatments;

- prior notification to proximate property owners or lessees of proposed stimulation treatments, and pre- and post-stimulation groundwater sampling as requested by the owner or lessee;
- monitoring of groundwater quality in areas where well stimulation treatments occur, or concurrence that monitoring is not warranted due to a lack of protected water as defined by SB 4;
- public disclosure of stimulation data, including data that may be considered proprietary or trade secret; and
- state agencies to prepare an environmental impact report and scientific studies regarding well stimulation.

The initial implementation of interim well stimulation regulations under SB 4 in 2014 delayed certain operations, and the State’s implementation of final SB 4 regulations and associated studies and reports may increase costs and cause additional delays.

Finally, the Safe Drinking Water Act and comparable state laws regulate the injection of produced water, steam or carbon dioxide into underground reservoirs for enhanced oil recovery or disposal. If the existing underground injection program is changed then our ability to inject produced water may be curtailed and our development and production activities may be negatively affected.

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

Regulation of Health, Safety and Environmental Matters

Numerous federal, state, local, and other laws and regulations that govern health and safety, the release or discharge of materials, land use or environmental protection may restrict the use of our properties and operations, increase costs or lower demand for or restrict the use of our products and services. Applicable federal health, safety and environmental laws include, but are not limited to, the Occupational Safety and Health Act, Clean Air Act, Clean Water Act, Safe Drinking Water Act, Oil Pollution Act, Natural Gas Pipeline Safety Act, Pipeline Safety Improvement Act, Pipeline Safety, Regulatory Certainty, and Job Creation Act, National Environmental Policy Act, Endangered Species Act, Migratory Bird Treaty Act, Comprehensive Environmental Response, Compensation, and Liability Act, Resource Conservation and Recovery Act and National Environmental Policy Act. California imposes additional laws that are analogous to, and often more stringent than, such federal laws. These laws

and regulations:

- require various permits and approvals before drilling, workovers, production, underground fluid injection, or solid and hazardous waste disposal commences, or before facilities are constructed or put into operation;
- require the installation of sophisticated safety and pollution control equipment to prevent or reduce releases or discharges of regulated materials to air, land, surface water or ground water;
- restrict the use, types or sources of water, energy, land surface, habitat or other natural resources, require conservation measures, and impose energy efficiency or renewable energy standards;
- restrict the types, quantities, and concentrations of regulated materials, including, without limitation, oil, natural gas, produced water or wastes, that can be released or discharged into the environment in connection with drilling, production, processing, power generation or transportation activities;
- limit or prohibit operations on lands lying within coastal, wilderness, wetlands, groundwater recharge, endangered species habitat and other protected areas;

- establish standards for the closure, abandonment, cleanup or restoration of former operations, such as plugging of abandoned wells and decommissioning of facilities;
- impose substantial liabilities for unauthorized releases or discharges of regulated materials into the environment with respect to our current or former properties and operations and other locations where such materials or wastes generated by us or our predecessors were released or discharged;
- require comprehensive environmental analyses, recordkeeping and reports with respect to operations affecting federal, state and private lands or leases;
- impose taxes or fees with respect to the foregoing matters;
- may expose us to litigation by governmental authorities, special interest groups and other claimants; and
- may restrict the rate of oil, NGLs, natural gas and electricity production below the rate that would otherwise be possible.

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

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

Regulation of Climate Change and Greenhouse Gas ("GHG") Emissions

A number of international, federal, state, and regional efforts seek to prevent or mitigate the effects of climate change or to track or reduce GHG emissions associated with industrial activity, including operations of the oil and natural gas production sector and those who use our products as a source of energy. The U.S. Environmental Protection Agency has adopted regulations to restrict GHG emissions from certain mobile sources, require certain operations, including onshore and offshore oil and natural gas production facilities, to monitor and report GHG emissions on an annual basis, and incorporate measures to reduce GHG emissions in permits for certain facilities.

In 2006, California adopted Assembly Bill 32 ("AB 32"), which established a statewide "cap-and-trade" program for GHG emissions. Under the program, which commenced in 2012, the California Air Resources Board ("CARB") set a statewide maximum limit on total GHG emissions, and this cap declines annually through 2020. CARB requires us, and other businesses in the oil and natural gas production sector, to report GHG emissions. We are required to obtain allowances or qualifying offset credits for each metric ton of GHGs emitted from our operations and from the sale of certain products to customers for use in California. The state grants a portion of the allowance, but we must make up any shortfall by

purchasing additional allowances from either the state or a third party. The availability of allowances will decline over time, and the cost to acquire such allowances may increase. The cap-and-trade program currently expires in 2020. A California Senate bill in 2014 proposed to extend the program to 2050. Although that bill was not adopted, similar legislation may be proposed in the future.

In 2015, the California cap-and-trade program began to cover emissions from the sale of propane and liquid transportation fuels for use in the state. Producers or marketers of propane and refiners of liquid transportation fuels will be responsible for retiring allowances equivalent to the metric tons of carbon dioxide estimated to be produced

from the combustion of the propane and transportation fuels they market for use in California. Under AB 32, CARB has also imposed a “low carbon fuel” standard, which requires refiners to reduce the carbon content of transportation fuels they market in California by 10% by 2020. In January 2015, California’s Governor proposed goals for 2030 to derive 50% of California’s electricity from renewable sources, to reduce petroleum use in cars and trucks by 50% from current levels, and to double the energy efficiency of buildings in the state, and legislation has been proposed to implement these goals. These programs and policies, as well as federal and California subsidies and tax incentives for the development and construction of alternative energy-fueled power generation and transportation, may reduce demand for our products and services or require further controls on, or modifications to, our operations.

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

Regulation of Transportation and Sale of Our Products

Our sales prices of oil, NGLs and natural gas are set by the market and are not presently regulated. Interstate transportation rates for oil, NGLs and other products are regulated by the Federal Energy Regulatory Commission (“FERC”). Our sales price for these products is affected by transportation costs. The FERC has established an indexing system for such transportation, which allows pipelines to take an annual inflation-based rate increase. We are not able to predict what effect, if any, these regulations will have on us, but, other factors being equal, the regulations may, over time, tend to increase transportation costs, which may affect our margins for oil and NGLs. Federal law currently restricts the export of domestically produced oil, with certain exceptions, such as for a limited quantity of California heavy crude oil. If these restrictions were lifted we may be able to sell our oil production in additional markets, which may increase prices we realize.

Market manipulation and market transparency regulations

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

Natural gas gathering regulations

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

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

Regulation of power sales and transmission

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

Employees

As of December 31, 2014, we had approximately 1,990 employees. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. Approximately 80 of our employees are represented by labor unions. We have not experienced any strikes or work stoppages by our employees in the past 35 years or longer. We also utilize the services of independent contractors to perform drilling, well work, operations, construction and other services, including construction contractors whose workforce is often represented by labor unions.

Effective January 1, 2015, we adopted the California Resources Corporation 2014 Employee Stock Purchase Plan (the "ESPP"). The ESPP will provide 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. As of January 1, 2015, about 45% of our employees have elected to participate in the plan.

Legal Proceedings

No new reportable matters have arisen since the filing of our annual report on Form 10-K.

MANAGEMENT

Executive Officers

The current term of employment of each of our executive officers will expire at the May 7, 2015 organizational meeting of the Board of Directors or when a successor is selected. The following table sets forth our executive officers:

Name	Position(s) held	Age at February 26, 2015
William E. Albrecht	Executive Chairman	63
Todd A. Stevens	President and Chief Executive Officer	48
Marshall D. Smith	Senior Executive Vice President and Chief Financial Officer	55
Robert A. Barnes	Executive Vice President—Northern Operations	58
Frank E. Komin	Executive Vice President—Southern Operations	60
Shawn M. Kerns	Executive Vice President—Corporate Development	44
Roy Pineci	Executive Vice President—Finance	52
Michael L. Preston	Executive Vice President, General Counsel and Corporate Secretary	50
Charles F. Weiss	Executive Vice President—Public Affairs	51
Darren Williams	Executive Vice President—Exploration	43

William E. Albrecht was appointed as Executive Chairman of CRC in July 2014. Mr. Albrecht served as Vice President of Occidental from May 2008 to July 2014 and as President, Oxy Oil & Gas, Americas from January 2012 to July 2014. Mr. Albrecht also served as President—Oxy Oil & Gas, USA from April 2008 to January 2012. During his tenure with Occidental, Mr. Albrecht had managerial oversight over its upstream assets. Mr. Albrecht has more than 35 years of experience in the domestic oil and gas industry, having previously served as an executive officer for

domestic energy producer EOG Resources, and as a petroleum engineer for Tenneco Oil Company. Mr. Albrecht holds a Master of Science degree from the University of Southern California and a Bachelor of Science degree from the United States Military Academy. Mr. Albrecht's extensive managerial and operational experience in the upstream domestic energy business and his specific knowledge of our assets and proactive engagement with regulatory agencies, communities, and other stakeholders make him a valuable member of our Board of Directors.

Todd A. Stevens was appointed President, Chief Executive Officer and director of CRC in July 2014. Mr. Stevens served as Vice President—Corporate Development of Occidental Petroleum Corporation from August 2012 to July 2014, as Vice President—California Operations, Oxy Oil & Gas from April 2008 to September 2012, and as Vice President—Acquisitions and Corporate Finance of Occidental from October 2004 to August 2012. Mr. Stevens holds a Master of Business Administration degree from the University of Southern California and a Bachelor of Science degree from the United States Military Academy. Our Board of Directors will benefit from Mr. Stevens' deep knowledge of the oil and gas industry, his expertise in strategically evaluating and valuing oil and gas assets, and his significant managerial experience as an executive at Occidental, including his extensive experience in allocating capital, managing Occidental's and our assets and dealing with California's regulatory environment, agencies and political landscape.

Marshall D. "Mark" Smith was appointed Senior Executive Vice President and Chief Financial Officer of CRC in July 2014. Mr. Smith served as Senior Vice President of Ultra Petroleum Corp. from January 2011 to July 2014 and served as its Chief Financial Officer from July 2005 to July 2014. Mr. Smith's 32 years of experience in the energy industry spans operations, strategic planning, corporate finance and business development. He began his career as a petroleum engineer working at both major and independent oil companies, later focusing on mergers, acquisitions and corporate finance advisory assignments. Mr. Smith served as Vice President of Upstream Business

Development at Constellation Energy from 2004 to 2005. Mr. Smith was the Vice President of Business Development at J.M. Huber Energy from 2002 to 2004, and Chief Financial Officer of Gulf Liquids, Inc. from 2001 to 2002. Mr. Smith holds a Masters of Business Administration degree with highest honors from Oklahoma City University and a Bachelors of Science degree from the University of Oklahoma.

Robert A. Barnes was appointed Executive Vice President—Northern Operations of CRC in July 2014. Mr. Barnes served as President and General Manager of Occidental of Elk Hills from December 2012 to July 2014. He served as Operations Manager for Oxy Permian CO₂ from May 2011 to November 2012, as Deputy General Manager and Senior Vice President, Operations, of Occidental Argentina from June 2010 to April 2011, and as Vice President, Operations, of Occidental Argentina from August 2007 to June 2010. Mr. Barnes also held Production Operations Manager and Operations Team Leader roles at Occidental of Elk Hills from 1998 to 2007, and worked as Production Superintendent in the Hugoton and Virginia Coalbed Methane Operations and held various roles in Operations and Drilling Engineering throughout the Rocky Mountains, California and Mid-Continent regions since joining Occidental in 1978. Mr. Barnes has over 36 years of oil and gas industry experience and holds a Bachelor of Business Administration degree from New Mexico State University.

Frank E. Komin was appointed Executive Vice President—Southern Operations of CRC in July 2014. Mr. Komin served as President and General Manager of OXY Long Beach from February 2001 to July 2014, and served as President and General Manager of Oxy THUMS from February 2001 to December 2009. During his tenure at OXY Long Beach, Mr. Komin oversaw all aspects of Long Beach operations and the development of the Wilmington field. Mr. Komin has more than 36 years of experience in the domestic oil and gas industry. Before joining Oxy THUMS in 2000 as Manager, Production & Development, Mr. Komin worked for 22 years at ARCO as Reservoir Engineering Manager and Operations Superintendent, Kuparuk, Alaska from 1993 to 1997, as Asset Manager in Midland Permian Basin, from 1988 to 1993, District Coordinator in Dallas, Texas, from 1987 to 1988, and in various engineering and engineering leadership roles from 1978 to 1987. Mr. Komin holds a Bachelor of Science degree from the University of Kansas.

Shawn M. Kerns was appointed Executive Vice President—Corporate Development of CRC in July 2014. Mr. Kerns served as President and General Manager of Vintage Production California from December 2012 to July 2014. He served as General Manager for Occidental of Elk Hills from June 2010 to December 2012, as Asset Development Manager for Occidental of Elk Hills from October 2008 to April 2010, and as Vice President, Operations, of Occidental Petroleum of Qatar Ltd. from July 2007 to October 2008. Mr. Kerns also held various management roles for Occidental of Qatar Inc., Occidental of Elk Hills and OXY USA Inc. from 1992 to 2007. Mr. Kerns has over 22 years of oil and gas industry experience and holds a Bachelor of Science in Electrical Engineering degree from the University of Oklahoma and studied Business and Managerial Economics at University of California, Los Angeles.

Roy Pineci was appointed Executive Vice President—Finance of CRC in July 2014. Mr. Pineci served as Vice President and Controller of Occidental Petroleum Corporation from November 2008 to July 2014, and served as Senior Vice President, Occidental Oil and Gas from November 2007 to November 2008. He served as Vice President, Internal Audit for Occidental Petroleum Corporation from June 2005 to October 2007. Prior to joining Occidental, Mr. Pineci was a Partner at KPMG LLP in Los Angeles where he worked from 2002 through May 2005 and worked at Andersen LLP in Los Angeles from 1985 to 2002 where he was a partner from 1997. Mr. Pineci holds a Bachelor of Arts in Business Administration/Accounting from Coe College and is a member of the American Institute of Certified Public Accountants and the California Society of CPAs.

Michael L. Preston was appointed Executive Vice President, General Counsel and Corporate Secretary of CRC in July 2014. Mr. Preston served as Vice President and General Counsel of Occidental Oil and Gas from June 2001 to July 2014. He had previously served in successive roles as Senior Counsel, Managing Counsel and Vice President and General Counsel—North America after joining Occidental Oil and Gas in February 1997. Prior to joining Occidental, Mr. Preston was a Corporate Associate for Sullivan & Cromwell from October 1990 to February 1997. Mr. Preston holds a Bachelor of Arts from the University of California, Los Angeles and a Juris Doctorate from Loyola Marymount University.

Charles F. Weiss was appointed Executive Vice President—Public Affairs of CRC in July 2014. Mr. Weiss served as Vice President, Health, Environment and Safety of Occidental Petroleum Corporation from October 2007 to July 2014, as Vice President and General Counsel, OXY Inc. from October 2001 to October 2007, and as Chief Counsel, Oxy Litigation Group from July 2000 to September 2001. He served as Senior Counsel of Occidental Petroleum Corporation from May 1996 to July 2000. Prior to joining Occidental, Mr. Weiss was a Partner at Latham & Watkins LLP from January to May 1996 and started his legal career there as an Associate in September 1988. Mr. Weiss received a Bachelor of Science in Engineering degree in Chemical Engineering from Princeton University and a Juris Doctorate from the University of Michigan.

Darren Williams was appointed Executive Vice President—Exploration in September 2014. Mr. Williams has 20 years of experience in the oil and gas industry, working 17 of those years for Marathon Oil in London, Houston and Oklahoma City. Mr. Williams has broad experience and a proven track record in both conventional and unconventional exploration programs. Mr. Williams served as Africa Exploration Manager and President of Marathon Upstream Gabon Limited from May 2013 to September 2014. From September 2010 to May 2013 he served as Oklahoma Subsurface Manager where he managed the Woodford shale development program and established Marathon’s Oklahoma Resource Basin growth strategy. From 2008 to 2010, Mr. Williams served as Gulf of Mexico Exploration and Appraisal Manager overseeing participation in the Gunflint and Shenandoah discoveries and from 2004 to 2008 he managed teams responsible for discovery of the Droshky field and rebuilding Marathon’s deepwater Gulf of Mexico inventory. From 1997 to 2004, Mr. Williams held various roles exploring assets in Europe, Africa & the Gulf of Mexico. Mr. Williams holds a Master of Science degree from Royal Holloway, University of London, UK, and a Bachelor of Science degree from the University of Leicester, UK.

Board of Directors

Our Board of Directors consists of nine members, seven of which our Board has determined satisfy the independence standards established by the Sarbanes-Oxley Act of 2002 and the applicable rules of the SEC and the NYSE. In addition, our Board increased its size to ten members and appointed Catherine A. Kehr as a director, in each case effective March 15, 2015. Our Board determined that Ms. Kehr also satisfies the independence requirements. Our Board of Directors is temporarily divided into three classes. One of the three classes is elected each year on a rotating basis to succeed the directors of the subject class whose terms are expiring. In this manner, as of the 2015 Annual Meeting, the term of the directors in Classes I, II and III of the board expire in 2015, 2016 and 2017, respectively. However, commencing with the election of the directors at the 2018 Annual Meeting, the Board of Directors will cease to be classified, and the directors elected at the 2018 Annual Meeting (and each annual meeting thereafter) will be elected for a one year term.

Set forth below is biographical information regarding each of our directors as well as the specific experience, qualifications, attributes and skills that led to the conclusion that such individual should serve as director. There are no family relationships between any of our directors and executive officers. In addition, there are no arrangements or understandings between any of our executive officers or directors and any other person pursuant to which any person was selected as a director or an executive officer, respectively.

Name	Age
William E. Albrecht	63
Justin A. Gannon	65
Ronald L. Havner	57
Catherine A. Kehr ⁽¹⁾	52
Harold M. Korell	70
Richard W. Moncrief	72
Avedick B. Poladian	63
Robert V. Sinnott	65
Timothy J. Sloan	54
Todd A. Stevens	48

(1) Appointed effective March 15, 2015.

Justin A. Gannon—Immediately following the Spin-off, Mr. Gannon was appointed to the Board of Directors of CRC. Since September 2013, Mr. Gannon has acted as an independent consultant and private investor. From February 2003 through August 2013, Mr. Gannon served in various roles at Grant Thornton LLP, an independent audit, tax and advisory firm, including as National Leader of Merger and Acquisition Development from June 2011 through August 2013, Central Region Managing Partner from October 2009 through June 2011, Office Managing Partner in Houston, Texas from May 2007 through June 2011 and Office Managing Partner in Kansas City, Missouri from August 2004 to May 2007. From 1971 through 2002, Mr. Gannon worked at Arthur Andersen LLP, including as an Audit Partner for 21 years. Mr. Gannon is also a Director, Chairman of the Audit Committee and Member of the Conflicts Committee of the general partner of CrossAmerica Partners LP, a publicly traded master limited partnership engaged in motor fuels distribution. He is a former chairman of the Board of Directors of American Red Cross chapters in the Tulsa, Oklahoma and San Antonio, Texas areas. Mr. Gannon received a Bachelor of Science degree in Accounting from Loyola Marymount University and is a Certified Public Accountant licensed in Texas and California. Mr. Gannon's more than four decades in financial accounting practice and his private investment experience give him deep insight into financial analysis and management. His financial acumen provides Mr. Gannon valuable expertise to provide the CRC Board of Directors with guidance on its fiscal management and strategic direction.

Ronald L. Havner, Jr.—Immediately following the Spin-off, Mr. Havner was appointed to the Board of Directors of CRC. Mr. Havner is the Chairman of the Board, President and Chief Executive Officer of Public Storage, a developer, owner, and operator of self-storage facilities. He was elected Vice Chairman and Chief Executive Officer of Public Storage in 2002 and was elected Chairman of the Board in August 2011. He joined Public Storage in 1986. Mr. Havner has been Chairman of the Board of Public Storage's affiliate, PS Business Parks, Inc. since 1996 and served as its Chief Executive Officer until 2003. He currently serves on the board of Avalon Bay, a publicly traded real estate investment company. He is the 2014 Chairman of the Board of Governors of the National Association of Real Estate Investment Trusts, Inc. Mr. Havner holds a Bachelor of Arts degree from the University of California in Los Angeles. Mr. Havner's experience as Chief Executive Officer of a public, California-headquartered business with locations across the United States and Europe gives him insight into business generally and California in particular that will benefit CRC. His nearly three decades of experience growing a business gives him valuable perspectives that will help CRC implement its business plans.

Catherine A. Kehr—Ms. Kehr was appointed to the Board of Directors CRC effective as of March 15, 2015. She has been a member of the board of directors of Southwestern Energy Company since 2011 where she serves as Presiding Director, Chair of the Nominating and Governance Committee and a member of the Audit Committee. She retired in 2006 as a Senior Vice President and Director of Capital Research Company, a division of The Capital Group Companies, one of the world's largest investment management organizations and manager of the American Funds. From 1997 to 2006, she was an investment analyst and fund manager with responsibility for global energy equities and, from 1992 to 1997, she had responsibility for global energy high yield debt for The Capital Group Companies. Prior to her tenure with The Capital Group Companies, she held various managerial positions at Atlantic Richfield Company and Payden & Rygel. In 2001, the Reuters Survey ranked Ms. Kehr among the top 10 individual U.S. fund managers. Ms. Kehr received a Bachelor of Arts from Yale University and an MBA from The Wharton School of the University of Pennsylvania, and she holds a Chartered Financial Analyst designation. Ms. Kehr's experience and insights as an investor and a board member in the oil and gas industry will be of great value to CRC.

Harold M. Korell (Lead Independent Director)—Immediately following the Spin-off, Mr. Korell was appointed to the Board of Directors of CRC. From May 2002 through May 2014, Mr. Korell served as the Chairman of the Board of Southwestern Energy Company, an independent energy company engaged in natural gas and oil exploration, development and production. From May 2009 through March 2010, he served as Southwestern's Executive Chairman and, from January 1999 through May 2009, as its Chief Executive Officer. From 1997 through May 2009, Mr. Korell served in various other roles at Southwestern, including President and Executive Vice President and Chief Operating Officer. Prior to his tenure at Southwestern, Mr. Korell was Senior Vice President—Operations of American Exploration Company, Executive Vice President of McCormick Resources, held various technical and managerial positions during his 17 years with Tenneco Oil Company, including Vice President of Production, and held various positions with Mobil Corporation. He is a member of the Society of Petroleum

Engineers and, through 2010, served as a Board Member for the Independent Petroleum Association of America and the American Exploration & Production Council and as a Board Member and Executive Committee Member for America's Natural Gas Alliance. He also serves on the Board of Governors at the Colorado School of Mines and the Board of Trustees at the Baylor College of Medicine. Mr. Korell holds a degree in Chemical and Petroleum Refining Engineering from the Colorado School of Mines. Mr. Korell's experience over four decades in the oil and gas industry gives him a deep understanding of the upstream oil and gas business as well as the midstream and public utility businesses.

Richard W. Moncrief—Immediately following the Spin-off, Mr. Moncrief was appointed to the Board of Directors of CRC. Mr. Moncrief has been a principal in Moncrief Oil International, Inc., an oil and gas exploration and production company with headquarters in Fort Worth, Texas, since founding the company in 1970. He currently serves as its Chief Executive Officer. Moncrief Oil participates in U.S. and international oil and gas exploration and production. Mr. Moncrief also serves on the boards of trustees for the Amon Carter Museum and the University of Texas Development Board. He holds a Bachelor of Science degree in petroleum engineering from the University of Texas. Mr. Moncrief's extensive

experience in the upstream oil and gas industry will bring an in-depth understanding of key industry issues to the CRC Board of Directors. His leadership experience at Moncrief Oil provides him with strategic and management insights from which CRC can benefit.

Ayedick B. Poladian—Mr. Poladian was appointed to the Board of Directors of CRC in September 2014. Since 2006, Mr. Poladian has served as Executive Vice President and Chief Operating Officer of Lowe Enterprises, Inc., a diversified national real estate company active in commercial, residential and hospitality property investment, management and development. Mr. Poladian previously served as Executive Vice President, Chief Financial Officer and Chief Administrative Officer for Lowe from 2003 to 2006. Mr. Poladian was with Arthur Andersen LLP from 1974 to 2002, most recently as a Partner, and is a Certified Public Accountant (inactive). He is a past member of the Young Presidents Organization, the Chief Executive Organization, the California Society of CPAs and the American Institute of CPAs. Mr. Poladian is a director of the YMCA of Metropolitan Los Angeles, a member of the Board of Councilors of the University of Southern California Price School of Public Policy, a member of the Board of Advisors of the Ronald Reagan UCLA Medical Center, and a former Trustee of Loyola Marymount University. He serves as a director and on the Audit Committees of two funds managed by Western Asset Management Funds. He is also a member of the Board of Trustees of Public Storage where he is the Chair of the Audit Committee and the Chair of the Nominating and Corporate Governance Committee. Mr. Poladian also serves as a director of Occidental Petroleum Corporation where he is a member of the Executive Compensation Committee and the Finance and Risk Management Committee, and chair of the Audit Committee. He previously served as a director of California Pizza Kitchen. His service in a senior management position at one of the world’s largest accounting firms, combined with his experience as Chief Operating Officer and Chief Financial Officer of a diversified real estate company, gives Mr. Poladian deep knowledge of key business issues, including personnel and asset utilization, in addition to all aspects of fiscal management. Through his work on the boards of various entities, Mr. Poladian has garnered valuable insight into our business and corporate governance generally.

Robert V. Sinnott—Immediately following the Spin-off, Mr. Sinnott was appointed to the Board of Directors of CRC. Mr. Sinnott is President, Chief Executive Officer and Chief Investment Officer of Kayne Anderson Capital Advisors, L.P., an investment management firm. He also served as a Managing Director there from 1992 to 1996 and as its Senior Managing Director from 1996 until assuming his CEO role in 2010. He is also President of Kayne Anderson Investment Management, Inc., the general partner of Kayne Anderson Capital Advisors, L.P. Mr. Sinnott served as a director of Kayne Anderson Energy Development Company from 2006 through 2013. He was Vice President and Senior Securities Officer of the Investment Banking Division of Citibank from 1986 to 1992 and previously held positions with United Energy Resources, a pipeline company and Bank of America in its oil and gas finance department. Mr. Sinnott has served on the board of the general partners of Plains All American Pipeline, L.P. and its public general partner, Plains GP Holdings, L.P., since 1998 and 2013, respectively. Additionally, he is a director of the Kayne Anderson Capital Advisors Foundation and a member of the Board of Visitors of the UCLA Anderson School of Management. Mr. Sinnott received a Bachelor of Arts degree from the University of Virginia and a Masters of Business Administration from Harvard University. As President of a California-based investment company investing in energy and other areas, Mr. Sinnott brings extensive insight into the oil and gas and financial

industries to the CRC Board of Directors. His responsibility for analyzing industry players and managing a multi-billion dollar investment enterprise allow him to provide insight on a broad variety of matters that will affect CRC.

Timothy J. Sloan — Immediately following the Spin-off, Mr. Sloan was appointed to the Board of Directors of CRC. Mr. Sloan is Senior Executive Vice President Wholesale Banking for Wells Fargo & Company and has served in this position since May 2014. He also serves on the Operating and Management Committees of Wells Fargo & Company. Mr. Sloan was Senior Executive Vice President and Chief Financial Officer of Wells from 2011 to May 2014. He was Senior Executive Vice President and Chief Administrative Officer from 2010 to 2011 and Executive Vice President (Commercial Banking, Real Estate and Specialized Financial Services) of Wells Fargo Bank, N.A. from 2006 to 2010. Mr. Sloan serves on the Board of Overseers of the Huntington Library, and is a member of the University of Michigan’s Ross School of Business Advisory Board. He is a trustee of Ohio Wesleyan University and the City of Hope. He earned his B.A. in economics and history and his M.B.A. in finance and accounting, both from the University of Michigan in Ann Arbor. His deep and broad experience analyzing businesses and his senior managerial roles, including as CFO, at one of the nation’s largest banks provides CRC with valuable perspectives and advice.

Board Committees

Our Board of Directors has four separately designated standing committees. The membership and purpose of each of the committees are described below. Each of the committees operates under a written charter adopted by the board. The Board of Directors and each committee has the power to hire independent legal, financial or other experts and advisers as it may deem necessary, without consulting or obtaining the approval of any of our officers in advance.

Audit Committee

Our Audit Committee is composed entirely of independent directors. The committee meets separately with representatives of our independent auditors, our internal audit personnel and representatives of senior management in performing its functions. The Audit Committee approves the appointment of the independent registered public accounting firm and reviews the general scope of audit coverage, matters relating to internal controls systems and other matters related to accounting and reporting functions. The Audit Committee also considers the qualifications and

independence of the independent reserves engineering firm, and approves the selection and appointment of such firm. The Board of Directors determined that all of the members of the Audit Committee are financially literate and have accounting or related financial management expertise, each as required by the applicable NYSE listing standards. The Board of Directors also determined that Mr. Gannon qualifies as an audit committee financial expert under the applicable rules of the Exchange Act.

Compensation Committee

Our Compensation Committee is composed entirely of independent directors. The committee is responsible for (i) determining compensation for our Chief Executive Officer and other executive officers, (ii) overseeing and approving compensation and employee benefit policies and (iii) reviewing and discussing with our management the Compensation Discussion and Analysis and related disclosure included in our annual proxy statement. The Board of Directors has formed a subcommittee of the Compensation Committee to serve as the "Committee" for purposes of administering the CRC LTIP, as defined below, and taking such other actions as the subcommittee determines are advisable for purposes of qualification for certain exemptions set forth in Section 16 of the Securities Exchange Act of 1934, as amended (including Rule 16b-3 thereunder) and Section 162(m) of the Internal Revenue Code of 1986, as amended. Messrs. Korell and Gannon are the members of the subcommittee and, as of March 15, 2015, Ms Kehr will be a member.

Nominating and Governance Committee

The Nominating and Governance Committee is composed entirely of independent directors. The committee makes proposals to the Board of Directors for candidates to be nominated by the Board of Directors to fill vacancies or for new directorship positions, if any, which may be created from time to time. The Nominating and Governance

Committee develops and recommends a set of corporate governance guidelines to our Board of Directors and oversees evaluation of our board and management. The Nominating and Governance Committee leads the Board of Directors in the annual performance review of our management, including our Chief Executive Officer. The Nominating and Governance Committee meets periodically on succession planning. Our Corporate Governance Guidelines state that our Chief Executive Officer should at all times make available his or her recommendations and evaluations of potential successors, along with a review of any development plans recommended for such individuals.

Health, Safety and Environmental Committee

Our Health, Safety and Environmental Committee is composed entirely of independent directors. The committee reviews and discusses the status of health, safety and environmental objectives, issues, laws and regulations with management. It also reviews our programs to ensure compliance with applicable laws and regulations, conservation of natural resources and related community engagement and periodically reports to the Board of Directors on matters affecting us.

Director Independence

To qualify as "independent" under the NYSE listing standards, the Board of Directors must affirmatively determine that the director has no material relationship with us (either directly or as a partner, stockholder or officer of an organization that has a relationship with us) that would interfere with his or her exercise of independent judgment in carrying out his or her responsibilities as a director. The NYSE independent director criteria include that the director not be our employee and not have engaged in various types of business dealings with us.

The Board of Directors has reviewed all direct or indirect business relationships between each director (including his or her immediate family) and us, including those relationships described under "Certain Relationships and Related Party Transactions" as well as each Director's relationships with charitable organizations, to assess director independence as defined in the listing standards of the NYSE. Based on this evaluation, the Board of Directors has determined that Messrs. Gannon, Havner, Korell, Moncrief, Poladian, Sloan and Sinnott and Ms. Kehr are independent directors as that term is defined in the listing standards of the NYSE. Neither Mr. Albrecht, the Executive Chairman of the Board, nor Mr. Stevens, the President and Chief Executive Officer, is considered by the Board of Directors to be an independent director because of his employment with us.

Compensation Committee Interlocks and Insider Participation

No member of our Compensation Committee is now, or at any time since the beginning of 2014 has been, employed by or served as an officer of us or any of our subsidiaries or had any relationships requiring disclosure with us or any of our subsidiaries. None of our executive officers is now, or at any time has been, since the beginning of 2014, a member of the compensation committee or board of directors of another entity one of whose executive officers has been a member of our Board of Directors or Compensation Committee.

EXECUTIVE COMPENSATION

For purposes of the Compensation Discussion and Analysis, we refer to Messrs. Stevens, Smith, Albrecht, Pineci and Williams collectively as our “named executive officers.”

Compensation Program

The CRC Compensation Committee was formed in December of 2014 following our Spin-off from Occidental.

In order to avoid disruptions to our executive compensation program and ensure an orderly transition of our new management team, our initial executive compensation program was approved by Occidental’s Executive Compensation Committee (“Occidental’s Compensation Committee”) and was in effect at the time of our Spin-off. As such, all executive compensation decisions for our named executive officers prior to and in conjunction with the Spin-off were made by Occidental. Pay Governance LLC, Occidental’s independent compensation consultant, assisted in the design and implementation of our initial compensation program.

In early 2014, Pay Governance LLC assisted Occidental’s Compensation Committee in developing an initial compensation peer group for purposes of conducting market analyses and to determine the level and form of executive and broad-based compensation immediately following the Spin-off.

Executive compensation decisions following the Spin-off have been made by the CRC Compensation Committee. In January 2015, the CRC Compensation Committee engaged Meridian Compensation Partners (“Meridian”) as its independent compensation consultant to assist with the review and development of the 2015 compensation program. In February 2015, the CRC Compensation Committee approved a new annual incentive program as described in "2015 Annual Incentive Design" below.

Compensation Philosophy

The following core principles form the foundation of the initial compensation program for our executives, including the named executive officers.

- First*, compensation programs should motivate our executives to take actions that are aligned with our short- and long-term strategic objectives, and appropriately balance risk versus potential reward.
- Second*, a high percentage of senior executive’s pay should be based on performance to ensure the highest level of accountability to stockholders.
- Third*, performance pay should offer an opportunity for above average compensation when our performance exceeds our goals balanced by the risk of below average compensation when it does not.
- Fourth*, a focus on the long-term performance of the Company, thereby more closely aligning their interests with those of our stockholders.

Compensation Objectives

Our initial executive compensation program was designed to provide competitive compensation levels generally targeted to market median, with flexibility to adjust these levels based on individual factors such as experience, performance, and internal equity. The following matters were important to the development of our compensation program:

- Market practices.
 - The need for a smooth transition and retention of talent from Occidental to us.
 - The need to attract executive talent from outside of Occidental.
-
- The need to provide CRC with an initial program immediately following the Spin-off, recognizing that our Board of Directors (or a committee thereof) and management will be responsible for program design following the Spin-off.

The descriptions below reflect our initial compensation program for our named executive officers following the Spin-off, which we inherited from Occidental. During 2015, the CRC Compensation Committee will review the compensation program and make adjustments as it deems appropriate to support our long-term strategic objectives.

Peer Companies

Since we considered market practices in designing our initial compensation program, Pay Governance LLC, in its role for the Occidental Compensation Committee, helped to develop a peer group of companies on which to base market practice. This market data was considered in the design of our initial compensation program. Our compensation peer group was developed using a multi-step screening process based on the following criteria:

- Industry—Companies in the Global Industry Classification Standard sub-industry of oil and gas exploration and production.
- Scope—Companies in the range of 25% - 400% of our expected market capitalization and 40%- 250% of our expected revenue.
- Geography—U.S.-listed companies focused on U.S. exploration and production.

Based on these factors, the following compensation peer group was selected by the Occidental Compensation Committee, which includes companies generally similar in operations and scope to CRC, as well as companies that may have some operational or scope differences to CRC, but are in the same industry and provide a more robust peer group:

Peer Companies

Apache Corporation	Cabot Oil and Gas Corporation
Chesapeake Energy Corporation	Cimarex Energy Co.
Concho Resources Inc.	Continental Resources, Inc.
Denbury Resources Inc.	Devon Energy Corporation
EOG Resources, Inc.	Marathon Oil Corporation
Newfield Exploration Company	Noble Energy, Inc.
Pioneer Natural Resources Company	QEP Resources, Inc.
Range Resources Corporation	Southwestern Energy Company
Whiting Petroleum Corporation	WPX Energy, Inc.

Our initial compensation program encompasses the concept that overall executive compensation should include elements that provide an appropriate level of fixed compensation necessary to attract and retain employees; annual incentive compensation that links annual cash compensation to the achievement of key short-term performance goals; and long-term compensation linked to goals that contribute to long-term growth of stockholder value.

The following tables describe the components of our initial compensation program and the objectives of each component.

Annual Compensation

Description	Objectives
Base Salary	• Annual cash compensation • Provide an appropriate level of fixed compensation necessary to attract and retain employees • Recognize and reward skills, competencies, experience, leadership and individual contribution
Annual Incentive Plan	• Annual cash incentive based on corporate and individual performance • Link annual cash compensation to individual performance and attainment of key short-term performance results across all executive officers as measured primarily by annual operating performance

Long-Term Compensation

Description	Objectives
Stock Options	• Provides opportunity to purchase stock at a fixed price over a seven-year period. Results in value only if stock price increases. • Link realized compensation over long-term to appreciation in stock price • Facilitate retention of employees • Build executive stock ownership • Align interests of management with those of stockholders
Performance Based Restricted Stock Awards	• Long-term incentive program with award payouts tied to achievement of financial goals. • Link compensation to achieved performance against key financial goals over a three to seven year period, as well as changes in share price. • Facilitate retention of employees • Align interests of management with those of stockholders

Salary—The salaries for our named executive officers were established by Occidental based on peer group market data, as well as individual factors including experience, internal pay equity, and the need to attract and retain exceptional executives from inside and outside of Occidental.

Annual Incentive—The annual incentive component of our initial compensation program was designed to promote the achievement of financial, operating and strategic goals that are aligned with creation of shareholder value, including specific activities related to the Spin-off. Under the annual incentive plan, each named executive officer had a target annual incentive opportunity expressed as a percentage of salary. The bonus targets were based

on the position and scope of responsibilities of each named executive officer. Award opportunities ranged from 0% to 200% of target to be paid in cash.

Because the Spin-off was announced by Occidental in February 2014 and completed on November 30, 2014, our named executive officers spent the majority of 2014 focused on establishing us as an independent public company, while also managing our California operations to produce strong results in the deteriorating oil price environment in the second half of the year. Thus, our named executive officers' focus in 2014 was different than that of other Occidental executives. The CRC Compensation Committee considered this and the timing of the Spin-off and determined that the 2014 annual incentive for the named executive officers should recognize both the results related to the execution of the Spin-off and the results of the California business in 2014, independent of Occidental's 2014 results.

Specifically, the CRC Compensation Committee considered the following factors in its determination of the 2014 annual incentive payouts for the named executive officers (See Annex B for a reconciliation of GAAP and non-GAAP financial measures with respect to core income, EBITDAX, reserves replacement ratio, and finding and development costs):

Financial and Operating Results

- Delivered strong full year results in spite of a sharp decline in oil prices in the last half of 2014 (average price of Brent declined from \$108.76 per barrel in 2014 to \$99.51 per barrel in 2013 (8.5% decline), realized prices were \$92.30 per barrel in 2014 versus \$104.16 per barrel in 2013 and \$68.54 per barrel in the fourth quarter 2014 versus \$99.32 per barrel in the fourth quarter 2013):
 - ? Core income of \$650 million in 2014 versus \$869 million in 2013
 - ? EBITDAX of \$2.5 billion versus \$2.7 billion for 2013
 - ? Cash flow from operations of \$2.4 billion versus \$2.5 billion in 2013
- Delivered total average 2014 production of 159 MBoe/d versus 154 MBoe/d in 2013 (3% increase)
- Increased average oil production to 99 MBoe/d in 2014 from 90 MBoe/d in 2013 (10% increase)
- Achieved record quarterly total average production of 165 MBoe/d in the fourth quarter 2014 (5% over the fourth quarter 2013, 3% over the third quarter 2014)
- Achieved record quarterly average oil production of 105 MBoe/d in the fourth quarter 2014 (12% over the fourth quarter 2013, 5% over the third quarter 2014)
- Delivered organic reserve replacement ratio from our capital program of 203%
- Increased 2014 year-end reserves to 768 MMBoe versus 744 MMBoe in 2013
- Reduced finding and development costs to \$17.68 per Boe in 2014 versus \$19.16 per Boe in 2013
- Quickly responded to the deteriorating oil price environment:
 - ? Starting an aggressive cost containment program toward the end of 2014, contributing to a decline in production costs to \$16.07 per Boe in the fourth quarter of 2014 versus \$17.74 per Boe in the third quarter of 2014
 - ? Reducing our drilling rig count from 27 in November 2014 to six at year end 2014
 - ? Implementing a hedging program covering almost all of our oil production for the first six months of 2015 to protect against our down-side risk and preserve our ability to execute our capital program

Health, Safety and Environment

- Improved performance, as indicated by a combined employee and contractor injury and illness incidence rate of 0.46 in 2014 versus 0.53 in 2013
- Enhanced our reputation in California by supplying a record two billion gallons of water from our steamflood operations to California's agriculture industry and, as a result, we provided more water for irrigation than the amount of fresh water we purchased for our statewide operations.

Execution of Spin-off

- Recruited a highly qualified group of outside directors
- Recruited a senior management team both from within Occidental and with external hires in key positions
- Established independent financial systems and functions, information technology infrastructure and support groups, trading and marketing operations and supply chain groups

- Placed \$6.0 billion of long-term debt at favorable interest rates
- Established a \$2.0 billion unsecured revolving credit facility
- Met with over 180 investors prior to Spin-off
- Successfully executed the Spin-off despite a dramatic downturn in commodity prices

Based on an overall evaluation of these factors, the Compensation Committee determined that payout of the 2014 annual incentives in the range of the target incentive amounts with modest upward adjustments for significant individual contributions, as shown in the table below, would appropriately reward the named executive officers for their 2014 performance. The CRC Compensation Committee believes that these payouts appropriately reflect the outstanding operational performance, HSE accomplishments, and successful Spin-off while also recognizing the adverse impact of the oil price decline on financial results and shareholder value.

Named Executive Officer	2014 Annual Incentive Target as Percent of Salary	2014 Annual Incentive Payout as Percent of Target	Resulting Cash Payout
Todd A. Stevens	100%	105%	\$865,000
Marshall D. Smith	100%	113%	\$675,000
William E. Albrecht	150%	100%	\$750,000
Roy Pineci	75%	101%	\$310,000
Daren Williams	90%	100%	\$405,000

Long-Term Incentives—Our initial compensation program provides the majority of each named executive officer’s compensation package through long-term incentives. The long-term incentive portion of the initial compensation program used two types of awards:

- Stock Options**—Stock options represent 50%-60% of the total long-term incentive award value for our named executive officers. These awards are intended to incentivize executive behaviors that drive value creation that leads to long-term growth of stockholder value. The stock options will vest in equal installments over three years from the grant date and will have a seven-year exercise term. To provide additional incentive to named executive officers to achieve meaningful stock price appreciation, initial awards of stock options to named executive officers in connection with the Spin-off were granted with an exercise price that was 10% above the fair market value of our common stock at the time of the grant.
- Performance-Based Restricted Stock Awards**—Restricted stock represents 40%-50% of the total long-term incentive award value for our named executive officers. These awards are intended primarily to enhance retention and development of ownership in the new organization and will vest, subject to attainment of a minimum level of earnings before interest, taxes, depreciation and amortization (“EBITDA”) as an established performance goal, as early as the end of three years from the grant date if the performance criteria are met, or as late as the end of seven years from the grant date. If the performance goal is not attained by the end of seven years, the award will forfeit in its entirety.

The following table summarizes key features of the long-term incentive components of the initial compensation program for our named executive officers.

	Performance-Based Restricted Stock Awards	Stock Options
Vesting Period	Later of 3 years or attainment of performance goals.	1/3 of grant at end of each of first, second and third years.
Performance Period	3-7 Years	1-7 Years
Form of Payout	Stock	Stock
Performance Basis	Cumulative EBITDA of at least \$250 million times the number of full calendar quarters starting January 1, 2015, and ending on the third anniversary of the grant date.	Stock price appreciation exceeding 10% above the fair market value of CRC stock at the time of the grant.

Forfeiture Provisions	Subject to attainment of the performance goal, shares of stock will become non-forfeitable on the vesting date.	Stock options will become non-forfeitable on the applicable vesting dates.
	If the grantee dies, becomes permanently disabled, retires with our consent, or is terminated without cause for our convenience prior to the vesting date, then the grantee will forfeit a pro rata portion of the shares based on the days remaining until the vesting date.	If the grantee dies, becomes permanently disabled, retires with our consent, or is terminated without cause for our convenience prior to the final vesting date, then the grantee will forfeit a pro rata portion of the unvested stock options based on the days remaining until the final vesting date. Vested stock options will remain exercisable through the term of the original award.
	If the grantee terminates voluntarily or is terminated for cause prior to the vesting date, all of the shares will be forfeited.	If the grantee terminates voluntarily or is terminated for cause prior to the final vesting date, all unvested stock options will be forfeited.
		Vested stock options will be exercisable for 90 days following the termination of employment subject to the expiration of the 7-year exercise period, and will be forfeited after that date.
Change in Control	In the event of a change in control prior to the vesting date, if a grantee is terminated by us as a result of the change in control, unvested restricted stock awards will become non-forfeitable.	In the event of a change in control prior to the final vesting date, if a grantee is terminated by us as a result of the change in control, unvested stock options will vest and become exercisable.
	In the event of a change in control after the vesting date, but prior to certification of the performance threshold, the shares of stock will become non-forfeitable.	Vested stock options will remain exercisable through the term of the original award.

2015 Annual Incentive Design

In February 2015, the CRC Compensation Committee enlisted the services of Meridian to help design the 2015 annual incentive. The new annual incentive is designed to align individual bonus awards with overall Company performance with a focus on key metrics and appropriate operational and strategic decisions intended to increase stockholder value. Prominent in the design is the Value Creation Index ("VCI"), a measure that the Compensation Committee believes is an effective indicator of stockholder value creation.

Under the approved design, payout of the 2015 annual incentive will be evaluated based on the following performance components and weightings against predetermined targets:

Performance Component	Weighting
Value Creation Index (VCI)	25%
Production	15%
Unit Cost	10%
Health, Environment and Safety	10%
Strategic and Operational Objectives	40%

Award opportunities under the 2015 annual incentive will range from 0% - 200% of target incentive amounts approved for each executive and will be paid in cash.

Individual Compensation Arrangements

Set forth below are descriptions of the initial annual compensation program for our named executive officers, as approved by the Occidental Compensation Committee prior to the Spin-off. Base salaries and annual incentive targets reflect the annual rates that were in effect at the time of the Spin-off. Long-term incentives reflect the grant date values of awards made in 2014.

Todd A. Stevens—President and Chief Executive Officer

Mr. Stevens, a 19-year veteran of Occidental, was appointed President, Chief Executive Officer and director of CRC in July 2014. Mr. Stevens served as Vice President—Corporate Development of Occidental Petroleum Corporation from August 2012 to July 2014. In that role, he led Occidental’s growth-focused initiatives including mergers and acquisitions, land management and worldwide exploration, and played a key role in the capital allocation process. From April 2008 to September 2012, Mr. Stevens was Vice President—California Operations, Oxy Oil & Gas and from October 2004 to August 2012, Mr. Stevens was Vice President—Acquisition and Corporate Finance of Occidental Petroleum Corporation.

Initial Compensation Program	Target Value on Grant Date
Base Salary	\$ 825,000
Annual Incentive at Target	\$ 825,000
Long-Term Incentive	
Restricted Stock Award	\$ 2,000,000
Stock Option Award	\$ 3,000,000
Total Annual Cash and Equity Compensation at Target	<u>\$ 6,650,000</u>

Marshall (Mark) D. Smith—Senior Executive Vice President and Chief Financial Officer

Mr. Smith was appointed Senior Executive Vice President and Chief Financial Officer of CRC in July 2014. He most recently served as Senior Vice President of Ultra Petroleum Corp. from January 2011 to July 2014 and served as its Chief Financial Officer from July 2005 to July 2014. Mr. Smith’s 32 years of experience in the energy industry spans operations, strategic planning, corporate finance and business development. He began his career as a petroleum engineer working at both major and independent oil companies, later focusing on mergers, acquisitions and corporate finance advisory assignments. Mr. Smith served as Vice President of Upstream Business Development at Constellation Energy from 2004 to 2005. He was Vice President of Business Development at J.M. Huber Energy from 2002 to 2004, and Chief Financial Officer of Gulf Liquids, Inc. from 2001 to 2002.

Initial Compensation Program	Target Value on Grant Date
Base Salary	\$ 600,000
Annual Incentive at Target	\$ 600,000
Long-Term Incentive	
Restricted Stock Award	\$ 1,200,000
Stock Option Award	\$ 1,800,000
Total Annual Cash and Equity Compensation at Target	<u>\$ 4,200,000</u>

William E. Albrecht—Executive Chairman

Mr. Albrecht was appointed as Executive Chairman and Chairman of our Board of Directors in July 2014. Mr. Albrecht served as Vice President of Occidental from May 2008 to July 2014 and as President, Oxy Oil & Gas, Americas from January 2012 to July 2014. With more than 35 years of industry experience, Mr. Albrecht was responsible for Occidental’s oil and gas operations in North and South America, including its health, environment and safety, government relations and social responsibility activities. He joined Occidental in 2007 as Vice President, California Operations.

Initial Compensation Program	Target Value on Grant Date
Base Salary	\$ 500,000
Annual Incentive at Target ⁽¹⁾	\$ 500,000
Long-Term Incentive	
Restricted Stock Award	\$ 2,000,000
Stock Option Award	\$ 2,000,000
Total Annual Cash and Equity Compensation at Target	<u>\$ 5,000,000</u>

(1) For 2014, Mr. Albrecht's annual incentive target remained at the Occidental approved amount of \$750,000. On January 1, 2015, it was reduced to \$500,000.

Roy Pineci—Executive Vice President—Finance

Mr. Pineci was appointed Executive Vice President—Finance in July 2014. Mr. Pineci served as Vice President and Controller of Occidental Petroleum Corporation from November 2008 to July 2014, and served as Senior Vice President, Occidental Oil and Gas from November 2007 to November 2008. He served as Vice President, Internal Audit for Occidental Petroleum Corporation from June 2005 to October 2007. Prior to joining Occidental, Mr. Pineci was a Partner at KPMG LLP in Los Angeles where he worked from 2002 through May 2005 and worked at Arthur Andersen LLP from 1985 to 2002 where he was a partner from 1997.

Initial Compensation Program	Target Value on Grant Date
Base Salary	\$ 410,000
Annual Incentive at Target	\$ 307,500
Long-Term Incentive	
Restricted Stock Award	\$ 680,000
Stock Option Award	\$ 1,020,000
Total Annual Cash and Equity Compensation at Target	<u>\$ 2,417,500</u>

Darren Williams—Executive Vice President—Exploration

Mr. Williams was appointed Executive Vice President—Exploration in September 2014. Mr. Williams has 20 years of experience in the oil and gas industry, working 17 of those years for Marathon Oil in London, Houston and Oklahoma City. Mr. Williams has broad experience and a proven track record in both conventional and unconventional exploration programs. Mr. Williams served as Africa Exploration Manager and President of Marathon Upstream Gabon Limited from May 2013 to September 2014. From September 2010 to May 2013 he served as Oklahoma Subsurface Manager where he managed the Woodford shale development program and established Marathon’s Oklahoma Resource Basin growth strategy. From 2008 to 2010, Mr. Williams served as Gulf of Mexico Exploration and Appraisal Manager overseeing participation in the Gunflint and Shenandoah discoveries and from 2004 to 2008 he managed teams responsible for discovery of the Droshky field and rebuilding Marathon’s deepwater Gulf of Mexico inventory. From 1997 to 2004, Mr. Williams held various roles exploring assets in Europe, Africa & the Gulf of Mexico.

Initial Compensation Program	Target Value on Grant Date
Base Salary	\$ 450,000
Annual Incentive at Target	\$ 405,000
Long-Term Incentive	
Restricted Stock Award	\$ 800,000
Stock Option Award	\$ 1,200,000
Total Annual Cash and Equity Compensation at Target	<u>\$ 2,855,000</u>

Other Compensation and Benefits

In addition to the three components of the executive compensation program described above, we provided the following programs to our named executive officers.

Qualified Defined Contribution Plan—All of our employees are eligible to participate in a tax-qualified, defined contribution plan. The defined contribution plan provides for periodic cash contributions by us based on annual cash compensation and employee deferrals. Employees are permitted to contribute into the plan a percentage of their annual salary and bonus up to the annual limit set by IRS regulations. Employees are able to direct their account balances to a variety of investments.

Nonqualified Defined Contribution Plan— Substantially all employees, including our named executive officers, whose participation in our qualified defined contribution plan is limited by applicable tax laws are eligible to participate in our supplemental savings plan (the “SSP”), a nonqualified defined contribution plan, which provides additional retirement benefits outside of those limitations starting in 2015.

Annual allocations for each participant are generally intended to restore the amounts that would have been contributed to our qualified defined contribution plan but for certain tax law limitations, and certain employer allocations are subject to a vesting schedule that requires the completion of three years of service. Vested account balances will be payable following separation from service.

Interest on SSP account balances is allocated monthly to each participant’s account. The amount of interest earnings is calculated using a daily rate equal to the sum of (i) the yield on five-year U.S. Treasury Constant Maturities based on a monthly frequency from the prior month divided by 365 and (ii) 0.167% divided by the number of days in the applicable month. Each of CRC’s named executive officers is eligible to participate in the SSP.

In addition, we sponsor a supplemental retirement plan (the “SRP II”), which was established for purposes of the assumption by us of certain liabilities under the Occidental Petroleum Corporation Supplemental Retirement Plan II. The SRP II also provided for an employer allocation for the month of December 2014, and all account balances under the SRP II are fully vested at all times. Account balances under the SRP II are credited with interest on a monthly basis based on the sum of 0.167% plus the yield on five-year U.S. Treasury Constant Maturities based on a monthly frequency for the monthly processing period.

In order to provide greater financial planning flexibility to participants while not increasing costs under the plan, the SRP II allows in-service distribution of a participant’s account at a specified age, but not earlier than age 60, as elected by the participant when initially participating in the plan. After a participant receives a specified age distribution, future allocations under the SRP II and earnings on those allocations are to be distributed in the first 70 days of each following year.

Nonqualified Deferred Compensation Plan—Certain management and other highly compensated employees (including each of our named executive officers) are eligible to participate in our nonqualified deferred compensation plan (the “DCP”). Under the DCP, participants are able to elect to defer a portion of their base salary and annual bonus for a given year. Each year, we will allocate an additional amount to a DCP participant’s account equal to the amounts that are not contributed to the qualified and nonqualified defined contribution plans due to the deferrals of compensation under the DCP for such year. Deferred amounts will earn interest based on the yield on five-year U.S. Treasury Constant Maturities based on a monthly frequency plus 2%, converted to a monthly allocation factor. Vested account balances will be payable following separation from service, or upon attainment of a specified age elected by the participant.

Tax Preparation and Financial Planning—Our senior executives, including each of the named executive officers, are eligible to receive reimbursement, up to certain annual limits, for income tax preparation, financial planning and investment advice, including legal advice related to tax and financial matters.

Insurance—We offer a variety of health coverage options to all employees. Named executive officers participate in these plans on the same terms as other employees. In addition, for all employees above a certain job level, we pay for an annual physical examination. We provide all non-bargained employees with life insurance equal to twice the employee’s base salary. We also provide senior executives, including the named executive officers, with excess liability insurance coverage.

Severance Benefits—We maintain a notice and severance pay plan that, in connection with a qualifying termination of employment, provides

for up to 12 months of base salary and other insurance coverage, depending on years of service, for non-bargained employees, including the named executive officers.

Stock Ownership Guidelines

We have minimum stock ownership guidelines for senior executives. The target direct and indirect ownership level for the Chief Executive Officer is six times annual base salary, and for the other named executive officers, is three times annual base salary. Executives have five years to attain their required ownership levels.

CRC Long-Term Incentive Plan

Prior to the Spin-off, the California Resources Corporation Long-Term Incentive Plan (the “LTIP”) was adopted to attract and retain our employees, executives and directors. The LTIP provides for the grant of cash-based and equity-based awards with respect to our common stock. The LTIP authorizes awards to be granted covering up to 25,000,000 shares of our common stock, subject to adjustment in accordance with the terms of the LTIP upon certain changes in capitalization and similar events. Awards payable in cash or payable in cash or shares, including restricted shares, that are forfeited, cancelled (other than for tax withholdings) or do not vest, and shares that are subject to awards that expire or for any reason are terminated, cancelled, or fail to vest, will be available for subsequent awards under the LTIP. If an award under the LTIP is or may be settled only in cash, such award will not be counted against the share limit in the LTIP.

During the term of the LTIP, no participant may be granted awards with respect to more than 12,500,000 shares of our common stock, subject to adjustment in accordance with the terms of the LTIP. In addition, under the LTIP the maximum amount of compensation that can be paid with respect to any performance-based awards denominated in cash granted to any one individual during any calendar year is \$20,000,000.

We have broad discretion under the LTIP to determine the types of awards that are granted to eligible persons. Upon a “change in control” (as defined in the LTIP), unless otherwise determined by the committee appointed to administer the LTIP (the “Committee”), all awards outstanding pursuant to the plan will fully vest and, if applicable, become exercisable. In addition, upon any change that is made to our capitalization, such as a stock split, stock combination, stock dividend, exchange of shares or any other recapitalization, appropriate adjustments may be made by the Committee in the shares subject to the LTIP and awards under the LTIP. For a description of the performance criteria, see "Components of the Initial Compensation Program" above.

Conversion of Occidental Compensation Awards in Connection with Spin-off

Each equity and cash based long-term incentive award with respect to Occidental common stock (other than Occidental restricted shares, which are described below) that was held by our named executive officers was converted upon the Spin-off into an award of shares of our restricted common stock (a “RSA”), with the number of shares determined based upon the trading price of Occidental's common stock preceding the Spin-off and our common stock following the Spin-off and (a) the payout of such incentive award at target performance, in the case of performance cycles with more than one year of performance remaining as of the Spin-off, and (b) the payout of such incentive award based upon actual performance, calculated as of a date on or prior to the Spin-off (as was determined by the Occidental Compensation Committee), in the case of performance cycles with less than one year of performance remaining as of the Spin-off. From and after the Spin-off, such restricted shares are subject to service-based vesting requirements satisfied through continued service with us the same as the time-based vesting requirements that were applicable to the corresponding Occidental incentive award and, in the case of performance-based awards held by individuals with a title of executive vice president or above (including our named executive officers), performance-based vesting requirements.

Each share of restricted Occidental common stock held by our named executive officers was converted into an RSA, with the number of shares determined based upon the trading price of our common stock following the Spin-off. The restricted common stock will vest based upon the same schedule as the prior Occidental restricted share, subject to continued service with us and, in the case of awards held by individuals with a title of executive vice president or above (including our named executive officers), performance-based vesting requirements established by the CRC Compensation Committee.

The RSAs held by our named executive officers are performance-based awards with payouts that depend on the outcome of the performance criteria and the price of our stock on the award certification date, as applicable, with the possibility of no payout if performance criteria are not met. These are long-term awards with two-year and three- to seven-year performance periods, as applicable, that, based on achievement of performance criteria, will vest or become non-forfeitable between 2015 and 2021.

CRC Employee Stock Purchase Plan

We adopted the California Resources Corporation 2014 Employee Stock Purchase Plan (the “ESPP”), effective January 1, 2015, which provides our employees (including our named executive officers), 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 day of each offering period or the last day of each offering period, whichever amount is less.

The maximum number of shares of our common stock which may be issued pursuant to the ESPP is 5,000,000, 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 under the ESPP.

Settlement and Termination of Occidental Retention and Separation Arrangements

In connection with the Spin-off, we assumed retention and separation arrangements between certain of our named executive officers and Occidental, which were subsequently settled and terminated, as described below.

In February 2013, Occidental provided an arrangement regarding retention payment and separation benefits (the “Retention and Separation Arrangements”) in certain circumstances for Messrs. Stevens, Albrecht and Pineci, none of whom has as employment agreement that addresses termination payments and benefits. These arrangements replaced any notice and severance pay that they would have otherwise received under the applicable Occidental severance plan.

Had Messrs. Stevens, Albrecht and Pineci remained employees of Occidental, they would have received a retention payment of two times their then-current annual base salary, payable in one lump sum cash payment one year after a new Chief Executive Officer of Occidental began employment. In addition, had Messrs. Stevens, Albrecht and Pineci been terminated without cause prior to December 31, 2014, they would have received certain enhanced severance benefits.

Immediately prior to the Spin-off, in connection with the payment of a transition bonus of \$1,250,000, Occidental settled and terminated the Retention and Separation Arrangement with Mr. Albrecht. In December 2014, the CRC Compensation Committee considered the agreements that were assumed from Occidental and decided to terminate the remaining Retention and Separation Arrangements because they did not consider it desirable to continue the connection between our executives’ benefits under these legacy arrangements and the status of Occidental’s management. Messrs. Stevens and Pineci agreed to settle and terminate the future payments under the Retention and Separation Arrangements in exchange for lump sum cash payments of \$850,000 and \$820,000, respectively. We believe these amounts would be smaller than the potential payments we would have otherwise been obligated to make at a future date under the Retention and Separation Agreements, which would have been based on each executive’s compensation levels at that time.

One-Time Sign-On Arrangements

In connection with the commencement of their employment during 2014, Messrs. Smith and Williams received one-time sign-on benefits in the form of cash payments and restricted stock grants to help attract them to CRC and to make up for unvested equity-based awards they forfeited from their prior employers.

Mr. Smith received a cash sign-on bonus of \$500,000 and a restricted stock grant with a grant date value of \$2,500,000, which will vest, subject to attainment of an EBITDA performance goal consistent with the RSAs described above, at the end of two years following the grant date.

Mr. Williams received a cash sign-on bonus of \$600,000 and a restricted stock grant with a grant date value of \$600,000, which will vest, subject to attainment of an EBITDA performance goal consistent with the RSAs described above, at the end of three years following the grant date.

Tax Considerations

Section 162(m) of the U.S. Internal Revenue Code of 1986, as amended, places a limit of \$1 million on the amount of non-performance-based compensation that we may deduct in any one year with respect to certain of our highest-paid executive officers. Certain qualified performance-

based compensation is not subject to the deduction limit. Although tax consequences are considered in our compensation decisions, we have not adopted a policy that all compensation must be deductible. Rather, our Compensation Committee gives priority to the overall compensation objectives discussed above.

EXECUTIVE COMPENSATION TABLES

Summary Compensation Table

At the time of the Spin-off, we were a newly-formed entity and had not historically paid compensation or had employees (including named executive officers). The tables below and the accompanying footnotes summarize the aggregate 2014 compensation paid by us and Occidental for the individuals who comprise our named executive officers.

Name	Year	Salary(1)	Bonus(2)	Stock Awards(3)	Option Awards(4)	Non-Equity Incentive Plan Compensation (5)	Change in Pension Value and Nonqualified Deferred Compensation Earnings	All Other Compensation (6)	Total
Todd A. Stevens President and Chief Executive Officer	2014	\$ 525,000	\$ 865,000	\$ 2,000,000	\$ 3,000,000	\$ 525,000	—	\$ 1,158,135	\$ 8,073,135
Marshall D. Smith Senior Executive Vice President and Chief Financial Officer	2014	\$ 245,455	\$ 1,175,000	\$ 3,700,000	\$ 1,800,000	—	—	\$ 117,556	\$ 7,038,011
William E. Albrecht Executive Chairman	2014	\$ 614,583	\$ 750,000	\$ 2,000,000	\$ 2,000,000	—	—	\$ 1,803,726	\$ 7,168,309
Roy Pineci Executive Vice President - Finance	2014	\$ 410,000	\$ 310,000	\$ 1,360,000	\$ 1,020,000	—	—	\$ 998,707	\$ 4,098,707
Darren Williams Executive Vice President - Exploration	2014	\$ 133,168	\$ 1,005,000	\$ 1,400,000	\$ 1,200,000	—	—	\$ 15,790	\$ 3,753,958

- (1) For Mr. Stevens, reflects nine months at his prior Occidental salary of \$425,000 and three months at his CRC salary of \$825,000.
For Mr. Smith, reflects his CRC salary of \$600,000 for the period beginning on his hire date of August 5, 2014.
For Mr. Albrecht, reflects eleven months at his prior Occidental salary of \$625,000 and one month at his CRC salary of \$500,000.
For Mr. Pineci, his salary remained unchanged at \$410,000 for the entire year.
For Mr. Williams, reflects his CRC salary of \$450,000 for the period beginning on his hire date of September 15, 2014.
- (2) The amounts shown include the executive’s annual incentive award, which was paid in the first quarter of 2015, plus cash sign-on awards of \$500,000 and \$600,000 paid to Messrs. Smith and Williams, respectively.
- (3) Awards that are payable in stock are stated at the grant date fair value, which incorporates the value of our stock as well as the estimated payout percentage as of the grant date. For Mr. Smith, includes a one-time sign-on restricted stock grant of \$2,500,000. For Mr. Pineci, includes a restricted stock replacement award for an Occidental cash-based performance award of \$680,000. For Mr. Williams, includes a one-time sign-on restricted stock grant of \$600,000.
- (4) The amounts shown represent the grant date fair value of options granted as computed in accordance with GAAP, excluding forfeiture estimates, as more fully described in Note 11 to Consolidated and Combined Financial Statements in CRC’s Form 10-K for the year ended December 31, 2014.
- (5) The amount for Mr. Stevens reflects the cash portion of an Occidental Return on Assets Incentive award that was granted in 2009 and paid in 2014.
- (6) The following table shows “All Other Compensation” amounts for 2014.

All Other Compensation

	Todd A. Stevens	Marshall D. Smith	William E. Albrecht	Roy Pineci	Darren Williams
Qualified Plans ^(a)	\$18,633	\$9,715	\$18,633	\$18,633	\$6,530
Supplemental Plans ^(b)	\$139,704	\$17,389	\$172,958	\$91,658	\$6,225
Retention Agreement Settlement	\$850,000	\$0	\$1,250,000	\$820,000	\$0
	(c)	(d)	(e)	(f)	(g)

Personal Benefits	\$149,798	\$90,452	\$362,135	\$68,416	\$3035
Total	\$1,158,135	\$117,556	\$1,803,726	\$998,707	\$15,790

- (a) The amount shown is the sum of the company contributions to the qualified defined contributions retirement and savings plans- the California Resources Corporation Savings Plan and the Occidental Petroleum Corporation Savings Plan (the “Qualified Plans”). Includes company matching contributions and retirement contributions.
- (b) The amount shown is the sum of the company contributions to the nonqualified defined contribution plans and nonqualified deferred compensation plans and a cash restoration payment for amounts that were not contributed to the qualified or nonqualified plans (the “Supplemental Plans”) due to the Spin-off (\$1,083 each for Messrs. Stevens, Smith, Albrecht and Pineci and \$17 for Mr. Williams).
- (c) Includes tax preparation and financial counseling (\$23,104), excess liability insurance, dividend equivalents paid on unvested Occidental restricted stock incentive awards (\$124,080), and physical examinations.
- (d) Includes relocation benefits beyond those generally available to employees (\$32,190), tax reimbursement related to the relocation benefits (\$32,674), dividend equivalents paid on unvested Occidental restricted stock incentive awards (\$18,162), personal use of Occidental’s aircraft and CRC’s fractional interest in aircraft, and tax reimbursement related to the amounts paid by the company for spousal travel (\$3,574).
- (e) Includes tax preparation and financial counseling, excess liability insurance, physical examinations, dividend equivalents paid by Occidental on unvested restricted stock incentive awards (\$140,523), and personal use of Occidental’s aircraft and CRC’s fractional interest in aircraft and commuting expenses (\$183,795) and tax reimbursement related to the amounts paid by the company for commuting expenses and spousal travel (\$21,202 and \$6,145, respectively).
- (f) Includes tax preparation and financial counseling, excess liability insurance, physical examinations and dividend equivalents paid by Occidental on unvested restricted stock incentive awards (\$64,406).
- (g) Includes tax reimbursement related to the relocation benefits (\$1,850), and tax reimbursement related to the amounts paid by the company for spousal travel (\$1,185).

Grants of Plan-Based Awards

The table below summarizes the following plan-based awards granted in 2014 to our named executive officers: RSAs and Stock Option Awards (“Options”).

During 2014, plan-based awards were granted to our named executive officers by both us and Occidental. Awards that were granted by Occidental during 2014 and converted to CRC awards at the Spin-off are included in this table. Awards that were granted by Occidental in prior years and converted to CRC awards at the Spin-off are included in the Outstanding Equity Awards table in the following section.

Name / Type of Grant	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares or Units	All Other Option Awards: Number of Securities Underlying Options	Exercise or Base Price of Option Awards	Grant Date Fair Value of Stock and Option Awards
		Threshold (\$)	Target (\$)	Maximum (\$)	Threshold # Shares	Target # Shares	Maximum # Shares	(# of Shares)	(# of Shares)	(\$)	(\$)
Todd A. Stevens											
Annual Incentive(1)		\$8,250	\$825,000	\$1,650,000							
RSA(2)	12/1/2014					\$237,710					\$2,000,000
Options(3)	12/1/2014								\$1,515,152	\$8.11	\$3,000,000
Marshall D. Smith											
Annual Incentive(1)		\$6,000	\$600,000	\$1,200,000							
RSA(4)	12/1/2014					\$305,649					\$2,500,000
RSA(5)	12/1/2014					\$170,455					\$1,200,000
Options(3)	12/1/2014								\$909,091	\$8.11	\$1,800,000
William E. Albrecht											
Annual Incentive(1)		\$7,500	\$750,000	\$1,500,000							
RSA(2)	12/1/2014					\$237,710					\$2,000,000
Options(3)	12/1/2014								\$1,010,102	\$8.11	\$2,000,000

Roy Pineci							
Annual Incentive(1)		\$3,075	\$307,500	\$615,000			
RSA(2)	12/1/2014			\$80,820			\$680,000
Options(3)	12/1/2014				\$515,152	\$8.11	\$1,020,000
Darren Williams							
Annual Incentive(1)		\$4,050	\$405,000	\$810,000			
RSA(6)	12/1/2014			\$73,974			\$600,000
RSA(5)	12/1/2014			\$113,637			\$800,000
Options(3)	12/1/2014				\$606,061	\$8.11	\$1,200,000

(1) Payout of annual incentive ranges from 0% to 200% of target. Threshold amounts shown at 1% of target. For Messrs. Smith and Williams, employment offers guaranteed payout not less than target for 2014.

- (2) Awards were granted as Occidental time-vested restricted stock awards on July 9, 2014 and were converted to CRC performance-based restricted stock awards at the time of the Spin-off as described in "Conversion of Occidental Compensation Awards in Connection with Spin-off" above. Dollar value shown represents the estimated Occidental grant date fair value of the full number of shares granted which become non-forfeitable on the later of July 8, 2017, through which date the executive is required to remain employed, and the date our Compensation Committee certifies the achievement of the performance goal, which must be met no later than June 30, 2021. The RSA award does not have threshold to maximum payout ranges.
- (3) The amounts shown represent the grant date fair value of options granted as computed in accordance with GAAP, excluding forfeiture estimates, as more fully described in Note 11 to Consolidated and Combined Financial Statements in CRC's Form 10-K for the year ended December 31, 2014. The exercise price was determined based on a 10% premium over the CRC closing stock price on the grant date.
- (4) A one-time sign-on restricted stock grant with a grant value of \$2,500,000 was granted as an Occidental time-vested restricted stock award on August 5, 2014 and was converted to CRC performance-based restricted stock award at the time of the Spin-off as described in "Conversion of Occidental Compensation Awards in Connection with Spin-off" above. Dollar value shown represents the estimated Occidental grant date fair value of the full number of shares granted which become non-forfeitable on the later of August 4, 2016, through which date the executive is required to remain employed, and the date our Compensation Committee certifies the achievement of the performance goal, which must be met no later than June 30, 2020. The RSA award does not have threshold to maximum payout ranges.
- (5) Dollar value shown represents the estimated grant date fair value of the full number of shares granted which become non-forfeitable on the later of November 30, 2017, through which date the executive is required to remain employed, and the date our Compensation Committee certifies the achievement of the performance goal, which must be met no later than September 30, 2021. The RSA award does not have threshold to maximum payout ranges.
- (6) A one-time sign-on restricted stock grant date with a grant value of \$600,000 was granted as an Occidental time-vested restricted stock award on September 15, 2014 and was converted to CRC performance-based restricted stock award at the time of the Spin-off as described in "Conversion of Occidental Compensation Awards in Connection with Spin-off" above. Dollar value shown represents the estimated Occidental grant date fair value of the full number of shares granted which become non-forfeitable on the later of September 14, 2017, through which date the executive is required to remain employed, and the date our Compensation Committee certifies the achievement of the performance goal, which must be met no later than June 30, 2021. The RSA award does not have threshold to maximum payout ranges.

Outstanding Equity Awards at December 31, 2014

The table below sets forth the outstanding equity awards held as of December 31, 2014 by our named executive officers, including RSAs and Options. For additional information relating to these awards, please read "Conversion of Occidental Compensation Awards in Connection with Spin-off."

Option Awards			Stock Awards		
					Equity Incentive Plan Awards: Payout Value of Unearned Shares,
Number of	Number of		Number of	Market	Equity Incentive Plan Awards: Payout Value of Unearned Shares,

Name / Type of Grant	Grant Date	Securities Underlying Unexercised Options (#) Exercisable	Securities Underlying Unexercised Options (#) Unexercisable	Option Exercise Price (\$)	Option Exercise Date	Shares or Units of Stock That Have Not Vested (#)	Value of Shares or Units That Have Not Vested (\$)(1)	Units or Other Rights That Have Not Vested (#)	Units or Other Rights That Have Not Vested (\$)(1)
Todd A. Stevens									
RSA(2)	12/1/2014							229,252	\$ 1,263,179
RSA(3)	12/1/2014							106,726	\$ 588,060
RSA(4)	12/1/2014							106,726	\$ 588,060
RSA(5)	12/1/2014							142,289	\$ 784,012
RSA(6)	12/1/2014							237,710	\$ 1,309,782
Options(7)	12/1/2014		1,515,152	\$ 8.11	11/30/2021				
Marshall D. Smith									
RSA(8)	12/1/2014							305,649	\$ 1,684,126
RSA(9)	12/1/2014							170,455	\$ 939,207
Options(7)	12/1/2014		909,091	\$ 8.11	11/30/2021				
William E. Albrecht									
RSA(2)	12/1/2014							229,252	\$ 1,263,179
RSA(3)	12/1/2014							177,864	\$ 980,031
RSA(4)	12/1/2014							177,864	\$ 980,031
RSA(5)	12/1/2014							237,152	\$ 1,306,708
RSA(6)	12/1/2014							237,710	\$ 1,309,782
Options(7)	12/1/2014		1,010,102	\$ 8.11	11/30/2021				
Roy Pineci									
RSA(2)	12/1/2014							108,895	\$ 600,011
RSA(3)	12/1/2014							44,797	\$ 246,831
RSA(4)	12/1/2014							89,593	\$ 493,657
RSA(5)	12/1/2014							96,659	\$ 532,591
RSA(6)	12/1/2014							80,820	\$ 445,318
Options(7)	12/1/2014		515,152	\$ 8.11	11/30/2021				
Darren Williams									
RSA(10)	12/1/2014							73,974	\$ 407,597
RSA(9)	12/1/2014							113,637	\$ 626,140
Options(7)	12/1/2014		606,061	\$ 8.11	11/30/2021				

- (1)The amounts shown represent the product of the number of shares or units shown in the column immediately to the left and the closing price on December 31, 2014 of our common stock as reported in the NYSE Composite Transactions, which was \$5.51.
- (2)CRC replacement award for award originally granted by Occidental on July 11, 2012. The shares are forfeitable until the later of July 10, 2015 and the certification by our Compensation Committee that the achievement of the performance threshold was met no later than June 30, 2019.
- (3)CRC replacement award for award originally granted by Occidental on July 22, 2013. The shares are forfeitable until the later of June 30, 2016 and the certification by our Compensation Committee that the achievement of the performance threshold was met no later than June 30, 2020.
- (4)CRC replacement award for award originally granted by Occidental on July 22, 2013. The shares are forfeitable until the later of July 21, 2016 and the certification by our Compensation Committee that the achievement of the performance threshold was met no later than June 30, 2020.
- (5)CRC replacement award for award originally granted by Occidental on July 22, 2013. The shares are forfeitable until the later of December 31, 2016 and the certification by our Compensation Committee that the achievement of the performance threshold was met no later than June 30, 2020.

- (6)CRC replacement award for award originally granted by Occidental on July 9, 2014. The shares are forfeitable until the later of July 8, 2017 and the certification by our Compensation Committee that the achievement of the performance threshold was met no later than June 30, 2021.
- (7)The exercise price was set at 10% above the closing market price of CRC stock on the grant date. One-third of the options become exercisable on each of the following dates: November 30, 2015, November 30, 2016, and November 30, 2017. Unexercised options expire on November 30, 2021.

- (8) CRC replacement award for award originally granted by Occidental on August 5, 2014. The shares are forfeitable until the later of August 4, 2016 and the certification by our Compensation Committee that the achievement of the performance threshold was met no later than June 30, 2020.
- (9) The shares are forfeitable until the later of November 30, 2017 and the certification by our Compensation Committee that the achievement of the performance threshold was met no later than September 30, 2021.
- (10) CRC replacement award for award originally granted by Occidental on September 15, 2014. The shares are forfeitable until the later of September 14, 2017 and the certification by our Compensation Committee that the achievement of the performance threshold was met no later than June 30, 2021.

Option Exercises and Stock Vested in 2014

The following table summarizes, for our named executive officers, the CRC and Occidental option and stock awards vested during 2014. No CRC option or stock awards vested during 2014. Prior to the Spin-off, certain Occidental stock awards vested, as indicated in the following the table.

Previously Granted Vested Option Awards Exercised and Previously Granted Stock Awards Vested in 2014

Name	Option Awards		Stock Awards(1)	
	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise (\$)	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting (\$)
Todd A. Stevens	0	\$0	15,539	\$1,561,359
Marshall D. Smith	0	\$0	0	\$0
William E. Albrecht	0	\$0	15,539	\$1,561,359
Roy Pineci	0	\$0	6,604	\$663,570
Darren Williams	0	\$0	0	\$0

- (1) Messrs. Stevens, Albrecht and Pineci had Occidental stock awards which vested in 2014 prior to the Spin-off resulting in the realized values indicated based on the number of Occidental shares vested and the closing price of Occidental common stock on the vesting date.

2014 Nonqualified Deferred Compensation Table

The following table sets forth for 2014 the contributions, earnings, withdrawals and balances under the SRP II and the DCP in which the named executive officers participated. Each of the named executive officers was fully vested in their respective aggregate balances shown below, which include amounts CRC assumed from Occidental plans in connection with the Spin-off. For additional information relating to these plans, see “Nonqualified Defined Contribution Plan” and “Nonqualified Deferred Compensation Plan,” above.

Name	Plan	Executive Contributions in 2014 (\$)(1)	Company Contributions in 2014 (\$)(2)	Aggregate Earnings in 2014 (\$)	Aggregate Withdrawals/ Distributions in 2014 (\$)(3)	Aggregate Balance at 12/31/2014 (\$)
Todd A. Stevens	SRP II	\$ 0	\$ 138,526	\$ 35,876	\$ 0	\$ 1,073,671
	DCP	\$ 58,500	\$ 95	\$ 22,999	\$ 0	\$ 658,403
Marshall D. Smith	SRP II	\$ 0	\$ 16,306	\$ 49	\$ 0	\$ 16,355
William E. Albrecht	SRP II	\$ 0	\$ 171,875	\$ 4,136	\$ 133,249	\$ 175,621

Roy Pineci	SRP II	\$	0	\$	90,575	\$	27,069	\$	0	\$	802,909
Darren Williams	SRP II	\$	0	\$	6,208	\$	9	\$	0	\$	6,217

- (1) No employee contributions are permitted in the SRP II.
- (2) Amounts represent company 2014 contributions to the SRP II, which are reported under “All Other Compensation” in the Summary Compensation Table.
- (3) Distribution made in February 2014 in accordance with the specified age elections described under "Nonqualified Defined Contribution Plan" above.

Potential Payments Upon Termination or Change in Control

Summary

Payments and other benefits payable to named executive officers in various termination circumstances and a change of control are subject to certain policies, plans and agreements. Following is a summary of the material terms of these arrangements.

Under our Notice and Severance Pay Plan, employees, including named executive officers without employment agreements (which includes our named executive officers), terminated in certain circumstances without cause or as a result of a change of control are eligible for up to 12 months base salary depending on years of service, two months of contributions pursuant to CRC’s qualified and nonqualified savings plans, and continued medical and dental coverage for the 12-month notice and severance period at the active employee rate.

Our LTIP has provisions that, in the event of a change in control, provide for the outstanding awards granted under such plan to become fully vested and exercisable unless the plan administrator determines, prior to the occurrence of the event, that benefits will not accelerate. This plan was approved by our sole stockholder when we were a subsidiary of Occidental. Notwithstanding the plan provisions, as of December 31, 2014, certain outstanding awards provided for partial vesting upon a termination of employment as a result of a change in control. In February 2015, the CRC Compensation Committee amended the terms of the outstanding awards to provide for full vesting upon a termination of employment as a result of a change in control.

Except as described in this summary and below under “Potential Payments,” we do not have any other agreements or plans that would have required us to provide compensation to our named executive officers in the event of a termination of employment or a change of control.

Potential Payments

In the discussion that follows, payments and other benefits payable upon various terminations and change of control situations are set out as if the conditions for payments had occurred and the terminations took place on December 31, 2014, and reflect the terms of applicable plans, agreements, offer letters and long-term incentive award agreements then in effect. The amounts set forth below are estimates of the amounts that would have been paid to each named executive officer upon his termination. The actual amounts to be paid out can be determined

only at the time of separation. The disclosures below do not take into consideration any requirements under Section 409A of the Internal Revenue Code, which could affect, among other things, the timing of payments and distributions.

The following payments and benefits, which are potentially available to all full-time salaried employees when their employment terminates, are not included in the amounts shown below:

- Notice and Severance Pay Plan payments and benefits.
- Life insurance proceeds equal to two times base salary, payable on death as available to all eligible employees.
- Amounts vested under our plans that are qualified under Section 401(a) of the Internal Revenue Code.
- Amounts vested under the Nonqualified Deferred Compensation arrangements.
- Bonus under our annual incentive plan that would have been earned as of year-end. The amounts that were earned in 2014 by the named executive officers are included in the Summary Compensation Table.
- Payout of unused accrued vacation.

Mr. Stevens. Mr. Stevens did not have an employment agreement. The following is a summary of the payments and benefits he would have been entitled to receive if the event specified occurred as of December 31, 2014.

Benefits and Payments Upon Termination	Retirement with CRC Consent	Death or Disability	Termination by Mr. Stevens or Termination for Cause	Termination without Cause	Change of Control (1)
Equity Compensation					
RSA Awards (2)	\$2,908,553	\$2,092,153	\$0	\$2,092,153	\$2,908,553
Option Awards (3)	\$0	\$0	\$0	\$0	\$0
TOTAL	\$2,908,553	\$2,092,153	\$0	\$2,092,153	\$2,908,553

Mr. Smith. Mr. Smith did not have an employment agreement. The following is a summary of the payments and benefits he would have been entitled to receive if the event specified occurred as of December 31, 2014.

Benefits and Payments Upon Termination	Retirement with CRC Consent, Death, or Disability	Termination by Mr. Smith or Termination for Cause	Termination without Cause	Change of Control (1)
Equity Compensation				
RSA Awards (2)	\$369,848	\$0	\$369,848	\$369,848
Option Awards (3)	\$0	\$0	\$0	\$0
TOTAL	\$369,848	\$0	\$369,848	\$369,848

Mr. Albrecht. Mr. Albrecht did not have an employment agreement. The following is a summary of the payments and benefits he would have been entitled to receive if the event specified occurred as of December 31, 2014.

Benefits and Payments Upon Termination	Retirement with CRC Consent	Death or Disability	Termination by Mr. Albrecht or Termination for Cause	Termination without Cause	Change of Control (1)
Equity Compensation					
RSA Awards (2)	\$4,012,051	\$2,651,401	\$0	\$2,651,401	\$4,012,051
Option Awards (3)	\$0	\$0	\$0	\$0	\$0
TOTAL	\$4,012,051	\$2,651,401	\$0	\$2,651,401	\$4,012,051

Mr. Pineci. Mr. Pineci did not have an employment agreement. The following is a summary of the payments and benefits he would have been entitled to receive if the event specified occurred as of December 31, 2014.

Benefits and Payments Upon Termination	Retirement with CRC Consent	Death or Disability	Termination by Mr. Pineci or Termination for Cause	Termination without Cause	Change of Control (1)
Equity Compensation					
RSA Awards (2)	\$1,584,114	\$1,105,708	\$0	\$1,105,708	\$1,584,114
Option Awards (3)	\$0	\$0	\$0	\$0	\$0
TOTAL	\$1,584,114	\$1,105,708	\$0	\$1,105,708	\$1,584,114

Mr. Williams. Mr. Williams did not have an employment agreement. The following is a summary of the payments and benefits he would have been entitled to receive if the event specified occurred as of December 31, 2014.

Benefits and Payments Upon Termination	Retirement with CRC Consent, Death, or Disability	Termination by Mr. Williams or Termination for Cause	Termination without Cause	Change of Control (1)
Equity Compensation				
RSA Awards (2)	\$57,883	\$0	\$57,883	\$57,883
Option Awards (3)	\$0	\$0	\$0	\$0
TOTAL	\$57,883	\$0	\$57,883	\$57,883

- (1) Amounts shown would have become payable only upon a termination of employment as a result of a change in control. Upon a change in control without a termination of employment, outstanding equity awards would have continued to vest according to their regular vesting schedules except for the RSA awards granted as replacement awards for the Occidental awards originally granted July 11, 2012. Those awards for Messrs. Stevens, Albrecht and Pineci would have immediately vested on a pro rata basis, resulting in payments of \$1,042,845, \$1,042,845 and \$495,355, respectively. Amounts reflect award terms in effect on December 31, 2014. As described above, the award terms were amended on February 6, 2015 to provide for full vesting of RSA awards in the event of a change in control prior to the vesting date with a termination of employment as a result of the change in control. The additional amounts that would have been received under the amended terms were: \$1,624,541 for Mr. Stevens, \$2,253,485 for Mr. Smith, \$1,827,678 for Mr. Albrecht, \$734,296 for Mr. Pineci and \$975,854 for Mr. Williams.
- (2) Represents the product of the year-end price of CRC common stock of \$5.51 and the number of shares of restricted stock that become vested upon occurrence of the indicated event.
- (3) Under the terms of the option awards, options become (i) vested on a prorated based upon the earlier of the executive’s termination of employment for retirement, disability, death, or involuntary termination or

(i) fully vested upon termination of employment as a result of a change in control. Option award values are \$0 because in each case the option exercise price exceeded our year-end common stock price of \$5.51.

Director Compensation

In order to have our director compensation program in effect at the time of the Spin-off, our initial director compensation program was approved by the Occidental Compensation Committee. The CRC Board of Directors will make future decisions regarding our director compensation program.

Pay Governance LLC, an independent compensation consultant, assisted in the design of our initial director compensation program. Specifically, Pay Governance worked with Occidental to develop a compensation peer group for purposes of conducting market analyses, as described above under “—Peer Companies” and to determine the level and form of outside director compensation immediately following the Spin-off.

Program Objectives

Our initial director compensation program was designed to be consistent with the programs of compensation peer companies. The following matters were considered important to development of our initial director compensation program:

- Market practices of our compensation peer companies, as well as a group of 100 general industry companies similar in size to us, targeting a compensation package between the median of those two groups.
- The need to recruit independent directors.
- The need to provide us with appropriate initial programs immediately following the Spin-off, recognizing that our Board of Directors will be responsible for program design following the Spin-off.

Program Elements

The elements of our approved outside director compensation program are as follows:

- Outside directors receive an annual cash board retainer of \$100,000.
- Board committee chairpersons receive an additional annual cash retainer of \$15,000.
- The Lead Independent Director receives an additional annual cash retainer of \$20,000.
- Outside directors receive an annual equity award relating to our common stock equivalent to \$150,000 on the grant date. The equity award will generally vest one year following the grant date.
- A stock ownership guideline of five times the annual cash board retainer applies to outside directors and must be attained within five years of election to our Board of Directors.

2014 Compensation of Directors

Because of the November 30, 2014 Spin-off date, outside directors received one-twelfth of the annual cash retainer amounts and one-half of the annual equity award described above. The following table sets forth the total compensation for 2014 for each of the non-employee directors who served in 2014:

Name	Fees Earned or Paid in Cash	Stock Awards(1)	All Other Compensation(2)	Total
Justin A. Gannon	\$9,583	\$75,000	\$0	\$84,583
Ronald L. Havner, Jr.	\$8,333	\$75,000	\$0	\$83,333
Harold M. Korell	\$11,250	\$75,000	\$1,860	\$88,110
Richard W. Moncrief	\$9,583	\$75,000	\$0	\$84,583
Avedick B. Poladian	\$8,333	\$75,000	\$0	\$83,333
Robert V. Sinnott	\$9,583	\$75,000	\$0	\$84,583
Timothy J. Sloan	\$8,333	\$75,000	\$0	\$83,333

(1) Restricted Stock Unit awards were granted to each outside director based on the simple average volume weighted average price of CRC common stock for the four trading days immediately following the Spin-off, which was \$7.04 per share. Amounts in the table reflect the grant date fair value of such awards, calculated in accordance with GAAP, excluding forfeiture estimates, as more fully described in Note 11 to the Consolidated and Combined Financial Statements herein regarding assumptions underlying valuation of equity awards. The RSU awards will vest at the end of one year from the Spin-off date or, if earlier, upon the occurrence of a change in control or the outside director's termination of service by reason of death or disability. None of these RSU awards were vested as of December 31, 2014.

(2) None of the outside directors received any fees or payments for services other than as a director. Amounts shown are for tax reimbursements related to the amounts paid by the company for spousal travel.

Security Ownership of Directors, Management and Certain Beneficial Holders

The following table sets forth certain information regarding beneficial ownership of common stock as of March 10, 2015 (unless otherwise indicated) of (1) each person known by us to own beneficially more than 5% of our outstanding common stock, (2) our named executive officers (as defined herein), (3) each of our directors and director nominees, and (4) all of our executive officers and directors as a group. Unless otherwise indicated, each of the persons below has sole voting and investment power with respect to the shares beneficially owned by such person.

Name and Address of Beneficial Owner (1)	Amount of Beneficial Ownership	Percent of Class (2)
Occidental Petroleum Corporation (3)	71,500,000	18.5%
Soroban Capital Partners LP (4)	38,469,999	9.98%
Southeastern Asset Management, Inc. (5)	33,481,500	8.8%
Longleaf Partners Small-Cap Fund (6)	33,090,500	8.7%
The Vanguard Group (7)	19,441,822	5.05%
William E. Albrecht	1,111,830	*
Justin A. Gannon	0	*
Ronald L. Havner, Jr.	0	*
Catherine A. Kehr ⁽⁸⁾	0	*
Harold M. Korell	100,000	*
Richard W. Moncrief	800	*
Avedick B. Poladian	14,796	*
Robert V. Sinnott	0	*
Timothy J. Sloan	0	*
Todd A. Stevens	839,493	*
Roy Pineci	471,267	*
Marshall D. Smith	491,104	*
Darren Williams	187,611	*
Executive officers and directors as a group (consisting of 19 persons)	4,133,086	1.07%

* Less than 1%.

- (1) Unless otherwise noted, the address for each beneficial owner is c/o California Resources Corporation, 10889 Wilshire Boulevard, Los Angeles, California 90024.
- (2) Except as otherwise noted, based on total shares outstanding of 385,631,190 as of February 28, 2015.
- (3) Based on a Schedule 13G filed with the SEC on February 4, 2015 by Occidental. Occidental has sole voting and dispositive power with respect to 71,500,000 shares of common stock. Occidental’s address is 5 Greenway Plaza, Suite 110, Houston, Texas 77046. In accordance with the Stockholder’s and Registration Rights Agreement, Occidental granted us a proxy to vote the shares of our common stock that Occidental retained immediately after the distribution relating to the Spin-off in proportion to the votes cast by our other stockholders.
- (4) Based on a Schedule 13D filed with the SEC on February 2, 2015 by Seis Holdings LLC (“Seis”), C. Park Shaper (“Shaper”), Soroban Capital Partners LP (“SCP LP”), Soroban Master Fund LP (“SMF LP”), Soroban Capital GP LLC (“SCGP LLC”), Soroban Capital Partners GP LLC (“SCPGP LLC”), and Eric W. Mandelblatt (“Mandelblatt”). Seis, Shaper, SCP LP, SMF LP, SCGP LLC, SCPGP LLC and Mandelblatt are deemed to beneficially own 38,469,999 shares of common stock. SCP LP, SCGP LLC, SCPGP LLC and Mandelblatt have shared voting and dispositive power with respect to 34,469,999 shares of common stock. SMF LP has shared voting and dispositive power with respect to 26,847,532 shares of common stock. Seis and Shaper have shared voting and dispositive power with respect to 4,000,000 shares of common stock. SCP LP, SCGP LLC, SCPGP LLC, and Mandelblatt share the address of 444 Madison Avenue, 21st Floor, New York, New York 10022. SMF LP’s address is Gardenia Court, Suite 3307, 45 Market Street, Camana Bay, Grand Cayman KY1-1103, Cayman Islands. Seis and Shaper share the address of 510 Bering Drive, Suite 220, Houston, Texas 77057.
- (5) Based on a Schedule 13G filed with the SEC on February 13, 2015 by Southeastern Asset Management, Inc. (“Southeastern”), Longleaf Partners – Small Cap Fund (“Longleaf”), and Mason Hawkins (“Hawkins”). Southeastern has (i) shared voting and dispositive power with respect to 33,090,500 shares of common stock; (ii) no voting power with respect to 391,000 shares of common stock; and (iii) sole dispositive power with respect to 391,000 shares of common stock. Southeastern’s address is 6410 Poplar Avenue, Suite 900, Memphis, Tennessee 38119.
- (6) Based on a Schedule 13G filed with the SEC on February 13, 2015 by Southeastern, Longleaf and Hawkins. Longleaf has shared voting and dispositive power with respect to 33,090,500 shares of common stock. Longleaf’s address is 6410 Poplar Avenue, Suite 900, Memphis, Tennessee 38119.
- (7) Based on a Schedule 13G filed with the SEC on February 10, 2015 by The Vanguard Group (“Vanguard”). Vanguard has (i) sole voting power with respect to 181,716 shares of common stock, (ii) sole dispositive power with respect to 19,260,106 shares of common stock; and (iii) shared voting and dispositive power with respect to 181,716 shares of common stock. Vanguard’s address is 100 Vanguard Boulevard, Malvern, Pennsylvania 19355.
- (8) Ms. Kehr was appointed to the Board of Directors effective as of March 15, 2015.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

This section discusses other transactions and relationships with related persons during the past three fiscal years. As a subsidiary of Occidental, we engaged in related party transactions with Occidental. Those transactions are described in more detail in the notes to the accompanying

financial statements. In addition, Occidental retained approximately 18.5% of our common stock in connection with the Spin-off. Although it has agreed to vote that stock proportionately to the vote of our other stockholders, transactions with Occidental are still considered related party transactions.

Arrangements Between Occidental and Our Company

This section provides a summary description of agreements that we entered into with Occidental relating to our restructuring transactions and our relationship with Occidental after the Spin-off. This description of the agreements between Occidental and us is a summary and, with respect to each such agreement, is qualified by reference to the terms of the agreement, a copy of each of which is filed as an exhibit to CRC’s Current Report on Form 8-K filed on December 1, 2014, and is incorporated herein by reference.

Separation and Distribution Agreement

The Separation and Distribution Agreement governs the terms of the separation of Occidental’s California oil and gas exploration and production operations and related assets, liabilities and obligations (the “California business”) from Occidental’s other businesses. Generally, the Separation and Distribution Agreement includes the agreements of Occidental and us on the steps taken to complete the separation, including the assets and rights transferred, liabilities assumed or retained, contracts assigned and related matters. The Separation and Distribution Agreement provides for Occidental and us to transfer specified assets and liabilities between the two companies to separate the California business from Occidental’s remaining businesses. As a result of this transfer, we own all assets exclusively related to the California business, including the assets reflected on our balance sheet as of September 30, 2014 other than assets disposed of after such date, and certain other assets related to the California business specifically allocated to us. We are also responsible for all liabilities, including environmental liabilities, to the extent relating to the operation or ownership of the California business or any of the assets allocated to us in the separation, as well as all liabilities arising out of, relating to or resulting from our new financing arrangements or reflected as liabilities on our balance sheet as of September 30, 2014, subject to the discharge of any such liabilities after September 30, 2014. Occidental retained all other assets and liabilities, including assets and liabilities related to discontinued businesses (other than those businesses that were a part of the California business prior to being discontinued). For purposes of allocating assets and liabilities between us and Occidental, the Separation and Distribution Agreement provides that the California business generally means:

- the exploration for and development and production of crude oil and condensate, NGLs and natural gas in the State of California and in state waters offshore California, including all California operations of Occidental’s oil and gas segment;
- the ownership and operation of our power plants at Elk Hills Field and in a portion of the Wilmington Field;
- the marketing and trading of crude oil and condensate, NGL, natural gas, water, steam and electricity produced in the operations described in the prior two bullet points; and
- the abandonment, monitoring and remediation of oil and gas properties and operations utilized therein.

The Separation and Distribution Agreement also provides that the California business does not include the existing third-party gas marketing business of Occidental’s non-California midstream and marketing segment, which participates in various U.S. markets, including California.

Unless otherwise provided in the Separation and Distribution Agreement or any of the related ancillary agreements, all assets were transferred on an “as is, where is” basis.

The Separation and Distribution Agreement required Occidental and us to endeavor to obtain consents, approvals and amendments required to novate or assign the assets and liabilities that are to be transferred pursuant to the Separation and Distribution Agreement as soon as reasonably practicable. Generally, if the transfer of any assets or liabilities required a consent that would not be obtained before the distribution, or if any assets or liabilities were erroneously transferred or if any assets or liabilities were erroneously not transferred, each party agreed to hold the relevant assets or liabilities for the intended party’s use and benefit (at the intended party’s expense) until they could be transferred to the intended party.

The Separation and Distribution Agreement also governs the treatment of all aspects relating to indemnification and insurance, and generally provides for cross-indemnities principally designed to place financial responsibility for the obligations and liabilities of our business with us and financial responsibility for the obligations and liabilities of the remaining Occidental business with Occidental. The Separation and Distribution Agreement also established procedures for handling claims subject to indemnification and related matters. We and Occidental generally released each other from all claims arising prior to the Spin-off other than claims arising under the transaction agreements, including the indemnification provisions described above.

Transition Services Agreement

The Transition Services Agreement sets forth the terms on which Occidental will provide to us, and we will provide to Occidental, on an as-needed basis for 12 to 18 months from the Spin-off, certain services or functions that the companies historically have shared.

Tax Sharing Agreement

The Tax Sharing Agreement governs the respective rights, responsibilities, and obligations of Occidental and us with respect to tax liabilities and benefits, tax attributes, the preparation and filing of tax returns, the control of audits and other tax proceedings, and other matters regarding taxes. The Tax Sharing Agreement will remain in effect until the parties agree in writing to its termination; however, notwithstanding such termination, the Tax Sharing Agreement will remain in effect with respect to any payments or indemnification due for all taxable periods prior to such termination during which the agreement was in effect.

In general, pursuant to the Tax Sharing Agreement:

- CRC and Occidental agreed to cooperate in the preparation of tax returns, refund claims and with regard to audits concerning matters covered by the agreement;
- the Tax Sharing Agreement assigns responsibilities for administrative matters, such as the filing of tax returns, payment of taxes due, retention of records and conduct of audits, examinations, or similar proceedings;
- with respect to any periods (or portions thereof) ending prior to the distribution and periods that begin on or before but end after the distribution, Occidental will pay any U.S. federal income taxes of the affiliated group of which Occidental is the common parent and, if CRC (including any of its subsidiaries) is included in that affiliated group, CRC will pay Occidental an amount equal to the amount of additional U.S. federal income taxes payable by Occidental resulting from Occidental's election to capitalize some or all of certain CRC intangible drilling costs. Occidental has sole discretion to make the election but will likely elect to capitalize intangible drilling costs only to the extent that higher CRC taxable income is needed to ensure that distributions paid by CRC to Occidental or its subsidiaries are not taxable. CRC will also be responsible for any increase in Occidental's federal tax liability for any period in which CRC or any CRC subsidiaries are combined or consolidated with Occidental if such increase results from audit adjustments attributable to CRC's business. With respect to any periods (or portions thereof) beginning after the distribution, CRC will be responsible for any U.S. federal income taxes of CRC and its subsidiaries;
- with respect to any periods (or portions thereof) ending prior to the distribution and periods that begin on or before but end after the distribution, Occidental will pay any state or local franchise or income taxes that

are determined on a consolidated, combined, or unitary basis and, if CRC (including any of its subsidiaries) is included in such determination, CRC will pay Occidental an amount equal to the amount of additional taxes payable by Occidental resulting from Occidental's election to capitalize some or all of certain CRC intangible drilling costs. CRC will also be responsible for any increase in Occidental's state tax liability for any period in which CRC or any CRC subsidiaries are combined or consolidated with Occidental if such increase results from audit adjustments attributable to CRC's business;

- with respect to any periods (or portions thereof) beginning after the distribution, CRC will be responsible for any U.S. federal, state or local income taxes of CRC and its subsidiaries;
- Occidental will be responsible for any U.S. federal, state, local, or foreign taxes due with respect to tax returns that include only Occidental and/or its subsidiaries (excluding CRC and its subsidiaries), and CRC will be responsible for any U.S. federal, state, local or foreign taxes due with respect to tax returns that include only CRC and/or its subsidiaries;
- to the extent that any gain or income is recognized by Occidental (including its subsidiaries) in connection with the failure of the Spin-off or certain transactions undertaken in preparation for, or in connection with, the Spin-off, to qualify for tax-free treatment under the relevant provisions of the Code, CRC will indemnify Occidental for any taxes on such gain or income to the extent such failure is attributable to:
 - inaccurate covenants, representations, or warranties by CRC (or any CRC subsidiaries) made in connection with the Tax Sharing Agreement or any tax ruling requested or received from the IRS or opinions of Occidental's outside tax advisors;
 - any breach by CRC (or any CRC subsidiaries) of certain restrictive covenants in the Tax Sharing Agreement; or
 - certain other actions taken by CRC; and
- CRC will bear 50% of the amount of any taxes resulting from gain or income that is recognized by Occidental (including its subsidiaries)

in connection with the failure of the Spin-off or a related transaction to qualify for tax-free treatment under the relevant provisions of the Code, to the extent such failure is not attributable to the fault of either party; however, if CRC receives an increase in the tax basis of its depletable, depreciable or amortizable assets as a result of any such tax being imposed, CRC will pay to Occidental an amount equal to any reduction in its tax liability attributable to such basis increase when such reduction in tax liability arises.

Occidental received a private letter ruling from the IRS substantially to the effect that certain aspects of the transactions that were undertaken in preparation for, or in connection with, the Spin-off will not cause the distribution to be taxable to Occidental or its affiliates for federal income tax purposes.

CRC agreed to certain restrictions intended to preserve the tax-free status of certain transactions related to the Spin-off. During the two-year period following Occidental's disposition of the Securities retained by it in the Spin-off, these covenants restrict CRC's ability to: (a) voluntarily liquidate or dissolve; (b) merge, convert or consolidate with or into another entity; (c) issue any capital stock or other equity interests, options or rights to acquire capital stock or other equity interests, or any other instruments convertible into or exchangeable for, or that could otherwise result in the issuance of, capital stock or other equity interests; (d) redeem or otherwise repurchase any outstanding capital stock or other equity interests, rights or instruments, other than pursuant to open market stock repurchase programs meeting certain requirements; (e) recapitalize, reclassify, or alter the voting rights of one or more shares of capital stock or other equity interests, rights or instruments; (f) take certain other actions inconsistent with any representation made in any materials provided in connection with any private letter ruling request or opinions of Occidental's outside tax advisors; (g) increase or decrease the number of members of the board of directors of CRC or any pre-Spin-off CRC subsidiary, alter in any way the procedures for the nomination, election, and termination of members of the board, or expand, contract, or otherwise modify the rights of the board to govern the affairs of CRC except in certain circumstances; (h) sell, exchange, distribute, or otherwise dispose of any pre-Spin-off CRC

subsidiary or all or a substantial part of the assets of any of the trades or businesses conducted by CRC and the pre-Spin-off CRC subsidiaries (other than sales or transfers of inventory in the ordinary course of business) before the Spin-off except in certain circumstances; (i) take, or fail to take, any action that causes the trades or businesses conducted by CRC or any pre-Spin-off CRC subsidiary to cease to be actively conducted in substantially the manner conducted pre-Spin-off; (j) sell, transfer or agree to sell or transfer to any corporate subsidiary any assets held by certain Occidental subsidiaries before Occidental's internal reorganization in connection with the Spin-off; (k) enter into any negotiations, agreements, understandings, or arrangements with respect to any of the foregoing; and (l) take, or fail to take, any action that could reasonably be expected to cause the Spin-off to fail to qualify as a tax-free transaction under Sections 355, 361 and/or 368(a)(1)(D) of the Code. CRC may take certain actions otherwise subject to these restrictions only if Occidental consents to the taking of such action or if CRC obtains, and provides to Occidental, a private letter ruling from the IRS and/or an opinion from an independent law firm or accounting firm, in either case, reasonably acceptable to Occidental, to the effect that such action would not jeopardize the tax-free status of certain transactions related to the Spin-off.

Employee Matters Agreement

The Employee Matters Agreement governs Occidental's and our compensation and employee benefit obligations with respect to the current and former employees of each company, and generally allocates liabilities and responsibilities relating to employee compensation and benefit plans and programs. The Employee Matters Agreement provides for the following:

- the transfer of all employees who, following the Spin-off, work for the California business ("transferred employees") to us or one of our subsidiaries;
- the assumption (or retention) by us and our subsidiaries of all liabilities and obligations relating to current and former employees of the California business (excluding, with respect to current employees, certain pension obligations and, with respect to former employees, certain pension, retiree medical and nonqualified deferred compensation plan obligations);
- the retention by Occidental of all employee and benefit plan-related liabilities and obligations not relating to current or former employees of the California business;
- the establishment by us and our subsidiaries of new employee benefit plans for purposes of providing benefits to transferred employees;
- the cessation of active participation by transferred employees under all benefit plans sponsored by Occidental;
- the conversion of Occidental equity and equity-based awards held by transferred employees into awards with respect to our common stock;
- the adjustment of Occidental equity and equity-based awards not held by transferred employees to reflect the effect of the Spin-off;
- the transfer of all assets held in trusts maintained by Occidental which relate to benefits payable under certain defined benefit plans

maintained by our subsidiaries to a trust (or trusts) maintained by the respective subsidiaries;

- the transfer of liabilities and other obligations relating to benefits accrued by transferred employees pursuant to Occidental’s supplemental retirement and nonqualified deferred compensation plans from Occidental to us and our subsidiaries;
- that the Spin-off is not intended to constitute a “change in control” or similar transaction under Occidental or our benefit and compensation plans;

- the crediting of transferred employees for their service with Occidental for purposes of determining eligibility, vesting and benefit levels under our benefit plans; and
- general cooperation and sharing of information between us and Occidental on matters relating to the transfers of employees and employee benefit plan-related liabilities and obligations.

AMI Agreement

The Area of Mutual Interest ("AMI") Agreement has a five-year term and sets forth the terms upon which Occidental may acquire an interest in and rights with respect to certain oil and gas properties (the “AMI Interests”) in the United States (excluding California and federal waters offshore California) (the “AMI Area”). Pursuant to the terms of the AMI Agreement, for a period of one year after notice from us, Occidental may elect to exercise an option to acquire an interest in the AMI Interests. Upon exercise, Occidental will acquire an undivided 51% interest in the subject AMI Interests for consideration equal to the sum of (i) 51% of the net acquisition price paid by us for such AMI Interests and (ii) 51% of the drilling and/or operating costs paid by us (net of any reimbursements) in respect of such AMI Interests attributable to any periods after the date of our acquisition of such AMI Interests, and less (iii) 51% of the revenue attributable to such AMI Interests after the date of our acquisition of such AMI Interests, subject to certain limited exceptions. If applicable, in connection with the exercise of Occidental’s option, we will resign as operator and vote for Occidental or its designee as the replacement operator.

Confidentiality and Trade Secret Protection Agreement

Pursuant to the Confidentiality and Trade Secret Protection Agreement, we agreed to keep confidential certain information we learned about Occidental prior to the Spin-off. In order to preserve Occidental’s trade secrets and confidential information and to protect the goodwill transferred to us in connection with the Spin-off, among other things, CRC and Occidental agreed (i) not to hire the other party’s employees for a period of one year following the completion of the Spin-off and (ii) not to solicit the other party’s employees for an additional four years following the expiration of the non-hire restrictions.

Intellectual Property License Agreement

The Intellectual Property License Agreement sets forth the terms on which Occidental, on behalf of itself and its affiliates, licensed certain intellectual property and documentation to us and our affiliates, including software owned by Occidental and its affiliates. We have the right to create derivative works of the software and documentation and use them for our internal business purposes. The Intellectual Property License Agreement also sets forth the terms on which we licensed Occidental and its affiliates certain data and documentation. Occidental and its affiliates have the right to create derivative works of such data and documentation and use them for their internal business purposes.

Stockholder’s and Registration Rights Agreement

Prior to the distribution, we and Occidental entered into a Stockholder’s and Registration Rights Agreement pursuant to which we agreed that, upon the request of Occidental, we will use our reasonable best efforts to effect the registration under applicable federal and state securities laws of the disposition of shares of our common stock retained by Occidental after the distribution and to cooperate with Occidental to facilitate its disposition of the Retained Securities through one or more exchanges for Occidental common stock. In addition, we agreed to certain restrictions on our ability to file registration statements during any exchange offer or grant registration rights to third parties during the term of the Stockholder’s and Registration Rights Agreement. Occidental also granted us a proxy to vote the shares of our common stock that Occidental retained immediately after the distribution in proportion to the votes cast by our other stockholders. This proxy, however, will be automatically revoked as to a particular share upon any transfer of such share from Occidental to a person other than Occidental, and neither the voting agreement nor the proxy will limit or prohibit any transfer.

Other Related Party Transactions

In addition to the related party transactions described in “Arrangements Between Occidental and Our Company” above, this section discusses other transactions and relationships with related persons since the beginning of our most recently completed fiscal year.

Marketing Transactions

Substantially all of our marketing of oil, gas and NGLs had historically been transacted through Occidental’s marketing subsidiaries. For the years ended December 31, 2014, 2013 and 2012, sales through Occidental’s marketing subsidiaries accounted for approximately \$2.7 billion, \$4.2 billion and \$4.0 billion of our net sales respectively.

In August 2014, we began to market products through a wholly owned marketing subsidiary and, through January 31, 2015, we entered into contracts for approximately \$70 million in net sales with subsidiaries of Plains All American Pipeline, L.P. (“Plains”). In addition we have a ship-or-pay agreement with Plains that provides us with capacity to transport 10,000 barrels per day of NGLs starting the second quarter of 2015. Occidental owns approximately 13% of the general partner of Plains. Funds managed by Kayne Anderson Capital Advisors L.P. and affiliates (“Kayne Anderson”) own approximately 20% of the general partner of Plains, approximately 3.4% of the limited partner units of Plains and an additional approximately 4.5% general partner interest in Plains GP Holdings, L.P. (the public portion of the general partner). Occidental appoints a director, and Robert V. Sinnott also serves as a director, for the general partner of Plains and Mr. Sinnott also serves as a director for Plains.

Transactions with Related Persons, Promoters and Certain Control Persons

Certain funds controlled by Kayne Anderson Investment Management, Inc., of which Mr. Sinnott serves as President, purchased, and subsequently sold, \$5 million in aggregate principal amount of our 6% senior notes due 2024.

Wells Fargo & Company, of which Mr. Sloan currently serves as Senior Executive Vice President Wholesale Banking, or its affiliates (“Wells”) acted as a Joint Book-Running Manager for, and initial purchaser of approximately \$430 million in aggregate principal amount of, the notes. Wells currently holds none of the notes. Wells is acting as trustee under the indenture and as the exchange agent under this exchange offer, and as a lender and Documentation Agent under our Revolving Credit Facility and Term Loan Facility. Wells’ portion of the total commitments, and maximum aggregate principal amount outstanding in 2014, under our Revolving Credit Facility and Term Loan collectively was approximately \$235 million and \$114 million, respectively. As of February 9, 2015, Wells’ portion of the amount outstanding under the Revolving Credit Facility is \$38 million. Wells received interest of approximately \$210,000 under the Revolving Credit Facility and Term Loan in 2014 at interest rates varying between 2.15% and 4.25%.

Policies and Procedures with respect to Related Party Transactions and Conflicts of Interest

Our Board of Directors adopted policies restricting related party transactions. We review all relationships and transactions in which we and our directors and executive officers or their immediate family members are participants to determine whether such persons have a direct or indirect material interest. Our Corporate Secretary’s office implements procedures to obtain information from the directors and executive officers with respect to related party transactions. Determinations as to whether an executive officer or director has a direct or indirect material interest and whether such an interest is permissible are determined by the Audit Committee of our Board of Directors. Agreements that embody transactions that are material in amount or significance are filed with the SEC as required.

Our business ethics and corporate policies prohibit significant conflicts of interest. Any waivers of these policies require approval by a compliance officer, the corporate compliance committee or uninvolved members of the Audit Committee (in the case of conflicts of our executive officers or directors). Under our business ethics and corporate policies, conflicts of interest generally are deemed to occur when private or family interests interfere or compete with the interests of our Company.

We have multiple processes for reporting conflicts of interests, including related party transactions. Under the business ethics and corporate policies, all our directors and employees are required to report any known or apparent conflict of interest, or potential conflict of interest, to their supervisors, a compliance officer, the corporate compliance committee or the Audit Committee as appropriate. As part of any review, the following factors are generally considered:

- The nature of the related person’s interest in the transaction;
- The material terms of the transaction;

- The importance of the transaction to the related person;
- The importance of the transaction to us;
- Whether the transaction would impair the judgment of a director or executive officer to act or their ability to act in our best interest;
- Whether the transaction might affect a director’s independence under NYSE standards; and
- Any other matters deemed appropriate with respect to the particular transaction.

We also have other policies and procedures to prevent conflicts of interest, including related person transactions. For example, the charter of our Nominating and Governance Committee requires that the committee members assess the independence of the non-management directors at least annually, including a requirement that it determine whether any such directors have a material relationship with us, either directly or indirectly, as defined therein and as further described above under “Management—Board of Directors—Director Independence.”

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
COMPUTATION OF TOTAL ENTERPRISE RATIO OF EARNINGS TO FIXED CHARGES
(Amounts in millions, except ratios)

The following table sets forth historical ratios of earnings to fixed charges for the periods indicated. You should read these ratios of earnings to fixed charges in connection with our consolidated and combined financial statements, including the notes to those statements.

	Year Ended December 31,				
	2014	2013	2012	2011	2010
Income / (loss) before income taxes ^(a)	\$ (2,421)	\$ 1,447	\$ 1,181	\$ 1,641	\$ 1,129
Add:					
Interest expense and amortization of debt issuance costs	72	—	—	—	—
Portion of lease rentals representative of the interest factor	3	4	4	3	3
Earnings before fixed charges	\$ (2,346)	\$ 1,451	\$ 1,185	\$ 1,644	\$ 1,132
Fixed charges:					
Interest expense and amortization of debt issuance costs, including capitalized interest	\$ 76	\$ —	\$ —	\$ —	\$ —
Portion of lease rentals representative of the interest factor	3	4	4	3	3
Total fixed charges	\$ 79	\$ 4	\$ 4	\$ 3	\$ 3
Ratio of earnings to fixed charges ^(b)	n/a	363	296	548	377
Insufficient coverage	\$ 2,425	\$ —	\$ —	\$ —	\$ —

Note: Had we been a stand-alone company for the full year 2014, and had the same level of debt throughout the year as we did on December 31, 2014, of approximately \$6.4 billion, we would have incurred \$314 million of pre-tax interest expense, on a pro-forma basis, for the year ended December 31, 2014, compared to the \$72 million pre-tax interest expense reported on our statement of operations for the year then ended. Therefore, the insufficient coverage on a pro-forma basis would have been approximately \$2,437 million.

- (a) The 2014 amount includes non-cash charges consisting of \$3.4 billion of asset impairments, \$52 million of rig termination and other price-related costs, and \$55 million of Spin-off and transition related costs. Excluding these items, our income before income taxes for the year ended December 31, 2014 would have been approximately \$1.1 billion, and the ratio of earnings to fixed charges would have been 14.
- (b) The 2014 ratio takes into consideration interest on the debt associated with the Spin-off which we entered into during the last half of 2014.

DESCRIPTION OF EXCHANGE NOTES

California Resources Corporation issued the original notes, and will issue the exchange notes, under an indenture (the “*Indenture*”), dated October 1, 2014, among CRC, as issuer, the initial Guarantors (as defined below), as guarantors, and Wells Fargo Bank, National Association, as trustee (the “*Trustee*”). The terms of the exchange notes include those stated in the Indenture and those made part of the Indenture by reference to the Trust Indenture Act of 1939, as amended (the “*Trust Indenture Act*”).

The following description is only a summary of certain material provisions of the exchange notes and the Indenture and is subject to, and is qualified in its entirety by reference to, the exchange notes and the Indenture. For more information, we refer you to the exchange notes and the Indenture, of which you may request copies at our address set forth under the heading “Where You Can Find More Information.” Defined terms used but not otherwise defined in this section shall have the meanings assigned to such terms in the Indenture.

In this “Description of Exchange Notes,” the words “CRC,” “Company,” “our,” “us” and “we” refer only to California Resources Corporation and not to any of its subsidiaries. Any reference to the “exchange notes” contained in this description collectively refers to the registered 5% Senior Notes due 2020 (the “2020 exchange notes”), 5½% Senior Notes due 2021(the “2021 exchange notes”) and 6% Senior Notes due 2024 (the “2024 exchange notes”), unless the context indicates otherwise. Any reference to the “notes” or “Notes” contained in this description collectively refers to the exchange notes and the unregistered 5% Senior Notes due 2020 (the “2020 original notes”), 5½% Senior Notes due 2021(the “2021 original notes”) and 6% Senior Notes due 2024 (the “2024 original notes”), unless the context indicates otherwise.

General

On October 1, 2014, CRC issued \$5.0 billion in aggregate principal amount of original notes in three separate series under the Indenture. The exchange notes will be general unsecured senior obligations of CRC and will be guaranteed by the Guarantors on a senior unsecured basis as described below under “—Guarantees.” The exchange notes will rank *pari passu* in right of payment with all existing and future senior unsecured indebtedness of CRC, including the original notes, and rank senior in right of payment to all future subordinated Indebtedness of CRC.

The 2020 exchange notes will mature on January 15, 2020, the 2021 exchange notes will mature on September 15, 2021, and the 2024 exchange notes will mature on November 15, 2024. The exchange notes and any additional notes will be issued in denominations of \$2,000 or integral multiples of \$1,000 in excess thereof.

Interest on the exchange notes will accrue from October 1, 2014 at an annual rate of 5% in the case of the 2020 exchange notes, 5 ½% in the case of the 2021 exchange notes and 6% in the case of the 2024 exchange notes. Interest on the 2020 exchange notes will be payable semi-annually in arrears on January 15 and July 15 of each year, commencing on July 15, 2015, to the Holders of record of such exchange notes at the close of business on each January 1 and July 1, respectively, preceding such interest payment date. Interest on the 2021 exchange notes will be payable semi-annually in arrears on March 15 and September 15 of each year, commencing on March 15, 2015, to the Holders of record of such exchange notes at the close of business on each March 1 and September 1, respectively, preceding such interest payment date. Interest on the 2024 exchange notes will be payable semi-annually in arrears on May 15 and November 15 of each year, commencing on May 15, 2015, to the Holders of record of such exchange notes at the close of business on each May 1 and November 1, respectively, preceding such interest payment date. Interest will be computed on the basis of a 360-day year consisting of twelve 30-day months. Initially, the Trustee will act as paying agent and registrar for the exchange notes.

Further Issuances

We may from time to time, without notice or the consent of the Holders of the exchange notes, issue additional notes of any series having the same terms as the existing notes of such series (except for interest accrual dates, issue prices and terms relating to restrictions on transfer or registration rights). Any such additional notes will form a single series with the existing notes of such series and have the same terms as to status, redemption or otherwise as the applicable existing series of notes; *provided, however*, if the additional notes are not fungible with the

applicable existing series of notes for U.S. federal income tax purposes, such additional notes will have a different CUSIP number.

Optional Redemption

2020 Exchange Notes

At any time prior to December 15, 2019, we may redeem the 2020 exchange notes, in whole or in part, at a redemption price equal to the Make-Whole Price, plus accrued and unpaid interest, if any, to, but excluding, the redemption date.

At any time on or after December 15, 2019, we may redeem the 2020 exchange notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the 2020 exchange notes being redeemed, plus accrued and unpaid interest, if any, to, but excluding, the redemption date.

2021 Exchange Notes

At any time prior to June 15, 2021, we may redeem the 2021 exchange notes, in whole or in part, at a redemption price equal to the Make-Whole Price, plus accrued and unpaid interest, if any, to, but excluding, the redemption date.

At any time on or after June 15, 2021, we may redeem the 2021 exchange notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the 2021 exchange notes being redeemed, plus accrued and unpaid interest, if any, to, but excluding, the redemption date.

2024 Exchange Notes

At any time prior to August 15, 2024, we may redeem the 2024 exchange notes, in whole or in part, at a redemption price equal to the Make-Whole Price, plus accrued and unpaid interest, if any, to, but excluding, the redemption date.

At any time on or after August 15, 2024, we may redeem the 2024 exchange notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the 2024 exchange notes being redeemed, plus accrued and unpaid interest, if any, to, but excluding, the redemption date.

With respect to any redemption of certificated exchange notes with a redemption date after an interest payment record date but before the succeeding interest payment date, interest will be paid to the Holder of record as of the record date and will not be included in the redemption price.

Notice and Selection

Notice of optional redemption of the exchange notes must be given to each Holder of the relevant series of the exchange notes not less than 30 nor more than 60 days prior to the redemption date in accordance with the Indenture; provided that in connection with a defeasance or satisfaction and discharge notice may be given more than 60 days prior to the redemption date.

Once a notice of redemption is given in accordance with the Indenture, exchange notes called for redemption become due and payable on the applicable redemption date at the applicable redemption price. Any notice of redemption for the exchange notes will state, among other things, the aggregate principal amount and the exchange notes to be redeemed, the redemption date and the name and address of the paying agent. If less than all of the exchange notes are redeemed at any time, the Trustee will select the exchange notes to be redeemed on a pro rata basis, by lot or in accordance with any other method the Trustee deems fair and appropriate, subject to the Depositary's procedures, or, if the exchange notes are listed on any securities exchange, by any other method that complies with the requirements of such exchange; *provided, however*, that no exchange notes with a principal amount of \$2,000 or less will be redeemed in part. Unless we default in payment of the applicable redemption price,

interest on the exchange notes to be redeemed will cease to accrue on the applicable redemption date, whether or not such exchange notes are presented for payment.

Certain Definitions

“*Make-Whole Amount*” with respect to an exchange note of a series means an amount equal to any excess of (i) the present value of the remaining principal and interest payments due on such exchange note (excluding any portion of such payments of interest accrued as of the redemption date) through the Maturity Date of such exchange notes, computed using a discount rate equal to the Treasury Rate plus 50 basis points over (ii) the outstanding principal amount of such exchange note. Calculation of the Make-Whole Amount will be made by the Company or on behalf of the Company by such Person as the Company shall designate; *provided, however*, that such calculation shall not be a duty or obligation of the Trustee.

“*Make-Whole Remaining Life*” means the number of years (calculated to the nearest one-twelfth) between the date of redemption and the Maturity Date applicable to the relevant series of the exchange notes being redeemed.

“*Make-Whole Price*” means the sum of the outstanding principal amount of the exchange notes to be redeemed plus the Make-Whole Amount of such exchange notes.

“*Treasury Rate*” means the yield to maturity (calculated on a semi-annual bond equivalent basis) at the time of the computation of United States Treasury securities with a constant maturity (as compiled by and published in the most recent Federal Reserve Statistical Release H.15 (519) or any successor publication which is published weekly by the Board of Governors of the Federal Reserve System and which establishes yields on actively traded United States Treasury securities adjusted to constant maturity under the caption “Treasury Constant Maturities”), which has become publicly available at least two Business Days prior to the date of the redemption notice (or, if such Federal Reserve Statistical Release is no longer published, any publicly available source of similar market data) most nearly equal to the then remaining maturity of the relevant series of the exchange notes being redeemed; *provided, however*, that if the Make-Whole Remaining Life of such exchange notes is not equal to the constant maturity of the United States Treasury security for which a weekly average yield is given, the Treasury Rate shall be obtained by linear interpolation or extrapolation (calculated to the nearest one-twelfth of a year) from the weekly average yields of United States Treasury securities for which such yields are given, except that if the Make-Whole Remaining Life of such exchange notes is less than one year, the weekly average yield on actually traded United States Treasury securities adjusted to a constant maturity of one year shall be used.

“*Business Day*” means any day other than a Saturday, a Sunday or a day on which banks and trust companies in the City of New York or any other place of payment with respect to the exchange notes are not required by law or executive order to be open.

Guarantees

Payment of the principal, premium, if any, and interest on the exchange notes, when and as the same becomes due and payable, will be guaranteed, jointly and severally, on a senior unsecured basis (the “Guarantees”) by the Guarantors. Initially, all of our Subsidiaries, other than certain immaterial Subsidiaries, will be Guarantors. In the circumstances described under “—Certain Covenants—Future Guarantees,” we may also be required to cause certain of our future Restricted Subsidiaries to become Guarantors.

The obligations of each Guarantor under its Guarantee will be limited to the maximum amount which, after giving effect to all other contingent and fixed liabilities of such Guarantor, and after giving effect to any collections from or payments made by or on behalf of any other Guarantor in respect of the obligations of such other Guarantor under its Guarantee or pursuant to its contribution obligations under the Indenture, will result in the obligations of such Guarantor under its Guarantee not constituting a fraudulent conveyance or fraudulent transfer under federal or state law. See “Risk Factors—Risks Related to the Exchange Notes.” Each Guarantor that makes a payment or distribution under its Guarantee will be entitled to seek contribution from each other Guarantor in a pro rata amount based on the net assets of each Guarantor determined in accordance with GAAP.

The Guarantee of a Guarantor will be released automatically with respect to the exchange notes:

- (A) in connection with any sale or other disposition of (i) Capital Stock of such Guarantor such that after such sale or disposition the Guarantor is no longer a Subsidiary of the Company or (ii) all or substantially all of the properties or assets of such Guarantor (including by way of merger or consolidation), in each case to one or more Persons that are not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary;
- (B) if the Guarantor ceases to provide a guarantee with respect to Indebtedness of the Company under the Credit Agreement;
- (C) if the exchange notes are defeased or discharged in accordance with the procedures described below under “—Legal Defeasance and Covenant Defeasance” or “—Satisfaction and Discharge;” or
- (D) upon the liquidation or dissolution of such Guarantor.

Ranking

The Indebtedness evidenced by the exchange notes and the Guarantees will be unsecured and will rank *pari passu* in right of payment with all senior indebtedness of the Company and the Guarantors, respectively, including the original notes and borrowings and guarantees under the Credit Agreement.

As of December 31, 2014, we and our subsidiaries had approximately \$6.36 billion of consolidated indebtedness, comprised of \$5.0 billion of original notes, \$1.0 billion of borrowings outstanding under our Term Loan Facility and \$360 million of borrowings outstanding under our Revolving Credit Facility. We currently have the ability to incur total net borrowings of up to \$1.25 billion under our Revolving Credit Facility. In addition, as of December 31, 2014 we had letters of credit in an aggregate amount of \$25 million that were issued to support ordinary course marketing, regulatory and other matters under uncommitted letter of credit lines.

The Notes and the Guarantees will effectively rank junior to any future secured indebtedness of the Company or the Guarantors, respectively, to the extent of the value of the collateral therefor. As of December 31, 2014, the Company and the Guarantors had no secured indebtedness outstanding. Under the terms of the Credit Agreement, we will be required to provide collateral for the Credit Facilities if our corporate credit

rating with S&P or our corporate family rating with Moody's falls below certain levels. The Notes and Guarantees would rank senior in right of payment to any future subordinated indebtedness issued by the Company or the Guarantors.

The assets of any existing or future Subsidiary of the Company that does not guarantee the Notes will be subject to the prior claims of all creditors of that Subsidiary, including trade creditors. In the event of a bankruptcy, administrative receivership, composition, insolvency, liquidation or reorganization of any of the non-guarantor Subsidiaries, such Subsidiaries will pay the holders of their liabilities, including trade payables, before they will be able to distribute any of their assets to the Company or a Guarantor. Non-guarantor subsidiaries represented less than 1% of our total assets and had no indebtedness as of December 31, 2014, and represented less than 1% of revenues for the twelve months ended December 31, 2014.

Change of Control

If a Change of Control Triggering Event (which includes a Rating Decline) occurs with respect to a series of exchange notes, each Holder of exchange notes of such series will have the right to require that the Company purchase all or any part (in amounts of \$1,000 or whole multiples of \$1,000 in excess thereof) of such Holder's exchange notes pursuant to the offer described below (the "Change of Control Offer"). In the Change of Control Offer, the Company will offer to purchase all of the exchange notes of such series, at a purchase price (the "Change of Control Purchase Price") in cash in an amount equal to 101% of the principal amount of such exchange notes, plus accrued and unpaid interest, if any, to the date of purchase (the "Change of Control Purchase Date").

Not later than 30 days after the date upon which any Change of Control Triggering Event occurred with respect to a series of exchange notes, or, at the Company's option, prior to a Change of Control but after it is publicly

announced, the Company must notify the Trustee in writing and give notice of either such event to each Holder of exchange notes of such series at such Holder's address appearing in the security register or otherwise deliver notice in accordance with the applicable procedures of the Depositary. The notice must state, among other things:

- that a Change of Control Triggering Event has occurred or is expected to occur and the date or expected date of such event;
- the circumstances and relevant facts regarding such Change of Control Triggering Event;
- the Change of Control Purchase Price and the Change of Control Purchase Date, which shall be fixed by the Company on a Business Day no earlier than 30 days nor later than 60 days from the date the notice is mailed or otherwise delivered, or such later date as is necessary to comply with requirements under the Exchange Act; *provided* that the Change of Control Purchase Date may not occur prior to the Change of Control Triggering Event and such notice may be contingent on the occurrence of the Change of Control Triggering Event;
- that any Note not tendered will continue to accrue interest;
- that, unless the Company defaults in the payment of the Change of Control Purchase Price, any exchange notes accepted for payment pursuant to the Change of Control Offer shall cease to accrue interest after the Change of Control Purchase Date; and
- other procedures that a Holder of exchange notes must follow to accept a Change of Control Offer or to withdraw acceptance of the Change of Control Offer.

If a Change of Control Offer is made with respect to a series of exchange notes, the Company may not have available funds sufficient to pay the Change of Control Purchase Price for all of the exchange notes of such series that might be delivered by Holders of the exchange notes seeking to accept the Change of Control Offer. The failure of the Company to make or consummate the Change of Control Offer or pay the Change of Control Purchase Price when due will give the Trustee and the Holders of the exchange notes the rights described under "—Events of Default."

The Credit Agreement provides that the occurrence of certain change of control events with respect to the Company would constitute a default thereunder, which would permit the lenders under the Credit Agreement to accelerate the maturity of such indebtedness. If such acceleration occurred, then the Company would be obligated to repay amounts outstanding under such indebtedness. Any future credit agreements or agreements relating to other indebtedness to which the Company becomes a party may contain similar provisions. No assurance can be given that the Company would have sufficient funds to repurchase all exchange notes and other indebtedness that may be required to be repaid in the event of a Change of Control Triggering Event.

The definition of Change of Control includes a phrase relating to the sale, lease, transfer, conveyance or other disposition of "all or substantially all" of the assets of the Company. The term "all or substantially all" as used in the definition of "Change of Control" has not been interpreted under New York law (which is the governing law of the Indenture) to represent a specific quantitative test. Therefore, if Holders of the

exchange notes elected to exercise their rights under the Indenture and the Company elected to contest such election, it is not clear how a court interpreting New York law would interpret the phrase.

The existence of a Holder’s right to require the Company to repurchase such Holder’s exchange notes upon a Change of Control Triggering Event may deter a third party from acquiring the Company in a transaction which constitutes a Change of Control.

The provisions of the Indenture do not afford Holders of the exchange notes the right to require the Company to repurchase the exchange notes in the event of a highly leveraged transaction or certain transactions with the Company’s management or its Affiliates, including a reorganization, restructuring, merger or similar transaction (including, in certain circumstances, an acquisition of the Company by management or its Affiliates) involving the

Company that may adversely affect Holders of the exchange notes, if such transaction is not a transaction defined as a Change of Control Triggering Event.

The Company will comply with the applicable tender offer rules, including Rule 14e-1 under the Exchange Act, and any other applicable securities laws or regulations in connection with a Change of Control Offer. To the extent that the provisions of any securities laws or regulations conflict with the provisions relating to a Change of Control Offer, the Company will comply with the applicable securities laws and regulations and will not be deemed to have breached its obligations described above by virtue thereof.

The Company will not be required to make a Change of Control Offer (1) if a third party makes the Change of Control Offer in the manner, at the times and otherwise in compliance with the requirements described in the Indenture applicable to a Change of Control Offer made by the Company and purchases all Notes validly tendered and not withdrawn under such Change of Control Offer or (2) if notice of redemption for 100% of the aggregate principal amount of the outstanding Notes has been given pursuant to the Indenture as described under the caption “—Optional Redemption,” unless and until there is a default in payment of the applicable redemption price.

In the event that Holders of not less than 90% of the aggregate principal amount of the outstanding Notes of the relevant series accept a Change of Control Offer and the Company purchases all of the Notes held by such Holders, the Company will have the right, upon not less than 30 nor more than 60 days’ prior notice, given not more than 30 days following the purchase pursuant to the Change of Control Offer described above, to redeem all of the Notes of such series that remain outstanding following such purchase at a redemption price equal to 101% of the aggregate principal amount of Notes redeemed plus accrued and unpaid interest, if any, thereon to the date of redemption.

Certain Covenants

Limitation on Liens Securing Funded Debt. The Company will not, and will not permit any Restricted Subsidiary to, create, incur or assume any Funded Debt secured by any Liens (other than Permitted Liens) upon any Property of the Company or any Restricted Subsidiary or upon the Capital Stock of any Restricted Subsidiary unless the Notes or the Guarantee, if any, of such Restricted Subsidiary, as applicable, (together with, if the Company shall so determine, any other Indebtedness or other obligation of the Company or such Restricted Subsidiary) are equally and ratably secured for so long as such Funded Debt shall be so secured; *provided* that if such Funded Debt or other obligation is expressly subordinated to the Notes or a related Guarantee, if any, the Lien securing such Funded Debt or other obligation will be subordinated and junior to the Lien securing such Notes or such Guarantee.

Notwithstanding the foregoing provisions, the Company or any Restricted Subsidiary may create, incur or assume Funded Debt secured by Liens which would otherwise be subject to the restrictions of this covenant, if the aggregate principal amount of such Funded Debt and all other secured Funded Debt of the Company and any Restricted Subsidiary theretofore created, incurred or assumed pursuant to the exception in this sentence and outstanding at such time does not exceed 15% of the Adjusted Consolidated Net Tangible Assets of the Company.

Future Guarantees. The Company will cause each Restricted Subsidiary (other than a Guarantor) that guarantees Indebtedness of the Company under the Credit Agreement, within 90 days of such guarantee, to execute and deliver to the Trustee a supplement to the Indenture under which such Restricted Subsidiary will become a Guarantor of the Notes on the terms, and subject to the release and other provisions, described above under “—Guarantees.”

Limitations on Mergers and Consolidations. The Company will not consolidate or merge with or into any Person, or sell, convey, lease or otherwise dispose of all or substantially all of its assets to any Person, unless:

- (1) the Person formed by or surviving such consolidation or merger (if other than the Company), or to which such sale, lease, conveyance or other disposition shall be made (collectively, the “Successor”), is a corporation, limited liability company, general partnership or limited partnership organized and existing under the laws of the United States or any state thereof or the District of Columbia, and the Successor assumes by supplemental indenture all of the obligations of the Company under the Indenture; *provided*

that unless the Successor is a corporation, a corporate co-issuer of the Notes will be added to the Indenture by such supplemental indenture; and

(2) immediately after giving effect to such transaction, no Event of Default shall have occurred and be continuing.

Except in transactions that will result in the release of the Guarantee of a Guarantor as provided under “—Guarantees,” no Guarantor may consolidate or merge with or into (whether or not such Guarantor is the surviving Person) another Person (other than the Company or another Guarantor) unless:

- (1) the Person formed by or surviving any such consolidation or merger (if other than such Subsidiary Guarantor) assumes all the obligations of such Subsidiary Guarantor under the Indenture and the Notes pursuant to a supplemental indenture; and
- (2) immediately after such transaction, no Default or Event of Default exists.

Notwithstanding the foregoing, the Company or any Guarantor may merge with an Affiliate of it incorporated or organized solely for the purpose of reincorporating or reorganizing the Company or Guarantor in another jurisdiction.

Upon satisfaction of the foregoing requirements with respect to a merger, consolidation or sale or disposition of all or substantially all of the assets of the Company or a Guarantor, the predecessor Company or Guarantor, as the case may be, will be released from its obligations under the Indenture and the successor Company or Guarantor, as the case may be, will succeed to, and be substituted for, and may exercise every right and power of, the Company or such Guarantor, as the case may be, under the Indenture, but, in the case of a lease of all or substantially all its assets, the predecessor Company will not be released from the obligation to pay the principal of and interest on the Notes.

SEC Reports. The Company will furnish or file with the Trustee, within 15 days after it files the same with the SEC, copies of the annual reports and the information, documents and other reports (or copies of such portions of any of the foregoing as the SEC may by rules and regulations prescribe) that the Company is required to file with the SEC pursuant to Section 13 or 15(d) of the Exchange Act. If the Company is not subject to the requirements of Section 13 or 15(d) of the Exchange Act and the Notes are subject to restrictions on transfer by Persons other than Affiliates of the Company under Rule 144 under the Securities Act, the Company will furnish to all holders of the Notes and prospective purchasers of the Notes designated by the holders of the Notes, promptly on their request, the information required to be delivered pursuant to Rule 144A(d)(4) promulgated under the Securities Act. For purposes of this covenant, the Company will be deemed to have furnished such reports and information to, or filed such reports and information with, the Trustee and the holders of Notes and prospective purchasers as required by this covenant if it has filed such reports or information with the SEC via the EDGAR filing system or otherwise made such reports or information publicly available on a freely accessible page on the Company’s website; *provided, however*, that the Trustee shall have no obligation whatsoever to determine whether or not such reports and information have been posted on such website.

Events of Default

The following will be Events of Default with respect to each series of Notes:

- (1) default by the Company or any Guarantor in the payment of principal of or any premium on such series of Notes when due and payable at Maturity;
- (2) default by the Company or any Guarantor in the payment of any installment of interest on such series of Notes when due and payable and continuance of such default for 30 days;
- (3) default on any other Indebtedness of the Company or any Guarantor if either:

- (A) such default results in the acceleration of the maturity of any such Indebtedness having a principal amount of \$50.0 million or more individually or, taken together with the principal amount of any other such Indebtedness the maturity of which has been so accelerated, in the aggregate; or
- (B) such default results from the failure to pay when due principal of any such Indebtedness, after giving effect to any applicable

grace period (a “Payment Default”), having a principal amount of \$50.0 million or more individually or, taken together with the principal amount of any other Indebtedness under which there has been a Payment Default, in the aggregate;

provided that if any such default is cured or waived or any such acceleration is rescinded, or such Indebtedness (or overdue portion thereof) is repaid, within a period of 30 days from the continuation of such default beyond any applicable grace period or the occurrence of such acceleration, as the case may be, such Event of Default and any consequent acceleration of such series of Notes shall be rescinded, so long as any such rescission does not conflict with any judgment or decree or applicable provision of law;

- (4) default by the Company in the performance or breach of the provisions described under “—Certain Covenants—Limitations on Mergers and Consolidations,” or the failure to make or consummate a Change of Control Offer in accordance with the provisions of “—Change of Control;”
- (5) default in the performance, or breach of, any covenant or agreement of the Company or any Guarantor in the Indenture applicable to such series of Notes and, in each such case, failure to remedy such default within a period of 60 days after written notice thereof from the Trustee or Holders of 25% of the principal amount of such series of Notes; *provided, however*, that the Company will have 90 days following such written notice to remedy or receive a waiver for any failure to comply with its obligations under the Indenture so long as the Company is attempting to remedy any such failure as promptly as reasonably practicable;
- (6) the failure of a Guarantee by a Guarantor that is a Significant Subsidiary of such series of Notes to be in full force and effect, or the denial or disaffirmance by such entity thereof, in each case except in accordance with the Indenture; or
- (7) certain events involving bankruptcy, insolvency or reorganization of the Company or any Guarantor that is a Significant Subsidiary.

The Indenture provides that the Trustee may withhold notice to the Holders of any series of Notes of any default (except in payment of principal of, or any premium or interest on, any Notes) if the Trustee considers it in the interest of the Holders of such series of Notes to do so.

If an Event of Default (other than an Event of Default relating to certain events of bankruptcy, insolvency or reorganization of the Company) occurs and is continuing with respect to any series of Notes, the Trustee or the Holders of not less than 25% in principal amount of the outstanding Notes of such series may declare the unpaid principal of, premium, if any, and accrued but unpaid interest on, all the Notes of such series then outstanding to be due and payable. Upon such a declaration, such principal, premium, if any, and interest will be due and payable immediately. If an Event of Default relating to certain events of bankruptcy, insolvency or reorganization of the Company occurs, the principal of, any premium, if any, and interest on, all the Notes will become and be immediately due and payable without any declaration or other act on the part of the Trustee or any Holder. Under certain circumstances, the Holders of a majority in principal amount of the outstanding Notes of any series of Notes may rescind any such acceleration with respect to such series of Notes and its consequences.

No Holder of any series of Notes may pursue any remedy under the Indenture unless:

- (1) the Trustee shall have received written notice of a continuing Event of Default;
- (2) the Trustee shall have received a written request from Holders of at least 25% in principal amount of the Notes of such series to pursue such remedy;

- (3) the Trustee shall have received indemnity from the Holders reasonably satisfactory to it;
- (4) the Trustee shall have failed to act for a period of 60 days after receipt of such written notice, request and offer of indemnity; and
- (5) no direction inconsistent with such written request has been given to the Trustee during such 60-day period by the Holders of a majority in principal amount of the Notes of such series;

provided, however, such provision does not affect the right of a Holder of any Notes of such series to sue for enforcement of any overdue payment thereon.

The Holders of a majority in principal amount of the outstanding Notes of any series of Notes will have the right to direct the time, method and place of conducting any proceeding for exercising any remedy available to the Trustee for such series of Notes, subject to certain limitations specified in the Indenture. The Trustee shall be under no obligation and may refuse to perform any duty or exercise any right, duty or power hereunder unless it receives indemnity satisfactory to it against any loss, liability, claim, damage or expense.

Modification and Waiver

Supplements and amendments to the Indenture or any series of Notes may be made by the Company, the Guarantors and the Trustee with the

consent of the Holders of a majority in aggregate principal amount of all Notes (taken together as a single class) then outstanding and affected by such amendment or supplement; *provided* that no such modification or amendment may, without the consent of each Holder of such series affected thereby:

- (1) reduce the percentage of principal amount of Notes of such series whose Holders must consent to an amendment, supplement or waiver of any provision of the Indenture or the Notes of such series;
- (2) reduce the rate or change the time for payment of interest, including default interest, if any, on the Notes of such series;
- (3) reduce the principal amount of any Note of such series or change the Maturity Date of the Notes of such series;
- (4) reduce the amount payable upon redemption of any Note of such series;
- (5) waive any Event of Default in the payment of principal of, any premium or interest on, the Notes of such series (except a default in payment that has become due solely because of an acceleration that has been rescinded);
- (6) make any Note of such series payable in money other than that stated in such Note;
- (7) impair the right of Holders of Notes of such series to receive payment of the principal of and interest on Notes on the respective due dates therefor and to institute suit for the enforcement of any such payment; or
- (8) make any change in the percentage of principal amount of Notes of such series necessary to waive compliance with certain provisions of the Indenture.

For the avoidance of doubt, none of the foregoing clauses (1) through (8) will apply to any amendment of the provisions described under “—Change of Control” or any definitions related thereto.

Notwithstanding any of the foregoing, supplements and amendments of the Indenture or any series of Notes may be made by agreement among the Company, the Guarantors and the Trustee without the consent of any Holders in certain limited circumstances, including:

- (1) to cure any ambiguity, omission, defect or inconsistency;

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- (2) to provide for the assumption of the obligations of the Company or any Guarantor under the Indenture upon the merger, consolidation or sale or other disposition of all or substantially all of the assets of the Company or such Guarantor;
 - (3) to add to, change or eliminate any of the provisions of the Indenture; *provided* that any such addition, change or elimination shall become effective only after there are no such Notes entitled to the benefit of such provision outstanding;
 - (4) to establish the forms or terms of the Notes issued under the Indenture;
 - (5) to evidence the acceptance or appointment by a separate Trustee or successor Trustee with respect to the Notes of such series or otherwise;
 - (6) to reflect the addition or release of any Guarantor from its Guarantee of the Notes of such series, in the manner provided in the Indenture;
 - (7) to comply with any requirement of the SEC in order to effect or maintain the qualification of the Indenture under the Trust Indenture Act;
 - (8) to provide for uncertificated Notes of such series in addition to certificated Notes of such series;
 - (9) to mortgage, pledge, hypothecate or grant a security interest in favor of the Trustee for the benefit of the holders of the Notes of such series as security for the payment and performance of the Company’s and any Guarantor’s obligations under the Indenture, in any property or assets, including any of which are required to be mortgaged, pledged or hypothecated, or in which a security interest is required to be granted to or for the benefit of the Trustee pursuant to the Indenture or otherwise;
 - (10) to comply with the rules of any applicable securities Depository;
 - (11) to conform the text of the Indenture, the Notes of such series or the Guarantees to any provision of this “Description of Notes” to the extent that such provision in this “Description of Notes” was intended to be a verbatim recitation of a provision of the Indenture, the Notes of such series or the Guarantees; or
 - (12) to make any change that would provide any additional benefit to the Holders of the Notes of such series or that does not adversely affect

the rights of any Holder in any material respect.

The Holders of a majority in aggregate principal amount of the outstanding Notes of such series may waive compliance with or any past default under the Indenture, except a default in the payment of principal, or any premium or interest (other than a default in payment that has become due solely because of an acceleration that has been rescinded).

Legal Defeasance and Covenant Defeasance

The Company may, at its option and at any time, elect to have its obligations discharged with respect to any series of Notes (“Legal Defeasance”). Such Legal Defeasance means that the Company and any Guarantors will be deemed to have paid and discharged the entire Indebtedness represented by the outstanding Notes of such series and any Guarantees thereof, except for:

- (1) the rights of Holders of outstanding Notes of such series to receive payments solely from the trust fund described below in respect of the principal of, and any premium and interest on such Notes when such payments are due;
- (2) the Company’s obligations with respect to such series of Notes concerning the issuance of temporary Notes, transfers and exchanges of the Notes, replacement of mutilated, destroyed, lost or stolen Notes, the maintenance of an office or agency where the Notes may be tendered for transfer or exchange or presented for payment, and duties of paying agents and conversion agents;

- (3) the rights, powers, trusts, duties and immunities of the Trustee, and the Company’s obligations in connection therewith; and
- (4) the Defeasance provisions of the Indenture.

In addition, the Company may, at its option and at any time, elect to have the obligations of the Company released with respect to certain covenants described under “—Certain Covenants” (“Covenant Defeasance”), and thereafter any omission to comply with such obligations shall not constitute a Default or Event of Default. In the event Covenant Defeasance occurs, certain events (not including non-payment) described under “—Events of Default” will no longer constitute an Event of Default. If we exercise our Legal Defeasance or Covenant Defeasance option, each Guarantor will be released from all its obligations under the Indenture and its Guarantee with respect to the applicable series of Notes and any security granted to secure such Notes will be released.

In order to exercise either Legal Defeasance or Covenant Defeasance under the Indenture with respect to any series of Notes:

- (1) the Company must irrevocably deposit with the Trustee, in trust, for the benefit of the Holders of the Notes of such series, cash in U.S. Legal Tender, U.S. Government Securities, or a combination thereof, in such amounts as will be sufficient, in the opinion of a nationally recognized firm of independent public accountants, to pay the principal of, and any premium and interest on, the outstanding Notes of such series on each date on which such principal, and any premium and interest is due and payable or on any redemption date established pursuant to the Indenture;
- (2) in the case of Legal Defeasance, the Company must deliver to the Trustee an opinion of counsel reasonably acceptable to the Trustee confirming that the Company has received from or there has been published by, the Internal Revenue Service a ruling, or since the date of the Indenture, there has been a change in the applicable U.S. federal income tax law, in either case to the effect that, and based thereon such opinion of counsel shall confirm that, the Holders and beneficial owners of the outstanding Notes of such series will not recognize income, gain or loss for U.S. federal income tax purposes as a result of such Legal Defeasance and will be subject to U.S. federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such Legal Defeasance had not occurred;
- (3) in the case of Covenant Defeasance, the Company shall have delivered to the Trustee an opinion of counsel reasonably acceptable to the Trustee to the effect that the Holders and beneficial owners of the outstanding Notes of such series will not recognize income, gain or loss for U.S. federal income tax purposes as a result of such Covenant Defeasance and will be subject to U.S. federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such Covenant Defeasance had not occurred;
- (4) no Default or Event of Default shall have occurred and be continuing on the date of such deposit (other than as a result of borrowing funds in connection with such defeasance or granting of Liens in connection therewith);
- (5) such Legal Defeasance or Covenant Defeasance shall not result in a breach or violation of, or constitute a default under any other material agreement, other than the Indenture, or instrument to which the Company is a party or by which the Company is bound;
- (6) the Company shall have delivered to the Trustee an officers’ certificate stating that the deposit was not made by the Company with the intent of defeating, hindering, delaying or defrauding creditors of the Company or others; and

(7) the Company shall have delivered to the Trustee an officers' certificate and an opinion of counsel each stating that the Company has complied with all conditions precedent provided for relating to the Legal Defeasance or the Covenant Defeasance.

Mandatory Redemption; No Sinking Fund

The Company is not required to make any mandatory redemption or sinking fund payments with respect to the Notes.

Satisfaction and Discharge

The Company may discharge all of its obligations under the Indenture with respect to any series of Notes, other than its obligation to register the transfer of and exchange the Notes of such series; *provided* that it either:

- (1) delivers all outstanding Notes of such series to the Trustee for cancellation; or
- (2) all such Notes not so delivered for cancellation have either become due and payable or will become due and payable at their Maturity within one year or are to be called for redemption within one year, and in the case of this clause (2) the Company has deposited with the Trustee in trust an amount of cash or U.S. Government Securities sufficient to pay the entire indebtedness of such Notes, including any premium and interest to the applicable Maturity Date or applicable redemption date and all other sums due and payable under the Indenture by the Company.

Governing Law

The Indenture, the Notes and the Guarantees will be governed by, and construed in accordance with, the laws of the State of New York.

The Trustee

Wells Fargo Bank, National Association will initially act as Trustee, paying agent and registrar for the Notes. We may also, and currently do, maintain banking and other commercial relationships with the Trustee and its Affiliates in the ordinary course of business, and the Trustee or its affiliates did, and in the future may, own Notes.

The Trustee is permitted to become an owner or pledgee of the Notes and may otherwise deal with the Company or its Subsidiaries or Affiliates with the same rights it would have if it were not Trustee. If, however, the Trustee acquires any conflicting interest (as defined in the Trust Indenture Act) after an Event of Default has occurred and is continuing, it must eliminate such conflict or resign.

In case an Event of Default shall occur (and be continuing), the Trustee will be required to use the degree of care and skill of a prudent person in the conduct of such person's own affairs. The Trustee will be under no obligation to exercise any of its powers under the Indenture at the request of any of the Holders of the Notes, unless such Holders have offered the Trustee indemnity satisfactory to it.

Payment and Transfer

Initially, the Notes will be issued only in global form registered in the name of Cede & Co., as nominee of The Depository Trust Company, the Depository. Beneficial interests in Notes in global form will be shown on, and transfers of interests in Notes in global form will be made only through, records maintained by the Depository and its participants. Any Notes in definitive form may be presented for registration of transfer or exchange at the office or agency maintained by us for such purpose (which initially will be the corporate trust office of the Trustee).

Payment of principal, or any premium or interest on Notes in global form registered in the name of the Depository's nominee will be made in immediately available funds to the Depository's nominee, as the registered Holder of such global notes. If any Notes are no longer represented by a global note, payment of interest on the Notes in definitive form may, at our option, be made at the corporate trust office of the Trustee indicated above or by check mailed directly to Holders at their respective registered addresses or by wire transfer to an account designated by a Holder.

If any interest payment date, Maturity Date or redemption date falls on a day that is not a Business Day, the payment will be made on the next Business Day with the same force and effect as if made on the relevant interest payment date, Maturity Date or redemption date. No interest will accrue for the period from and after the applicable interest payment date, Maturity Date or redemption date.

The Notes may be transferred or exchanged, and they may be presented for payment, at the office of the Trustee indicated in the Indenture, subject to the limitations provided in the Indenture, without the payment of any service charge, other than any applicable tax or governmental charge.

The registered Holder of a Note will be treated as the owner of it for all purposes, and all references in this “Description of Notes” to “Holders” mean holders of record, unless otherwise indicated.

Certain Definitions

The following is a summary of certain defined terms used in the Indenture. Reference is made to the Indenture for the full definition of all such terms and for the definitions of capitalized terms used in this prospectus and not defined below.

“*Acquired Debt*” means Indebtedness of a Person (1) existing at the time such Person becomes a Restricted Subsidiary or merges with or into the Company or a Restricted Subsidiary or (2) assumed in connection with the acquisition of assets from such Person, in each case other than Indebtedness incurred in connection with, or in contemplation of, such Person becoming a Restricted Subsidiary or such acquisition, as the case may be. Acquired Debt shall be deemed to be incurred on the date of the related acquisition of assets from any Person or the date the acquired Person becomes a Restricted Subsidiary or merges with or into the Company or a Restricted Subsidiary, as the case may be.

“*Adjusted Consolidated Net Tangible Assets*” means, without duplication, as of the date of determination:

- (i) the sum of:
 - (a) discounted future net revenues from proved oil and gas reserves of the Company and its Restricted Subsidiaries calculated in accordance with SEC guidelines before any state, federal or foreign income taxes (“pre-tax”), as estimated by the Company in a reserve report prepared as of the end of the Company’s most-recently completed fiscal year for which audited financial statements are then available, as increased by, as of the date of determination, the estimated discounted future net revenues from (1) estimated proved oil and gas reserves acquired since such year-end, which reserves were not reflected in such year-end reserve report, and (2) estimated increases in proved oil and gas reserves since such year-end due to exploration, development or exploitation activities or due to changes in geological conditions (or understandings thereof) or other factors which would, in accordance with standard industry practice, cause such revisions, in each case on a pre-tax basis calculated in accordance with SEC guidelines (utilizing the prices utilized in such year-end reserve report) increased by the accretion of the discount from the date of the reserve report to the date of determination and the effect to proved reserves and future net revenues from estimated development cost incurred, and decreased by, as of the date of determination, the estimated discounted future net revenues from (3) estimated proved oil and gas reserves reflected in such year-end report produced or disposed of since such year-end and (4) estimated oil and gas reserves attributable to downward revisions of estimates of proved oil and gas reserves since such year-end due to changes in geological conditions (or understandings thereof) or other factors which would, in accordance with standard industry practice, cause such revisions, in each case on a pre-tax basis calculated in accordance with SEC guidelines (utilizing the prices utilized in such year-end reserve report); *provided* that, in the case of each of the determinations made pursuant to clauses (1) through (4), such increases and decreases shall be as estimated by the Company’s petroleum engineers, plus
 - (b) the capitalized costs that are attributable to oil and gas properties of the Company and its Restricted Subsidiaries to which no proved oil and gas reserves are attributable, based on the Company’s books

and records as of a date no earlier than the date of the Company’s latest annual or quarterly financial statements, plus

- (c) the Net Working Capital on a date no earlier than the date of the Company’s latest annual or quarterly financial statements, plus
- (d) the greater of (1) the net book value on a date no earlier than the date of the Company’s latest annual or quarterly financial consolidated statements and (2) the appraised value, as estimated by independent appraisers, of other tangible assets (including, without duplication, investments in unconsolidated Restricted Subsidiaries) of the Company and its Restricted Subsidiaries, as of the date no earlier than the date of the Company’s latest audited financial statements (*provided* that the Company shall not be required to obtain such appraisal of such assets if no such appraisal has been performed), plus
- (e) any net gas balancing assets of the Company and its Restricted Subsidiaries reflected in the Company’s latest annual or quarterly consolidated financial statements,

minus (ii) the sum of:

- (a) minority interests, plus
- (b) any net gas balancing liabilities of the Company and its Restricted Subsidiaries reflected in the Company's latest annual or quarterly consolidated financial statements (to the extent not deducted in calculating Net Working Capital in accordance with clause (i)(c) of this definition), plus
- (c) to the extent included in (i)(a) above, the discounted future net revenues, calculated on a pre-tax basis in accordance with SEC guidelines (utilizing the prices utilized in the Company's year-end reserve report), attributable to reserves which are required to be delivered to third parties to fully satisfy the obligations of the Company and its Restricted Subsidiaries with respect to Volumetric Production Payments (determined, if applicable, using the schedules specified with respect thereto), plus
- (d) the discounted future net revenues, calculated on a pre-tax basis in accordance with SEC guidelines, attributable to reserves subject to Dollar-Denominated Production Payments which, based on the estimates of production and price assumptions included in determining the discounted future net revenues specified in (i)(a) above, would be necessary to fully satisfy the payment obligations of the Company and its Restricted Subsidiaries with respect to Dollar-Denominated Production Payments (determined, if applicable, using the schedules specified with respect thereto).

“*Affiliate*” of any specified Person means any other Person directly or indirectly controlling or controlled by or under direct or indirect common control with such specified Person. For the purposes of this definition, “control” when used with respect to any specified Person means the power to direct the management and policies of such Person, directly or indirectly, whether through the ownership of voting securities, by contract or otherwise; and the terms “controlling” and “controlled” have meanings correlative to the foregoing.

“*Board of Directors*” means, with respect to any Person, the Board of Directors or other governing body of such Person or any committee thereof duly authorized to act on behalf of such Board of Directors or such other governing body.

“*Capital Stock*” of any Person means any and all shares, units, interests, participations, rights in or other equivalents (however designated) of such Person's capital stock, other equity interests whether outstanding before or issued after the Issue Date, partnership interests (whether general or limited), joint venture interests, limited liability company interests, any other interest or participation that confers on a Person the right to receive a share of the profits and losses of, or distributions of assets of, the issuing Person, including any Preferred Stock, and any rights (other than debt securities convertible into Capital Stock), warrants or options exchangeable for or convertible into such Capital Stock.

“*Change of Control*” means the occurrence of any of the following events:

- (1) any “person” or “group” (as such terms are used in Sections 13(d) and 14(d) of the Exchange Act), other than, prior to the completion of the Spin-off Distribution, Occidental or any Subsidiary or Affiliate thereof, is or becomes the “beneficial owner” (as defined in Rules 13d-3 and 13d-5 under the Exchange Act, except that a Person shall be deemed to have beneficial ownership of all shares that such Person has the right to acquire, whether such right is exercisable immediately or only after the passage of time), directly or indirectly, of more than 50% of the total outstanding Voting Stock of the Company (measured by voting power rather than the number of shares), other than any such transaction in which the outstanding Voting Stock of the Company is changed into or exchanged for Voting Stock of the surviving Person or any parent thereof that collectively represents at least 50% of the total outstanding Voting Stock (measured by voting power rather than the number of shares) of the surviving Person or such parent immediately following such transaction;
- (2) the Company sells, assigns, conveys, transfers, leases or otherwise disposes of all or substantially all of its assets to any Person other than the Company or a Subsidiary; or
- (3) the Company is liquidated or dissolved or adopts a plan of liquidation or dissolution other than in a transaction which complies with the provisions described under “—Certain Covenants—Limitations on Mergers and Consolidations.”

Notwithstanding the foregoing, a Change of Control shall not be deemed to occur upon the consummation of any actions undertaken by the Company or any Restricted Subsidiary solely for the purpose of changing the legal structure of the Company or such Restricted Subsidiary. None of the Spin-off or the Transactions constitute a Change of Control.

“*Change of Control Triggering Event*” means the occurrence of both a Change of Control and a Rating Decline.

“*Credit Agreement*” means the Credit Agreement dated September 24, 2014 among the Company, the Guarantors, JPMorgan Chase Bank, N.A., as administrative agent, a swingline lender and a letter of credit issuer, and the lenders party thereto from time to time, as such agreement, in whole or in part, in one or more instances, may thereafter be amended, renewed, extended, increased, substituted, refinanced, restructured, replaced, supplemented or otherwise modified from time to time (including, without limitation, any successive renewals, extensions, increases, substitutions, refinancings, restructurings, replacements, supplementations or other modifications of the foregoing).

“*Credit Facility*” means, one or more debt facilities (including, without limitation, the debt facilities arising pursuant to the Credit Agreement), loan agreements or commercial paper facilities, in each case with banks, investment banks, insurance companies, mutual funds and/or other institutional lenders providing for revolving credit loans, term loans, receivables financing (including through the sale of receivables to such lenders or to special purpose entities formed to borrow from (or sell receivables to) such lenders against such receivables) or letters of credit, in each case, as amended, extended, restated, renewed, refunded, replaced (whether contemporaneously or otherwise) or refinanced (in each case with Credit Facilities with such lenders), supplemented or otherwise modified (in whole or in part and without limitation as to amount, terms, conditions, covenants and other provisions) from time to time.

“*Default*” means any event which is, or after notice or passage of time or both would be, an Event of Default.

“*Depository*” means, unless otherwise specified by the Company with respect any Notes issuable or issued in whole or in part in the form of one or more Global Securities, The Depository Trust Company, New York, New York, or any successor thereto registered as a clearing agency under the Exchange Act or other applicable statute or regulations.

“*Dollar-Denominated Production Payment*” means a production payment required to be recorded as a borrowing in accordance with GAAP, together with all undertakings and obligations in connection therewith.

“*Exchange Act*” means the Securities Exchange Act of 1934, as amended, and the rules and regulations of the SEC thereunder.

“*Funded Debt*” means, with regard to any Person, all Indebtedness incurred, created, assumed or guaranteed by such Person, which matures, or is renewable by such Person to a date, more than one year after the date as of which Funded Debt is being determined.

“*GAAP*” means United States generally accepted accounting principles as in effect from time to time.

“*Global Security*” means a Note in global form that evidences all or part of the Notes and registered in the name of the Depository for the Notes or a nominee thereof.

“*guarantee*” means any obligation, contingent or otherwise, of any Person directly or indirectly guaranteeing any Indebtedness of any other Person and any obligation, direct or indirect, contingent or otherwise, of such Person:

- (1) to purchase or pay (or advance or supply funds for the purchase or payment of) such Indebtedness of such other Person; or
- (2) entered into for purposes of assuring in any other manner the obligee of such Indebtedness of the payment thereof or to protect such obligee against loss in respect thereof (in whole or in part); *provided, however*, that the term “guarantee” will not include endorsements for collection or deposit in the ordinary course of business. The term “guarantee” used as a verb has a corresponding meaning.

“*Guarantor*” means any Subsidiary of the Company which is a guarantor of the Notes, including any Person that is required after the Issue Date to guarantee the Notes pursuant to the covenant described under “—Certain Covenants—Future Guarantees” until the Guarantee of such Guarantor is released in accordance with the Indenture or a successor replaces such Person pursuant to the applicable provisions of the Indenture (and, thereafter, means such successor).

“*Holder*” means the Person in whose name a Note is registered in the Register.

“*Indebtedness*” means, without duplication, with respect to any Person,

- (a) all obligations of such Person, including those evidenced by bonds, notes, debentures or similar instruments, for the repayment of money borrowed (whether or not the recourse of the lender is to the whole of the assets of such Person or only to a portion thereof); and
- (b) all liabilities of others of the kind described in the preceding clause (a) that such Person has guaranteed.

Neither Dollar-Denominated Production Payments nor Volumetric Production Payments shall be deemed to be Indebtedness.

“*Investment Grade Rating*” means a rating equal to or higher than (1) Baa3 (or the equivalent) with a stable or better outlook by Moody’s and (2) BBB- (or the equivalent) with a stable or better outlook by S&P; or if either such entity ceases to rate Notes for reasons outside of the Company’s control, the equivalent investment grade rating from another nationally recognized statistical rating agency or agencies, as the case may be, selected by the Company.

“*Issue Date*” means, with respect to the Notes, the date of original issuance of the Notes.

“*Lien*” means any mortgage or deed of trust, charge, pledge, lien (statutory or otherwise), privilege, security interest, assignment, deposit,

arrangement, hypothecation, claim, preference, priority or other encumbrance for security purposes upon or with respect to any property of any kind (including any conditional sale, capital lease or other title retention agreement, any leases in the nature thereof, and any agreement to give any security interest), real or personal, movable or immovable, now owned or hereafter acquired. References in the Indenture to Liens allowed to exist upon any particular item of Property shall also be deemed (whether or not stated specifically) to allow Liens to exist upon any accessions, improvements or additions to, such property, upon any contractual rights relating

primarily to such Property, and upon any replacements or proceeds of such Property or of such accessions, improvements, additions or contractual rights.

“*Maturity*” means, with respect to the applicable series of Notes, the date on which the principal of such series of Notes or an installment of principal becomes due and payable as provided therein or by the Indenture, whether at the applicable Maturity Date or by declaration of acceleration, call for redemption or otherwise.

“*Maturity Date*” means, with respect to the applicable series of Notes, the fixed date specified pursuant to the Indenture as to such series of Notes on which the principal of such series of Notes becomes due and payable as provided therein or by the Indenture.

“*MLP Subsidiary*” means a Subsidiary of the Company that is a master limited partnership or limited liability company or other pass-through entity, in each case having a class of equity securities that is listed for trading (or that is reasonably expected to be so listed for trading within six months) on a national securities exchange.

“*Moody’s*” means Moody’s Investor Services Inc., or any successor thereto, including a replacement rating agency selected by us as provided in the definition of Rating Agency.

“*Net Working Capital*” means the sum of (i) all current assets of the Company and its Restricted Subsidiaries plus (ii) the amount of borrowings available to be incurred under the Credit Agreement, less all current liabilities of the Company and its Restricted Subsidiaries, except current liabilities included in Indebtedness, in each case (other than in respect of the amount of borrowings available referred to in the preceding clause (ii)) as set forth in consolidated financial statements of the Company prepared in accordance with GAAP; *provided, however*, that all of the following shall be excluded in the calculation of Net Working Capital: (a) current assets or liabilities relating to the mark-to-market value of hedging arrangements, (b) any current assets or liabilities relating to non-cash charges arising from any grant of Capital Stock, options to acquire Capital Stock, or other equity-based awards, and (c) any current assets or liabilities relating to non-cash charges or accruals for future abandonment liabilities.

“*Permitted Lien*” means:

- (1) Liens existing on the Issue Date;
- (2) Liens securing Indebtedness under Credit Facilities in an aggregate principal amount outstanding at any one time not to exceed \$4,000.0 million;
- (3) Liens securing any renewal, extension, substitution, refinancing or replacement of secured Indebtedness; *provided*, that such Liens extend to or cover only the property or assets then securing the Indebtedness being refinanced and that the Indebtedness being refinanced was not incurred under the Credit Facilities in reliance on clause (2) above;
- (4) Liens on, or related to, oil and gas properties to secure all or part of the costs incurred in the ordinary course of business of exploration, drilling, development, production, gathering, processing, marketing or operation thereof, in each case, which are not incurred in connection with the borrowing of money;
- (5) any Lien arising by reason of:
 - (A) any judgment, decree or order of any court, so long as such Lien is adequately bonded and any appropriate legal proceedings which may have been duly initiated for the review of such judgment, decree or order shall not have been finally terminated or the period within which such proceedings may be initiated shall not have expired;
 - (B) taxes, assessments or governmental charges or claims that are not yet delinquent or which are being contested in good faith by appropriate proceedings promptly instituted and diligently conducted; *provided* that any reserve or other appropriate provision as will be required in conformity with GAAP will have been made therefor;

- (C) security made in the ordinary course of business in connection with workers' compensation, unemployment insurance or other types of social security;
- (D) good faith deposits in connection with tenders, leases and contracts (other than contracts for the payment of Indebtedness);
- (E) zoning restrictions, easements, licenses, reservations, title defects, rights of others for rights of way, utilities, sewers, electric lines, telephone or telegraph lines, and other similar purposes, provisions, covenants, conditions, waivers, restrictions on the use of property or minor irregularities of title (and with respect to leasehold interests, mortgages, obligations, Liens and other encumbrances incurred, created, assumed or permitted to exist and arising by, through or under a landlord or owner of the leased property, with or without consent of the lessee), none of which materially impairs the use of any parcel of property material to the operation of the business of the Company or any Subsidiary or the value of such property for the purpose of such business;
- (F) deposits to secure public or statutory obligations, or in lieu of surety or appeal bonds;
- (G) operation of law or contract in favor of mechanics, carriers, warehousemen, landlords, materialmen, laborers, employees, suppliers and similar persons, incurred in the ordinary course of business for sums which are not yet delinquent for more than 30 days or are being contested in good faith by negotiations or by appropriate proceedings which suspend the collection thereof;
- (6) Liens in favor of collecting or payor banks having a right of setoff, revocation, refund or chargeback with respect to money or instruments of the Company or any Subsidiary on deposit with or in possession of such bank;
- (7) Liens in favor of the United States, any state thereof, any foreign country or any department, agency or instrumentality or political subdivision of any such jurisdiction, to secure partial, progress, advance or other payments pursuant to any contract or statute or to secure any Indebtedness incurred for the purpose of financing all or any part of the purchase price or the cost of constructing or improving the property subject to such Liens, including, without limitation, Liens to secure Funded Debt of the pollution control or industrial revenue bond type;
- (8) any Lien securing Acquired Debt created prior to (and not created in connection with, or in contemplation of) the incurrence of such Indebtedness by the Company or any Subsidiary and Liens on any Property at the time of (and not created in connection with, or in contemplation of) acquisition thereof by the Company or a Restricted Subsidiary; *provided* that such Liens do not encumber other Property of the Company or any Restricted Subsidiary;
- (9) any Lien on Property to secure (i) all or any portion of the cost of acquiring, constructing, altering, improving or repairing any Property or assets or improvements used in connection with such Property, and (ii) Indebtedness incurred by the Company or any Subsidiary to provide funds for the activities set forth in clause (i) above; *provided* that the aggregate principal amount of Indebtedness secured by such Liens does not exceed the cost of the Property so acquired, constructed or improved and such Liens are created within 365 days of construction, acquisition or improvement of such Property and do not encumber any other Property of the Company or any Subsidiary other than such Property and assets affixed or appurtenant thereto;
- (10) any Lien to secure performance bids, leases (including, without limitation, statutory and common law landlord's liens), statutory obligations, letters of credit and other obligations of a like nature and incurred in the ordinary course of business of the Company or any Subsidiary and not securing or supporting Indebtedness, and any Lien to secure statutory or appeal bonds;
- (11) leases and subleases of real property which do not materially interfere with the ordinary conduct of the business of the Company or any of its Restricted Subsidiaries;

- (12) any Lien created by a mortgage related to a property or building that is used as the Company's headquarters or other principal place of business;
- (13) Liens on the Capital Stock of any Subsidiary other than a Restricted Subsidiary;
- (14) Liens in favor of the Company or any Guarantor; or
- (15) any Lien in favor of the Trustee for the benefit of the Trustee or the holders of the Notes or otherwise securing the Notes or the Subsidiary Guarantees, or liens on funds held in trust for the benefit of third parties.

“*Person*” means any individual, corporation, partnership, limited liability company, joint venture, trust, estate, association, unincorporated organization or government or any agency or political subdivision thereof.

“*Property*” means, with respect to any Person, any interest of such Person in any kind of property or asset, whether real, personal or mixed, or tangible or intangible, including Capital Stock and other securities issued by any other Person (but excluding Capital Stock or other securities issued by such first mentioned Person).

“*Rating Agency*” means

- (1) each of Moody’s and S&P; and
- (2) if either of Moody’s or S&P ceases to rate a series of Notes or fails to make a rating of such series of Notes publicly available for reasons outside of our control, a “nationally recognized statistical rating organization” within the meaning of Section 3(a)(62) of the Exchange Act selected by us as a replacement rating agency for Moody’s or S&P, or both, as the case may be.

“*Rating Date*” means the earlier of the date of public notice of (i) the occurrence of a Change of Control or (ii) our intention to effect a Change of Control.

“*Rating Decline*” shall be deemed to have occurred with respect to a series of Notes if, no later than 30 days after the Rating Date (which period shall be extended so long as the rating of any series of Notes is under publicly announced consideration for possible downgrade by either of the Rating Agencies and the other Rating Agency has either downgraded, or publicly announced that it is considering downgrading, such Notes), each of the Rating Agencies decreases its rating of such series of Notes to a rating that is below its rating of such series of Notes on the day immediately prior to the earlier of (i) the date of the first public announcement of the possibility of a proposed transaction that would result in a Change of Control or (ii) the date that the possibility of such transaction is disclosed to either of the Rating Agencies. Notwithstanding the foregoing, if such Notes have an Investment Grade Rating by each of the Rating Agencies immediately prior to the Rating Date, then “*Rating Decline*” means a decrease in the ratings of such Notes by one or more gradations (including gradations within categories as well as between rating categories) by each of the Rating Agencies such that the rating of such Notes by each of the Rating Agencies falls below an Investment Grade Rating no later than 30 days after the Rating Date (which 30-day period will be extended so long as the rating of such Notes is under publicly announced consideration for possible downgrade by either of the Rating Agencies and the other Rating Agency has either downgraded, or publicly announced that it is considering downgrading, such Notes).

“*Restricted Subsidiary*” of any Person means any Subsidiary of the Person that is not an MLP Subsidiary or a royalty trust.

“*S&P*” means Standard & Poor’s Ratings Services, a division of McGraw-Hill, Inc., or any successor thereto, including a replacement rating agency selected by us as provided in the definition of Rating Agency.

“*SEC*” means the Securities and Exchange Commission, as from time to time constituted, created under the Exchange Act, or if at any time after the execution of the Indenture such Commission is not existing and performing the duties now assigned to it under the Securities Act and the Exchange Act then the body performing such duties at such time.

“*Securities Act*” means the Securities Act of 1933, as amended, or any successor statute, and the rules and regulations promulgated by the SEC thereunder.

“*Significant Subsidiary*” has the meaning set forth in Rule 1-02 of Regulation S-X under the Securities Act as in effect on the Issue Date.

“*Subsidiary*” of a Person means

- (1) any corporation more than 50% of the outstanding voting power of the Voting Stock of which is owned or controlled, directly or indirectly, by such Person or by one or more other Subsidiaries of such Person, or by such Person and one or more other Subsidiaries thereof, or
- (2) any limited partnership of which such Person or any Subsidiary of such Person is the sole general partner or general partners, or
- (3) any other Person in which such Person, or one or more other Subsidiaries of such Person, or such Person and one or more other Subsidiaries, directly or indirectly, owns more than 50% of the outstanding partnership or similar interests having the power, by contract or otherwise, to direct or cause the direction of the policies, management and affairs thereof.

“*U.S. Government Securities*” means securities that are (1) direct obligations of the United States of America for the payment of which its full faith and credit is pledged or (2) obligations of a Person controlled or supervised by and acting as an agency or instrumentality of the United States

of America the payment of which is unconditionally guaranteed as a full faith and credit obligation by the United States of America, which, in either case under clauses (1) or (2) are not callable or redeemable at the option of the issuer thereof.

“*U.S. Legal Tender*” means such coin or currency of the United States as at the time of payment shall be legal tender for the payment of public and private debts.

“*Volumetric Production Payment*” means a production payment that is recorded as a sale in accordance with GAAP, whether or not the sale price must be recorded as deferred revenue, together with all undertakings and obligations in connection therewith.

“*Voting Stock*” of a Person means Capital Stock of such Person of the class or classes pursuant to which the holders thereof have the general voting power under ordinary circumstances to elect at least a majority of the Board of Directors, managers or trustees of such Person (irrespective of whether or not at the time Capital Stock of any other class or classes shall have or might have voting power by reason of the happening of any contingency).

BOOK-ENTRY; DELIVERY AND FORM

Except as set forth below, the exchange notes will be represented by one or more permanent global notes in registered form without interest coupons (“Global Notes”). The Global Notes will be deposited upon issuance with the Trustee as custodian for DTC, in New York, New York, and registered in the name of DTC’s nominee, Cede & Co., for credit to an account of a direct or indirect participant in DTC as described below.

Except as set forth below, the Global Notes may be transferred, in whole and not in part, only to another nominee of DTC or to a successor of DTC or its nominee. Beneficial interests in the Global Notes may not be exchanged for definitive notes in registered certificated form (“Certificated Notes”) except in the limited circumstances described below. See “—Exchange of Global Notes for Certificated Notes.” Except in the limited circumstances described below, owners of beneficial interests in the Global Notes will not be entitled to receive physical delivery of such notes in certificated form.

Beneficial interests in the Global Notes may be held through the Euroclear System (“Euroclear”) and Clearstream Banking, S.A. (“Clearstream”)(as indirect participants in DTC).

Transfers of beneficial interests in the Global Notes will be subject to the applicable rules and procedures of DTC and its direct or indirect participants (including, if applicable, those of Euroclear and Clearstream), which may change from time to time.

Depository Procedures

The following description of the operations and procedures of DTC, Euroclear and Clearstream is provided solely as a matter of convenience. These operations and procedures are solely within the control of the respective settlement systems and are subject to changes by them. We take no responsibility for these operations and procedures and urge investors to contact the system or their participants directly to discuss these matters.

DTC has advised us that DTC is a limited-purpose trust company organized under the laws of the State of New York, a “banking organization” within the meaning of the New York Banking Law, a member of the Federal Reserve System, a “clearing corporation” within the meaning of the Uniform Commercial Code and a “clearing agency” registered pursuant to the provisions of Section 17A of the Exchange Act. DTC was created to hold securities for its participating organizations (collectively, the “Participants”) and to facilitate the clearance and settlement of transactions in those securities between Participants through electronic book-entry changes in accounts of its Participants. The Participants include securities brokers and dealers (including the initial purchasers), banks, trust companies, clearing corporations and certain other organizations. Access to DTC’s system is also available to other entities such as banks, brokers, dealers and trust companies that clear through or maintain a custodial relationship with a Participant, either directly or indirectly (collectively, the “Indirect Participants”). Persons who are not Participants may beneficially own securities held by or on behalf of DTC only through the Participants or the Indirect Participants. The ownership interests in, and transfers of ownership interests in, each security held by or on behalf of DTC are recorded on the records of the Participants and Indirect Participants.

DTC has also advised us that, pursuant to procedures established by it:

- (1) upon deposit of the Global Notes, DTC will credit the accounts of Participants designated by the exchange agent with portions of the principal amount of the Global Notes; and
- (2) ownership of these interests in Global Notes will be shown on, and the transfer of ownership of these interests will be effected only through, records maintained by DTC (with respect to the Participants) or by the Participants and the Indirect Participants (with respect to

other owners of beneficial interests in Global Notes).

Investors in the Global Notes who are Participants in DTC's system may hold their interests therein directly through DTC. Investors in Global Notes who are not Participants may hold their interests therein indirectly through

organizations (including Euroclear and Clearstream) that are Participants in such system. Euroclear and Clearstream may hold interests in the Global Notes on behalf of their participants through customers' securities accounts in their respective names on the books of their respective depositories, which are Euroclear Bank S.A./N.V., as operator of Euroclear, and Citibank, N.A., as operator of Clearstream. All interests in the Global Notes, including those held through Euroclear or Clearstream, may be subject to the procedures and requirements of DTC. Those interests held through Euroclear or Clearstream may also be subject to the procedures and requirements of such systems.

The laws of some jurisdictions require that certain persons take physical delivery in definitive form of securities that they own and the ability to transfer beneficial interests in a Global Note to persons that are subject to those requirements will be limited to that extent. Because DTC can act only on behalf of Participants, which in turn act on behalf of Indirect Participants, the ability of a person having beneficial interests in a Global Note to pledge those interests to persons that do not participate in the DTC system, or otherwise take actions in respect of those interests, may be affected by the lack of a physical certificate evidencing those interests.

Except as described below, owners of an interest in Global Notes will not have notes registered in their names, will not receive physical delivery of definitive notes in registered certificated form, or Certificated Notes, and will not be considered the registered owners or "Holders" thereof under the indenture for any purpose.

Payments in respect of the principal of and premium, interest and additional interest, if any, on a Global Note registered in the name of DTC or its nominee will be payable to DTC in its capacity as the registered Holder under the indenture. Under the terms of the indenture, we, the guarantors, and the Trustee will treat the persons in whose names the notes, including Global Notes, are registered as the owners of such notes for the purpose of receiving payments and for all other purposes. Consequently, neither we, the guarantors, the Trustee nor our agent or an agent of the Trustee has or will have any responsibility or liability for:

- (1) any aspect of DTC's records or any Participant's or Indirect Participant's records relating to or payments made on account of beneficial ownership interests in Global Notes or for maintaining, supervising or reviewing any of DTC's records or any Participant's or Indirect Participant's records relating to the beneficial ownership interests in Global Notes; or
- (2) any other matter relating to the actions and practices of DTC or any of its Participants or Indirect Participants.

DTC has advised us that its current practice, upon receipt of any payment in respect of securities such as the notes (including principal and interest), is to credit the accounts of the relevant Participants with the payment on the payment date unless DTC has reason to believe it will not receive payment on that payment date. Each relevant Participant is credited with an amount proportionate to its beneficial ownership of an interest in the principal amount of the relevant series of notes as shown on the records of DTC. Payments by the Participants and the Indirect Participants to the beneficial owners of notes will be governed by standing instructions and customary practices and will be the responsibility of the Participants or the Indirect Participants and will not be the responsibility of DTC, the Trustee or us. Neither we nor the Trustee will be liable for any delay by DTC or any of its Participants in identifying the beneficial owners of any notes, and we and the Trustee may conclusively rely on and will be protected in relying on instructions from DTC or its nominee for all purposes.

Transfers between Participants in DTC will be effected in accordance with DTC's procedures, and will be settled in same-day funds and transfers between participants in Euroclear and Clearstream will be effected in accordance with their respective rules and operating procedures.

Subject to compliance with the transfer restrictions applicable to the exchange notes described herein, cross-market transfers between the Participants, on the one hand, and Euroclear or Clearstream participants, on the other hand, will be effected through DTC in accordance with DTC's rules on behalf of Euroclear or Clearstream, as the case may be, by its respective depository; however, such cross-market transactions will require delivery of instructions to Euroclear or Clearstream, as the case may be, by the counterparty in such system in accordance with the rules and procedures and within the established deadlines (Brussels time) of such system. Euroclear or

Clearstream, as the case may be, will, if the transaction meets its settlement requirements, deliver instructions to its respective depository to take

action to effect final settlement on its behalf by delivering or receiving interests in the relevant Global Note from DTC, and making or receiving payment in accordance with normal procedures for same-day funds settlement applicable to DTC. Euroclear participants and Clearstream participants may not deliver instructions directly to the depositories for Euroclear or Clearstream.

DTC has advised us that it will take any action permitted to be taken by a Holder of a given series of exchange notes only at the direction of one or more Participants to whose account DTC has credited the interests in the applicable series of Global Notes and only in respect of the portion of the aggregate principal amount of the applicable series of notes as to which that Participant or those Participants has or have given the relevant direction. However, if there is an Event of Default under such series of notes, DTC reserves the right to exchange the applicable Global Notes in certificated form, and to distribute those notes to its Participants.

Although DTC, Euroclear and Clearstream have agreed to the foregoing procedures in order to facilitate transfers of interests in Global Notes among Participants in DTC, Euroclear and Clearstream, they are under no obligation to perform those procedures, and may discontinue or change those procedures at any time. Neither we nor the Trustee nor any of their respective agents will have any responsibility for the performance by DTC, Euroclear, Clearstream or their respective Participants or Indirect Participants of their respective obligations under the rules and procedures governing their operations.

Exchange of Global Notes for Certificated Notes

A Global Note is exchangeable for a Certificated Note in minimum denominations of \$2,000 and in integral multiples of \$1,000 in excess of \$2,000, if:

- DTC (1) notifies us that it is unwilling or unable to continue as depository for the applicable Global Notes or (2) has ceased to be a clearing agency registered under the Exchange Act and, in either case, we fail to appoint a successor depository within 90 days;
- we, at our option and subject to the procedures of DTC, notify the Trustee in writing that we elect to cause the issuance of Certificated Notes; or
- there has occurred and is continuing a Default or an event of Default with respect to the Notes and DTC requests the issuance of Certificated Notes.

In addition, beneficial interests in a Global Note may be exchanged for Certificated Notes of the same series upon prior written notice given to the Trustee by or on behalf of DTC in accordance with the indenture. In all cases, Certificated Notes delivered in exchange for any Global Note or beneficial interests in a Global Note will be registered in the names, and issued in any approved denominations, requested by or on behalf of the depository (in accordance with its customary procedures) and will bear the applicable restrictive legend unless that legend is not required by applicable law.

Same-Day Settlement and Payment

We will make payments in respect of notes represented by Global Notes, including payments of principal, premium, if any, and interest by wire transfer of immediately available funds to the accounts specified by the DTC or its nominee. We will make all payments of principal of and premium, if any, and interest on Certificated Notes by wire transfer of immediately available funds to the accounts specified by the Holders of the Certificated Notes or, if no account is specified, by mailing a check to each Holder’s registered address. Notes represented by Global Notes are expected to trade in DTC’s Same-Day Funds Settlement System, and any permitted secondary market trading activity in notes represented by Global Notes will, therefore, be required by DTC to be settled in immediately available funds. Because of time zone differences, the securities account of a Euroclear or Clearstream participant purchasing an interest in a Global Note from a Participant will be credited, and any such crediting will be reported to the relevant Euroclear or Clearstream participant, during the securities settlement processing day (which must be a business day for Euroclear and Clearstream) immediately following the settlement date of DTC. DTC has advised us

that cash received in Euroclear or Clearstream as a result of sales of interests in a Global Note by or through a Euroclear or Clearstream participant to a Participant will be received with value on the settlement date of DTC but will be available in the relevant Euroclear or Clearstream cash account only as of the business day for Euroclear or Clearstream following DTC’s settlement date.

CERTAIN UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

The following discussion summarizes certain U.S. federal income tax considerations, as of the date of this prospectus, that may be relevant to the exchange of original notes for exchange notes pursuant to the exchange offer. This discussion is based upon the provisions of the Code, applicable U.S. Treasury Regulations promulgated thereunder, judicial authority and administrative interpretations, as of the date of this prospectus,

all of which are subject to change, possibly with retroactive effect, and all of which are subject to different interpretations. We cannot assure you that the IRS will not challenge one or more of the tax consequences described in this discussion, and we have not obtained, nor do we intend to obtain, a ruling from the IRS or an opinion of counsel with respect to the U.S. federal tax consequences discussed below.

This discussion is limited to the exchange of the original notes for exchange notes. This discussion does not address any U.S. federal tax considerations other than U.S. federal income tax considerations (such as estate and gift tax considerations), the Medicare tax on net investment income or the tax considerations arising under the laws of any foreign, state, local or other jurisdiction or any income tax treaty. In addition, this discussion does not address all tax considerations that may be important to a particular holder in light of the holder’s circumstances, or to certain categories of investors that may be subject to special rules, such as dealers in securities or currencies; traders in securities that have elected the mark-to-market method of accounting for their securities; U.S. holders whose functional currency is not the U.S. dollar; persons holding notes as part of a hedge, straddle, conversion or other “synthetic security” or integrated transaction; former U.S. citizens or long-term residents of the United States; financial institutions; insurance companies; regulated investment companies; real estate investment trusts; persons subject to the alternative minimum tax; entities that are tax-exempt for U.S. federal income tax purposes; and partnerships and other pass-through entities and holders of interests therein.

If an entity treated as a partnership for U.S. federal income tax purposes holds original notes, the U.S. federal income tax treatment of a partner of the partnership generally will depend upon the status of the partner and the activities of the partnership. If you are a partner of a partnership considering participating in the exchange offer, you are urged to consult your own tax advisor.

HOLDERS ARE URGED TO CONSULT THEIR OWN TAX ADVISORS REGARDING THE APPLICATION OF THE U.S. FEDERAL INCOME TAX LAWS TO THEIR PARTICULAR SITUATIONS AS WELL AS ANY TAX CONSEQUENCES OF THE EXCHANGE OF ORIGINAL NOTES FOR EXCHANGE NOTES UNDER THE LAWS OF ANY STATE, LOCAL OR FOREIGN JURISDICTION OR UNDER ANY APPLICABLE INCOME TAX TREATY.

Exchange of Original Notes for Exchange Notes

The exchange of original notes for exchange notes pursuant to the exchange offer will not be treated as a taxable event for U.S. federal income tax purposes. Consequently, for U.S. federal income tax purposes:

- you will not recognize gain or loss upon receipt of exchange notes for original notes pursuant to the exchange offer;
- your adjusted tax basis in the exchange notes you receive pursuant to the exchange offer will equal your adjusted tax basis in the original notes exchanged therefor; and
- your holding period for the exchange notes you receive pursuant to the exchange offer will include your holding period for the original notes exchanged therefor.

PLAN OF DISTRIBUTION

Each broker-dealer that receives exchange notes pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of exchange notes. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of exchange notes received in exchange for original notes if such original notes were acquired as a result of market-making activities or other trading activities. We have agreed to make this prospectus available to such broker-dealers upon reasonable request for the period required by the Securities Act. In addition, until September 27, 2015, all broker-dealers effecting transactions in the exchange notes may be required to deliver a prospectus.

We will not receive any proceeds from the exchange of original notes for exchange notes or from any sale of exchange notes by broker-dealers. Exchange notes received by broker-dealers for their own account pursuant to the exchange offer may be sold from time to time in one or more transactions:

- in the over-the-counter market;
- in negotiated transactions;
- through the writing of options on the exchange notes; or
- a combination of such methods of resale.

The exchange notes may be sold from time to time:

- at market prices prevailing at the time of resale;
- at prices related to such prevailing market prices; or
- at negotiated prices.

Any such resale may be made directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker-dealer or the purchasers of any such exchange notes.

Any broker-dealer that resells exchange notes received pursuant to the exchange offer and any broker or dealer that participates in a distribution of such exchange notes may be deemed to be an “underwriter” within the meaning of the Securities Act and any profit on any such resale of exchange notes and any commissions or concessions received by any such persons may be deemed to be underwriting compensation under the Securities Act. The letter of transmittal states that, by acknowledging that it will deliver a prospectus and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an “underwriter” within the meaning of the Securities Act. The letter of transmittal also states that any holder participating in this exchange offer will have no arrangements or understandings with any person to participate in the distribution of the original notes or the exchange notes within the meaning of the Securities Act. In addition, holders of original notes that tender their original notes in exchange for exchange notes must make the representations set forth in this prospectus under the heading “The Exchange Offer—Conditions to the Exchange Offer” and in the related letter of transmittal.

We have agreed to pay all expenses incident to the exchange offer, including all registration and filing fees and expenses (including filings made by any holder of original notes with the Financial Industry Regulatory Authority ("FINRA"), and, if applicable, the fees and expenses of any “qualified independent underwriter” and its counsel that may be required by the rules and regulations of FINRA), all fees and expenses of compliance with federal securities and state securities or blue sky laws, all expenses of printing, messenger and delivery services and telephone, all fees and disbursements of our legal counsel and, under certain circumstances, legal counsel for holders of original notes, and all fees and disbursements of our independent certified public accountants, and we will indemnify the holders of

the original notes (including any broker-dealers) against certain liabilities, including liabilities under the Securities Act.

LEGAL MATTERS

Vinson & Elkins L.L.P., Houston, Texas, has issued an opinion about the legality of the exchange notes.

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The consolidated and combined balance sheets of California Resources Corporation as of December 31, 2014 and 2013 and the related consolidated and combined statements of operations, comprehensive income, equity and cash flows for each of the years in the three-year period ended December 31, 2014, have been audited by KPMG LLP, independent registered public accounting firm, as stated in their report appearing elsewhere in this prospectus.

INDEPENDENT PETROLEUM ENGINEERS

Certain information included elsewhere in this prospectus with respect to the oil and gas reserves associated with California Resources Corporation’s oil and gas properties is confirmed in a methods and analytical procedures review letter of Ryder Scott & Company, independent petroleum engineers. We have included this information in reliance on the authority of such firm as an expert in these matters.

WHERE YOU CAN FIND MORE INFORMATION

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy documents filed by us with the SEC at the SEC’s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC’s website at www.sec.gov.

Our website is located at www.crc.com, and we make our periodic reports and other information filed with or furnished to the SEC available, free of charge, through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus.

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Report of Independent Registered Public Accounting Firm on Consolidated and Combined Financial Statements

To the Board of Directors and Stockholders
California Resources Corporation:

We have audited the accompanying consolidated and combined balance sheets of California Resources Corporation and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated and combined statements of operations, comprehensive income, equity and cash flows for each of the years in the three-year period ended December 31, 2014. These consolidated and combined financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated and combined financial statements based on our audits.

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

In our opinion, the consolidated and combined financial statements referred to above present fairly, in all material respects, the financial position of California Resources Corporation and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2014 in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Los Angeles, California
February 26, 2015

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CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated and Combined Balance Sheets
As of December 31, 2014 and 2013
(in millions)

	2014	2013
CURRENT ASSETS		
Cash and cash equivalents	\$ 14	\$ —
Trade receivables, net	308	30
Inventories	71	75
Other current assets	308	149
Total current assets	701	254
PROPERTY, PLANT AND EQUIPMENT	20,536	20,972
Accumulated depreciation, depletion and amortization	(8,851)	(6,964)
	11,685	14,008
OTHER ASSETS	111	35
TOTAL ASSETS	\$ 12,497	\$ 14,297
CURRENT LIABILITIES		
Accounts payable	\$ 588	\$ 448
Accrued liabilities	318	241
Total current liabilities	906	689
LONG-TERM DEBT	6,360	—

DEFERRED INCOME TAXES	2,055	3,122
OTHER LONG-TERM LIABILITIES	565	497
COMMITMENTS AND CONTINGENCIES		
EQUITY		
Preferred stock - no shares outstanding at December 31, 2014 or 2013 (200 million shares authorized at \$0.01 par value)		
Common stock (2.0 billion shares authorized at \$0.01 par value)		
Outstanding shares (2014 - 385,639,582 shares and 2013 - 0 shares)	4	—
Additional paid-in capital	4,748	—
Accumulated deficit	(2,117)	—
Net parent company investment	—	10,013
Accumulated other comprehensive income (loss)	(24)	(24)
Total Equity / Net Investment	2,611	9,989
TOTAL LIABILITIES AND EQUITY	\$ 12,497	\$ 14,297

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated and Combined Statements of Operations
For the years ended December 31, 2014, 2013 and 2012
(in millions)

	2014	2013	2012
REVENUES			
Oil and natural gas sales to related parties	\$ 2,617	\$ 4,054	\$ 3,878
Oil and natural gas sales to third parties	1,406	85	89
Other revenue	150	145	106
	4,173	4,284	4,073
COSTS AND OTHER DEDUCTIONS			
Production costs	1,023	960	1,219
Selling, general and administrative expenses	336	292	273
Depreciation, depletion and amortization	1,198	1,144	926
Asset impairments	3,402	—	29
Taxes other than on income	217	185	167
Exploration expense	139	116	148
Interest and debt expense, net	72	—	—
Other expenses	207	140	130

	6,594	2,837	2,892
INCOME / (LOSS) BEFORE INCOME TAXES	(2,421)	1,447	1,181
Income tax (expense) / benefit	987	(578)	(482)
NET INCOME / (LOSS)	<u><u>\$ (1,434)</u></u>	<u><u>\$ 869</u></u>	<u><u>\$ 699</u></u>
Net income / (loss) per share of common stock			
Basic	\$ (3.75)	\$ 2.24	\$ 1.80
Diluted	\$ (3.75)	\$ 2.24	\$ 1.80

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated and Combined Statements of Comprehensive Income
For the years ended December 31, 2014, 2013 and 2012
(in millions)

	2014	2013	2012
Net income / (loss)	<u><u>\$ (1,434)</u></u>	<u><u>\$ 869</u></u>	<u><u>\$ 699</u></u>
Other comprehensive income (loss) items:			
Unrealized (losses) gains on derivatives ^(a)	(2)	(2)	3
Pension and postretirement (losses) gains ^(b)	(1)	27	2
Reclassification to income of realized losses (gains) on derivatives ^(c)	3	(2)	—
Other comprehensive income, net of tax	<u><u>—</u></u>	<u><u>23</u></u>	<u><u>5</u></u>
Comprehensive income / (loss)	<u><u>\$ (1,434)</u></u>	<u><u>\$ 892</u></u>	<u><u>\$ 704</u></u>

(a) Net of tax of \$1, \$1 and \$(1) in 2014, 2013, and 2012, respectively.
(b) Net of tax of \$(1), \$(16) and \$(1) in 2014, 2013 and 2012, respectively. See Note 14, Retirement and Postretirement Benefit Plans, for additional information.
(c) Net of tax of \$(2), \$1 and zero in 2014, 2013 and 2012, respectively.

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated and Combined Statements of Equity
For the years ended December 31, 2014, 2013 and 2012
(in millions)

	Common Stock	Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Net Parent Company Investment	Total Equity/Net Investment
	(in millions)					
Balance, December 31, 2011	\$ —	\$ —	\$ —	\$ (52)	\$ 8,676	\$ 8,624
Net income / (loss)	—	—	—	—	699	699
Other comprehensive loss, net of tax	—	—	—	5	—	5
Net contributions from Occidental	—	—	—	—	532	532

Balance, December 31, 2012	\$	—	\$	—	\$	—	\$	(47)	\$	9,907	\$	9,860
Net income / (loss)		—		—		—		—		869		869
Other comprehensive income, net of tax		—		—		—		23		—		23
Net distributions to Occidental		—		—		—		—		(763)		(763)
Balance, December 31, 2013	\$	—	\$	—	\$	—	\$	(24)	\$	10,013	\$	9,989
Net income / (loss) ^(a)		—		—		(2,117)		—		683		(1,434)
Other comprehensive income, net of tax		—		—		—		—		—		—
Net contributions from Occidental ^(b)		—		—		—		—		56		56
Dividend to Occidental		—		—		—		—		(6,000)		(6,000)
Issuance of common stock at Spin-off		4		—		—		—		(4)		—
Reclassification of net parent company investment to additional paid-in capital		—		4,748		—		—		(4,748)		—
Balance, December 31, 2014	\$	4	\$	4,748	\$	(2,117)	\$	(24)	\$	—	\$	2,611

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

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

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

For the years ended December 31, 2014, 2013 and 2012
(in millions)

	2014	2013	2012
CASH FLOW FROM OPERATING ACTIVITIES			
Net income / (loss)	\$ (1,434)	\$ 869	\$ 699
Adjustments to reconcile net income / (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,198	1,144	926
Asset impairments	3,402	—	29
Deferred income tax expense / (benefit)	(1,152)	260	603
Other noncash charges to income	113	29	40
Dry hole expenses	101	72	128
Changes in operating assets and liabilities, net			
(Increase) decrease in trade receivables, net	146	(8)	20
(Increase) decrease in inventories	2	8	(23)
(Increase) decrease in other current assets	(133)	2	(49)
Increase (decrease) in accounts payable and other current liabilities	128	100	(150)
Net cash provided by operating activities	2,371	2,476	2,223
CASH FLOW FROM INVESTING ACTIVITIES			
Capital investments	(2,020)	(1,669)	(2,331)
Acquisitions and other	(292)	(44)	(424)
Net cash used by investing activities	(2,312)	(1,713)	(2,755)
CASH FLOW FROM FINANCING ACTIVITIES			
(Distributions to) contributions from Occidental, net	(335)	(763)	532
Dividends to Occidental	(6,000)	—	—
Issuance of senior notes	5,000	—	—
Issuance of term loan	1,000	—	—
Proceeds from revolving credit facility	515	—	—
Repayments of revolving credit facility	(155)	—	—
Debt issuance costs	(70)	—	—
Net cash (used) provided by financing activities	(45)	(763)	532
Increase in cash and cash equivalents	14	—	—
Cash and cash equivalents—beginning of year	—	—	—
Cash and cash equivalents—end of year	\$ 14	\$ —	\$ —

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES

Notes to Consolidated and Combined Financial Statements

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

The Separation and Spin-off

We are an independent oil and natural gas exploration and production company operating properties exclusively within the State of California. We were incorporated in Delaware as a wholly-owned subsidiary of Occidental Petroleum Corporation ("Occidental") on April 23, 2014, and remained a wholly-owned subsidiary of Occidental until the spin-off on November 30, 2014 (the "Spin-off"). Prior to the Spin-off, all material existing assets, operations and liabilities of the California business were consolidated under us. On November 30, 2014, Occidental distributed shares of our common stock on a pro rata basis to Occidental stockholders and we became an independent, publicly traded company. Occidental retained approximately 18.5% of our outstanding shares of common stock which it has stated it intends to divest within 18 months of the Spin-off.

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

Basis of Presentation

Up until the Spin-off, the accompanying consolidated and combined financial statements were derived from the consolidated financial statements and accounting records of Occidental. These consolidated and combined financial statements reflect the historical results of operations, financial position and cash flows of the California business. We account for our share of oil and gas exploration and production ventures, in which we have a direct working interest, by reporting our proportionate share of assets, liabilities, revenues, costs and cash flows within the relevant lines on the balance sheets and statements of income and cash flows.

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

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

All financial information presented after the Spin-off represents the financial position, results of operations and cash flows of CRC, as follows:

- Our consolidated and combined statements of operations, comprehensive income and cash flows for the year ended December 31, 2014 consist of the stand-alone consolidated results of CRC following the Spin-off, and the consolidated and combined results of the California business from January 1, 2014, through the Spin-off. Our statements of income, comprehensive income and cash flows for the years ended December 31, 2013 and 2012 consist entirely of the combined results of the California business.

- Our consolidated and combined balance sheet at December 31, 2014 consists of the consolidated balances of CRC, while at December 31, 2013, it consists of the combined balances of the California business.
- Our consolidated and combined statement of changes in equity for the year ended December 31, 2014 consists of both the California business prior to the Spin-off and the consolidated activity for CRC subsequent to the Spin-off. Our consolidated statement of changes in equity for the years ended December 31, 2013 and 2012 consist entirely of the combined activity of the California business.

Had we been a stand-alone company for the full year 2014, and had the same level of debt throughout the year as we did on December 31, 2014, of approximately \$6.4 billion, we would have incurred \$314 million pre-tax, or \$186 million after-tax, of interest expense, on a pro-forma basis, for the year ended December 31, 2014, compared to the \$72 million pre-tax interest expense reported in our statement of operations for the year then ended.

Certain prior year amounts have been reclassified to conform to the 2014 presentation.

Risks and Uncertainties

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

Revenue Recognition

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

Net Parent Company Investment

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

Inventories

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

Property, Plant and Equipment

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

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

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

	2014	2013	2012
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	(in millions)		
Balance - Beginning of Year	\$ 18	\$ 18	\$ 63
Additions to capitalized exploratory well costs pending the determination of proved reserves	3	46	62
Reclassification to property, plant and equipment based on the determination of proved reserves	(8)	(31)	(61)
Capitalized exploratory well costs charged to expense	(9)	(15)	(46)
Balance - End of Year	<u>\$ 4</u>	<u>\$ 18</u>	<u>\$ 18</u>

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

We determine depreciation and depletion of oil and gas producing properties by the unit-of-production method. We amortize acquisition costs over total proved reserves, and capitalized development and successful exploration costs over proved developed reserves. Substantially all of our total depreciation, depletion and amortization expense relates to production costs.

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

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

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

A portion of the carrying value of our oil and gas properties is attributable to unproved properties. At December 31, 2014, the net capitalized costs attributable to unproved properties were approximately \$300 million. The unproved amounts are not subject to DD&A until they are classified as proved properties. As exploration and development work progresses, if reserves on these properties are proved, capitalized costs attributable to the properties become subject to DD&A. If the exploration and development work were to be unsuccessful, or management decided not to pursue development of these properties as a result of lower commodity prices, higher development and operating costs, contractual conditions or other factors, the capitalized costs of the related properties would be expensed. The timing of any write-downs of these unproved properties, if warranted, depends upon management's plans, the nature, timing and extent of future exploration and development activities and their results. We recognize any impairment loss on unproved properties by providing a valuation allowance.

At year end 2014, we performed impairment tests with respect to our proved and unproved properties as a result of significant declines in oil prices largely during the last half of 2014. As a result, in the fourth quarter of 2014, we recorded pre-tax asset impairment charges of \$3.4 billion on proved and unproved properties throughout our asset base. The impairment charge was related to certain properties in the San Joaquin and Los Angeles basins and a portion of our assets in the Ventura basin, as well as our natural gas properties in the Sacramento basin. Approximately \$650 million of the charge

was related to unproved properties. The properties were impaired as a result of accounting rules that require us to evaluate our properties based on the year-end forward price curve, as well as projects we determined we would not pursue in the foreseeable future given the current environment.

In 2012, management decided not to pursue development of certain of our natural gas properties which were impacted by persistently low natural gas prices. As a result, we recorded an impairment charge in 2012 of \$29 million.

Asset Retirement Obligations

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

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

The following table summarizes the activity of the asset retirement obligation, of which \$397 million and \$388 million is included in other long-term liabilities, with the remaining current portion in accrued liabilities at December 31, 2014 and 2013, respectively.

	For the years ended December 31,	
	2014	2013
	(in millions)	
Beginning balance	\$ 415	\$ 387
Liabilities incurred - capitalized to PP&E	19	25
Liabilities settled and paid	(29)	(9)
Accretion expense	22	21
Acquisitions, disposition and other - changes in PP&E	26	(2)
Revisions to estimated cash flows - changes in PP&E	(34)	(7)
Ending balance	\$ 419	\$ 415

Derivative Instruments

Derivatives are carried at fair value and on a net basis when a legal right of offset exists with the same counterparty. Fair value gains and losses from derivative instruments are recognized in earnings in the current period and are reported on a net basis in the statements of operations. We apply hedge accounting when transactions meet specified criteria for hedge treatment and management elects and documents such treatment. For hedges, the gain or loss on the effective portion of the derivative is reported as a component of other comprehensive income (OCI) with an offsetting adjustment to the basis of the item being hedged. Realized gains or losses from hedges, and any ineffective portion, are recorded as a component of net sales in the statements of operations. Ineffectiveness is primarily created by a lack of correlation between the hedged item and the hedging instrument due to location, quality, grade or changes in the expected quantity of the hedged item.

A hedge is regarded as highly effective such that it qualifies for hedge accounting if, at inception and throughout its life, we expect that changes in the fair value or cash flows of the hedged item will be offset by 80 to 125 percent of the changes in the fair value or cash flows, respectively, of the hedging instrument. In the case of hedging a forecast transaction, the transaction must be probable and must present an exposure to variations in cash flows that could ultimately affect reported net income or loss. We discontinue hedge accounting when we determine that a derivative has ceased to be highly effective as a hedge; when the hedged item matures or is sold or repaid; or when a forecast transaction is no longer deemed probable.

Stock-based Incentive Plans

We have stockholder approved stock-based incentive plans for certain employees and directors that are more fully described in Note 11. A

summary of our accounting policy for awards issued under our plans is as follows.

The fair value of stock options granted to our employees is estimated on the date of grant using the Black-Scholes option pricing model. The model uses various assumptions, based on management's estimates at the time of grant, which impact the calculation of fair value and ultimately, the amount of expense recognized over the vesting period of the stock option award. Of the required assumptions, the expected life of the stock option award and the expected volatility of our stock price have the most significant impact on the fair value calculation. In the absence of adequate stock price history of CRC common stock, the volatility factor is based on the average volatilities of the stocks of a select group of peer companies, which are similar in nature to us. The average expected life is calculated based on the simplified method.

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

Earnings Per Share

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

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

Retirement and Postretirement Benefit Plans

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

For defined benefit pension and postretirement plans that are sponsored by us, we recognize the net overfunded or underfunded amounts in the financial statements using a December 31 measurement date.

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

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

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

Fair Value Measurements

We have categorized our assets and liabilities that are measured at fair value in a three-level fair value hierarchy, based on the inputs to the valuation techniques: Level 1—using quoted prices in active markets for the assets or liabilities; Level 2—using observable inputs other than quoted prices for the assets or liabilities; and Level 3—using unobservable inputs.

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

Commodity derivatives are carried at fair value. We utilize the mid-point between bid and ask prices for valuing these instruments. In addition to using market data in determining these fair values, we make assumptions about the risks inherent in the inputs to the valuation technique. Our commodity derivatives comprise Over-the-Counter (OTC) bilateral financial commodity contracts, which are generally valued using industry-standard models that consider various inputs, including quoted forward prices for commodities, time value, volatility factors, credit risk and current market and contracted prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable data or are supported by observable prices at which transactions are executed in the marketplace. We classify these measurements as Level 2.

The carrying amounts of on-balance-sheet financial instruments approximate fair value.

Other Current Assets

Other current assets at December 31, 2014 include amounts due from joint interest partners of approximately \$120 million, greenhouse gas emission credits of \$65 million and deferred tax assets of \$61 million. At December 31, 2013 other current assets included \$97 million due from joint interest partners.

Accrued Liabilities

Accrued liabilities at December 31, 2014 include accrued compensation-related costs of approximately \$80 million, interest payable of approximately \$70 million, and greenhouse gas liabilities of approximately \$65 million. At December 31, 2013 accrued liabilities included \$70 million of accrued compensation-related costs.

Supplemental Cash Flow Information

We have not made United States federal and state income tax payments directly to taxing jurisdictions. Up until the Spin-off, our share of Occidental's tax payments or refunds were paid or received, as applicable, by our parent and are reflected as part of the net parent company investment. Such amounts paid during the year ended December 31, 2014 and 2013 were approximately \$165 million and \$318 million, respectively, while the year ended December 31, 2012 resulted in a net refund of approximately \$121 million. We also paid taxes other than on income, consisting mostly of property taxes, of approximately \$183 million, \$185 million and \$171 million during the years ended December 31, 2014, 2013 and 2012, respectively. Interest paid totaled approximately \$3 million for the year ended December 31, 2014, and zero for each of the two years ended December 31, 2013 and 2012.

The 2014 capital investments reported on the statement of cash flows exclude changes to the consolidated balance sheets that did not affect cash primarily consisting of the increase in capital accruals during the year. Total capital investments in 2014 were \$2.089 billion, which included \$2.020 billion of cash paid for capital investments as reported in the statement of cash flows and \$69 million in increase in capital accruals. For the years 2013 and 2012, the changes in the capital accrual amounts were not material.

In 2014, Occidental transferred to us certain assets, liabilities and accruals, of which the most significant consisted of outstanding trade receivables of approximately \$400 million.

These non-cash transfers and the corresponding net contribution to us from Occidental were excluded from net cash provided by operating activities and cash flow from financing activities.

Major Customers

For the years ended December 31, 2014, 2013 and 2012, ConocoPhillips/Phillips 66 Company and Tesoro Refining & Marketing Company LLC each accounted for more than 10% of our net sales. Collectively, they accounted for 45%, 42% and 46% in each of those years, respectively.

Income Taxes

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

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. Deferred tax assets are recorded when it is more likely than not that they will be realized. The realization of deferred tax assets is assessed periodically based on several factors, including our expectation that we will generate sufficient future taxable income and reversals of taxable temporary differences.

NOTE 2 ACCOUNTING AND DISCLOSURE CHANGES

Recently Adopted Accounting and Disclosure Changes

In August 2014, the Financial Accounting Standards Board (FASB) issued rules relating to management’s responsibility to evaluate and make disclosures, if applicable, regarding the entity’s ability to continue as a going concern within one year after the date that the financial statements are issued. These rules are effective for annual periods ending after December 15, 2016. They are not expected to have a material impact on our financial statements upon adoption and will require assessment on an ongoing basis.

In June 2014, the FASB issued rules for employee share-based payment awards in which the terms of the awards provide that a performance target can be achieved after the requisite service period. A performance target that affects vesting and that could be achieved after the requisite service period will be treated as a performance condition. These rules are effective for annual periods beginning on or after December 15, 2015 and are not expected to have a material impact on our financial statements upon adoption but will require assessment on an ongoing basis.

In May 2014, the FASB issued rules related to revenue recognition. Under the new rules, an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects what it expects to receive in exchange for the goods or services. The rules will also require more detailed disclosures of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The rules are effective for interim and annual periods beginning after December 15, 2016 and early application is not permitted. While we are evaluating any potential impact of these new rules, we currently believe the effect of the new rules will not have a material impact on our financial statements.

In April 2014, the FASB issued rules changing the requirements for reporting discontinued operations such that only the disposals of components of an entity that represent a strategic shift that has (or will have) a major effect on an entity’s operations and financial results will be reported as discontinued operations in the financial statements. These rules are effective for the annual periods beginning on or after December 15, 2014. They are not expected to have a material impact on our financial statements upon adoption and will require assessment on an ongoing basis.

NOTE 3 ACQUISITIONS

2014

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

2013

During the year ended December 31, 2013, we paid approximately \$50 million to acquire certain oil and gas properties, including an acquisition in the San Joaquin basin, which obligates us to invest at least \$250 million on exploration and development activities over a period of five years from the date of acquisition. We currently plan to invest more than this amount during that period. Any deficiency in meeting this capital investment obligation would need to be paid in cash at the end of the five-year period. Through December 31, 2014, we have already fulfilled about 20% of this obligation.

2012

During the year ended December 31, 2012, we paid approximately \$380 million for oil and gas properties, including an acquisition for \$275 million for certain producing and non-producing assets in the Sacramento basin and undeveloped acreage in the San Joaquin basin.

NOTE 4 INVENTORIES

Inventories consisted of the following:

	Balance at December 31,	
	2014	2013
	(in millions)	
Materials and supplies	\$ 66	\$ 73
Finished goods	5	2
Total	\$ 71	\$ 75

NOTE 5 DEBT

Debt consisted of the following:

	December 31,	
	2014	2013
	(in millions)	
Revolving Credit Facility	\$ 360	\$ —
Term Loan Facility	1,000	—
5% notes due 2020	1,000	—
5 1/2% notes due 2021	1,750	—
6% notes due 2024	2,250	—
Total	\$ 6,360	\$ —

Credit Facilities

On September 24, 2014, we entered into a credit agreement with a syndicate of lenders, providing for (i) a five-year senior term loan facility (the "Term Loan Facility") and (ii) a five-year senior revolving loan facility (the "Revolving Credit Facility" and, together with the Term Loan Facility, the "Credit Facilities"). All borrowings under these facilities are subject to certain customary conditions. We amended the Credit Facilities effective as of February 25, 2015, and changed certain of our covenants through December 31, 2016 or such earlier time as we elect and demonstrate compliance with our original covenants for two successive quarters (the "Interim Covenant Period").

The aggregate initial commitments of the lenders under the Revolving Credit Facility are \$2.0 billion and under the Term Loan Facility are \$1.0 billion. The Revolving Credit Facility includes a sub-limit of \$400 million for the issuance of letters of credit. We will be required to repay the Term Loan Facility in equal quarterly installments equal to 2.5% (10.00% per annum) of the principal amount of the Term Loan Facility beginning on March 31, 2016. As of December 31, 2014, we had \$360 million outstanding under our Revolving Credit Facility with the ability to incur total net borrowings of up to \$1.25 billion during the Interim Covenant Period under this facility.

Borrowings under the Credit Facilities bear interest, at our election, at either a LIBOR rate or an alternate base rate ("ABR") (equal to the greatest of (i) the administrative agent's prime rate, (ii) the one-month LIBOR rate plus 1.00% and (iii) the federal funds effective rate plus 0.50%), in each case plus an applicable margin. This applicable margin is based on our most recent leverage ratio and will vary from (a) in the case of LIBOR loans, 1.50% to 2.25% and (b) in the case of ABR loans, from 0.50% to 1.25%. The unused portion of the Revolving Credit Facility is subject to commitment fees ranging from 0.30% to 0.50% per annum, based on our most recent leverage ratio. We also pay customary fees and expenses under the Revolving Credit Facility.

Interest payments under the Credit Facilities vary based on the borrowing options chosen. Interest on ABR loans is payable quarterly in arrears. Interest on LIBOR loans is payable at the end of each LIBOR period.

All obligations under the Credit Facilities are guaranteed jointly and severally by all of our wholly-owned material subsidiaries, and will be unsecured while we maintain our credit ratings at the minimum levels defined in the Credit Facilities. During the Interim Covenant Period, we would be required to grant security to our lenders if our corporate family ratings

experienced a two-notch decline from either of our rating agencies. Outside the Interim Covenant Period we would be required to grant security in the event of a three-notch decline subject to certain exceptions described in our Credit Facilities. The assets and liabilities of subsidiaries not

guaranteeing the debt are de minimis.

The Credit Facilities also require us to maintain the following financial covenants for the trailing twelve months ended as of the last day of each fiscal quarter: (a) a leverage ratio of no more than 4.50 to 1.00 except during the Interim Covenant Period when the ratio increases by varying amounts to a maximum of 8.25 to 1.00 by December 31, 2015 and (b) an interest expense ratio of no less than 2.50 to 1.00 except as of December 31, 2015 when the ratio must be no less than 2.25 to 1.00. In addition, during the Interim Covenant Period, we must maintain an asset coverage ratio of no less than 1.05 to 1.00 measured as of the last day of each fiscal quarter. Finally, during the Interim Covenant Period, we must apply cash on hand in excess of \$250 million to repay certain amounts outstanding under the Revolving Credit Facility. If we were to breach either of these covenants the banks would be permitted to accelerate the principal amount due under the facilities. If payment were accelerated it would result in a default under the notes.

Senior Notes

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

We will pay interest on the 2020 notes semi-annually in cash in arrears on January 15 and July 15 of each year, beginning on July 15, 2015. We will pay interest on the 2021 notes semi-annually in cash in arrears on March 15 and September 15 of each year, beginning on March 15, 2015. We will pay interest on the 2024 notes semi-annually in cash in arrears on May 15 and November 15 of each year, beginning on May 15, 2015.

In connection with the private placement of the notes, we granted the initial purchasers certain registration rights under a registration rights agreement.

The indenture governing the notes includes covenants that, among other things, limit our and our restricted subsidiaries' ability to incur debt secured by liens. These covenants also restrict our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. These covenants are subject to a number of important qualifications and limitations that are set forth in the indenture. The covenants are not, however, directly linked to measures of our financial performance. In addition, if we experience a "change of control triggering event" (as defined in the indenture) with respect to a series of notes, we will be required, unless we have exercised our right to redeem the notes of such series, to offer to purchase the notes of such series at a purchase price equal to 101 percent of their principal amount, plus accrued and unpaid interest.

Principal maturities of long-term debt outstanding at December 31, 2014 are as follows:

(in millions)

2015	\$	—
2016		100
2017		100
2018		100
2019		1,060
Thereafter		5,000
Total	\$	6,360

We estimate the fair value of fixed-rate debt based on prices from known market transactions for our instruments. The estimated fair value of our debt at December 31, 2014, the fixed rate portion of which was classified as Level 1, and the variable rate portion approximated fair value, was approximately \$5.6 billion, compared to a carrying value of approximately \$6.4 billion. A one-eighth percent change in the variable interest rates on the borrowings under our Term Loan Facility and Revolving Credit Facility on December 31, 2014, would result in an approximately \$1.7 million change in annual interest

expense. In 2014, we incurred \$70 million in debt issuance costs related to the notes and the Credit Facility which we amortize using the effective interest rate method over the respective term of each instrument.

As of December 31, 2014, we had letters of credit in the aggregate amount of approximately \$25 million that were issued to support ordinary

course marketing, regulatory and other matters.

NOTE 6 LEASE COMMITMENTS

We have entered into various operating lease agreements, mainly for office space, office equipment, and field equipment. We lease assets when leasing offers greater operating flexibility. Lease payments are generally expensed as part of production costs or selling, general and administrative expenses. At December 31, 2014, future net minimum lease payments for noncancelable operating leases (excluding oil and natural gas and other mineral leases, utilities, taxes, insurance and maintenance expense) totaled:

	Amount	
	(in millions)	
2015	\$	13
2016		14
2017		14
2018		14
2019		12
	Thereafter	58
Total minimum lease payments	\$	125

Rental expense for operating leases was \$10 million in 2014, \$11 million in 2013 and \$12 million in 2012.

NOTE 7 LAWSUITS, CLAIMS, COMMITMENTS AND CONTINGENCIES

We, or certain of our subsidiaries, are involved, in the normal course of business, in lawsuits, environmental and other claims and other contingencies that seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief. We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2014 and 2013 were not material to our balance sheets as of such dates. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We have certain commitments under contracts, including purchase commitments for goods and services. At December 31, 2014, total purchase obligations were approximately \$364 million, which included approximately \$70 million, \$47 million, \$32 million, \$186 million and \$18 million that will be paid in 2015, 2016, 2017, 2018 and 2019, respectively. Included in the purchase obligations are commitments for major fixed and determinable capital investments during 2015 and thereafter, which were approximately \$264 million.

We, our subsidiaries, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with the Spin-off, purchases and other transactions that they have entered into with us. These indemnities include indemnities made to Occidental against certain tax-related liabilities that may be incurred by Occidental relating to the Spin-off and liabilities related to operation of our business while it was still owned by Occidental. As of December 31, 2014, we are not aware of circumstances that we believe would reasonably be expected to lead to indemnity claims that would result in payments materially in excess of reserves.

NOTE 8 DERIVATIVES

In February 2015, we put into place additional hedging instruments to protect the pricing for almost two-thirds of our expected third quarter 2015 oil production. For this program we chose a combination of Brent-based collars (between \$55 and \$72) for 30,000 barrels per day for July through September as well as put options at \$50 per barrel Brent for 40,000 barrels per day in the same period. In addition, we sold a \$75 per barrel call for 30,000 barrels per day of oil production in March through June of 2015. Going forward as an independent company, we will continue to be strategic and opportunistic in implementing

any hedging program. Our objective is to protect against the cyclical nature of commodity prices to provide a level of certainty around our margins and cash flows necessary to implement our investment program.

In December 2014, we purchased put options, to hedge the risk associated with declining oil prices, for 100,000 barrels of crude oil production per day, effective on a monthly basis from January 1, 2015 through June 30, 2015. The strike price of the put option is \$50 tied to the Brent oil index. Changes in the intrinsic value of the put option are deferred in other comprehensive income/(loss) as a cash flow hedge until the hedged transactions are recognized in the statement of operations. Changes in the time value of the put option are marked to market through the statement of operations. The put option was valued using Level 2 inputs in the fair value hierarchy and was valued at approximately \$24 million in other current assets, as of December 31, 2014, which approximated the value of the instrument and the amount we paid the counterparty at the time the option was acquired.

We entered into financial swap agreements in November 2012 for the sale of a portion of our natural gas production. These swap agreements hedged 50 MMcf of natural gas per day beginning in January 2013 through March 2014 and qualified as cash-flow hedges. The weighted-average strike price of these swaps was \$4.30. The gross and net fair values of these derivatives as of December 31, 2013 were not material and were considered Level 2.

The after-tax gains and losses recognized in, and reclassified to income from, Accumulated Other Comprehensive Income (AOCI), for derivative instruments classified as cash-flow hedges for the years ended December 31, 2014, 2013 and 2012, and the ending AOCI balances for each period were not material. We recognized gains and losses reclassified to income in net sales. The amount of the ineffective portion of cash-flow hedges was immaterial for the years ended December 31, 2014, 2013 and 2012. Refer to Note 1 for our accounting policy on derivatives.

There were no fair value hedges as of and during the years ended December 31, 2014, 2013 and 2012.

NOTE 9 FAIR VALUE MEASUREMENTS

Fair Values - Recurring

The following table presents assets accounted for at fair value on a recurring basis as of December 31, 2014:

(in millions)	December 31, 2014				
	Level 1	Level 2	Level 3	Collateral	Total
Commodity derivative instruments, other current assets	—	24	—	—	24
Total	—	24	—	—	24

Commodity derivative instruments in Level 2 are over-the-counter put options for the first 100,000 barrels of crude oil production per day, effective on a monthly basis from January 1, 2015 through June 30, 2015, and are measured at fair value by using industry-standard models using various inputs, including quoted forward prices. We had no material assets or liabilities accounted for at fair value as of December 31, 2013.

Fair Values - Nonrecurring

At year end 2014, we performed impairment tests with respect to our proved and unproved properties as a result of significant declines in oil prices largely during the last half of 2014. We determined the carrying amounts of certain assets were not recoverable from future cash flows and, therefore, were impaired. As a result, in the fourth quarter of 2014, we recorded pre-tax asset impairment charges of \$3.4 billion, of which \$2.7 billion was for proved properties throughout our asset base to reduce these assets to their estimated fair values. The impairment charge was related to certain properties in the San Joaquin and Los Angeles basins and a portion of our assets in the Ventura basin, as well as our natural gas properties in the Sacramento basin.

The fair values of the proved properties held and used were determined as of the date of the assessment using discounted cash flow models based on management’s expectations for the future. Inputs included estimates of future oil and natural gas production, prices based on recent commodity forward price curves as of the date of the estimate, estimated operating and development costs, and a risk-adjusted discount rate of 10%.

Financial Instruments Fair Value

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

NOTE 10 INCOME TAXES

Income / (loss) before income taxes was (\$2,421) million, \$1,447 million and \$1,181 million for the years ended December 31, 2014, 2013 and 2012, respectively. The provision (benefit) for federal, state and local income taxes consists of the following:

For the years ended December 31,	United States	State	Total
	Federal	and Local	
	(in millions)		
2014			
Current	\$ 66	\$ 99	\$ 165
Deferred	(840)	(312)	(1,152)
	<u>\$ (774)</u>	<u>\$ (213)</u>	<u>\$ (987)</u>
2013			
Current	\$ 227	\$ 91	\$ 318
Deferred	222	38	260
	<u>\$ 449</u>	<u>\$ 129</u>	<u>\$ 578</u>
2012			
Current	\$ (140)	\$ 19	\$ (121)
Deferred	518	85	603
	<u>\$ 378</u>	<u>\$ 104</u>	<u>\$ 482</u>

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

	For the years ended December 31,		
	2014	2013	2012
United States federal statutory tax rate	35%	35%	35%
State income taxes, net of federal benefit	6	6	6
Other	—	(1)	—
Effective tax rate	<u>41%</u>	<u>40%</u>	<u>41%</u>

The tax effects of temporary differences resulting in deferred income taxes at December 31, 2014 and 2013 were as follows:

	2014		2013	
	Deferred Tax Assets	Deferred Tax Liabilities	Deferred Tax Assets	Deferred Tax Liabilities
	(in millions)			
Property, plant and equipment differences	\$ —	\$ (2,437)	\$ —	\$ (3,583)
Postretirement benefit accruals	39	—	14	—
Deferred compensation and benefits	62	—	60	—
Asset retirement obligations	184	—	182	—
Federal benefit of state income taxes	68	—	208	—
Net operating loss carryforwards	64	—	8	—

All other	27	(1)	14	(2)
Total deferred taxes	\$ 444	\$ (2,438)	\$ 486	\$ (3,585)

The current portion of deferred tax assets was \$61 million and \$23 million as of December 31, 2014 and 2013, respectively, which was reported in other current assets. The noncurrent portion of total deferred tax assets was reported net against deferred tax liabilities.

We evaluate our deferred tax assets to determine if a valuation allowance is required to reduce our deferred tax assets to an amount expected to be realized. We expect to realize our deferred tax assets through future taxable income and reversals of taxable temporary differences.

Due to the Spin-off on November 30, 2014, we will file short year U.S. federal and California income tax returns for the one month ended December 31, 2014. Prior to the Spin-off date, we were included in the Occidental income tax returns for all applicable years. There could be a settlement between us and Occidental under the tax sharing agreement related to income taxes for the periods prior to the Spin-off. The income tax provision was calculated as if we filed separate tax returns for all periods presented prior to the Spin-off. For the one-month period ended December 31, 2014, there is no current income tax provision and a \$1.5 billion deferred income tax benefit for U.S. federal and California taxes. As of December 31, 2014, an insignificant amount is due to Occidental under the tax sharing agreement. There were no amounts due to Occidental as of December 31, 2013.

We have no liabilities for unrecognized tax benefits as of December 31, 2014 and 2013. We believe there will not be material changes to our unrecognized tax benefits within the next 12 months. We recognize interest and penalties, if any, related to uncertain tax positions in the income tax provision. There were no amounts of interest and penalties related to uncertain tax positions during the years ended December 31, 2014, 2013 and 2012.

As of December 31, 2014, we had \$182 million of U.S. federal net operating losses and \$207 million of California net operating losses. The net operating loss carryforwards resulted from operations during the one-month ended December 31, 2014 and from the acquisition of a subsidiary in a prior year. The U.S. federal net operating losses begin expiring in 2017 and the California net operating losses begin expiring in 2015. Utilization of \$22 million of the U.S. federal and \$112 million of the California net operating loss carryforward is subject to an annual limitation as a result of these acquisitions and no financial statement benefit has been recognized for this portion of the net operating loss carryforward.

Our tax returns for the one-month period December 2014 will be subject to examination by U.S. federal and California tax authorities when filed. Under the tax sharing agreement, Occidental controls tax examinations for the periods in which we were included in a consolidated or combined income tax return filed by Occidental.

NOTE 11 STOCK COMPENSATION

General

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

Our incentive plan authorizes the Compensation Committee of our Board of Directors to grant up to a total of 25 million shares in the form of stock options, stock appreciation rights, stock awards, performance awards and cash awards, among others, to our employees, non-employee directors and other plan participants.

In connection with the Spin-off, unvested share-based compensation awards granted to our employees under Occidental's stock-based incentive plans and held by grantees as of November 30, 2014 were replaced with substitute awards based on CRC common shares. These substitute awards were intended to generally preserve the value of the original Occidental award determined as of November 30, 2014. Original and remaining vesting periods of Occidental awards were unaffected by the substitution. There were approximately 650 employees affected by the substitution of awards. The substitution of awards did not cause us to recognize incremental compensation expense. These substitute awards reduced the maximum number of shares of our common stock available for delivery under our incentive plan.

We expense all share-based payments to employees and non-employee directors based on the grant date fair value of the awards over the requisite service period, adjusted for estimated forfeitures.

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

Compensation expense for stock-based awards for the month ended December 31, 2014 was approximately \$1 million. Prior to the Spin-off, Occidental allocated certain costs to us which included compensation costs for stock-based awards of Occidental stock. If we were to estimate the equity compensation component of all costs allocated to us by Occidental using the same allocation method used by Occidental, stock compensation expense allocated to us was approximately \$26 million, \$33 million and \$20 million for January 1, 2014 through November 30, 2014, total year 2013, and total year 2012, respectively. Since these costs were allocated to us, it is not practical to calculate the tax benefit for those years.

As of December 31, 2014, unrecognized compensation expense for all our unvested stock-based incentive awards, based on the year end value of our common stock, was \$74 million. This expense is expected to be recognized over a weighted-average period of 2.3 years.

Restricted Stock Units

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

There were no CRC restricted stock units granted for the years ended December 31, 2013 or 2012. The following summarizes our restricted stock unit activity for the year ended December 31, 2014:

	Cash-Settled		Stock-Settled	
	RSUs (000's)	Weighted-Average Grant Date Fair Value	RSUs (000's)	Weighted-Average Grant-Date Fair Value
Unvested at December 31, 2013	—	\$ —	—	\$ —
Granted	4,562	\$ 7.37	6,663	\$ 7.84
Vested	—	\$ —	—	\$ —
Forfeited	(14)	\$ 7.37	—	\$ —
Unvested at December 31, 2014	4,548	\$ 7.37	6,663	\$ 7.84

Of the total awards granted, approximately 4,562,000 cash-settled units and 5,950,000 stock-settled units were substitute awards. The remainder were new awards granted following the Spin-off.

Stock Options

Following the Spin-off, we granted stock options to certain employees under our long-term incentive plan. The options permit purchase of our common stock at exercise prices no less than the fair market value of the stock on the date the options were granted. The options have terms of seven years and vest ratably, with one-third vesting and becoming exercisable on each anniversary date following the date of grant.

The fair value of each option 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 expected life of stock options is calculated based on the simplified method and represents the period of time that options granted are expected to be held prior to exercise. In the absence of adequate stock price history of CRC common stock, the volatility factor is based on the average volatilities of the stocks of a select group of

peer companies, which are similar in nature to us. The risk-free interest rate is the implied yield available on zero coupon (US Treasury Strip) T-notes at the grant date with a remaining term approximating the expected life. The dividend yield is the expected annual dividend yield over the expected life, expressed as a percentage of the stock price on the grant date. Estimates of fair value are not intended to predict actual future events

or the value ultimately realized by employees who receive stock-based incentive awards, and subsequent events may not be indicative of the reasonableness of the original estimates of fair value made by us.

The following table summarizes our option activity during the year ended December 31, 2014:

	Options (000's)	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Aggregate Intrinsic Value
Beginning balance, December 31, 2013	—	\$ —	\$ —	\$ —
Granted	8,481	8.11	1.98	—
Exercised	—	—	—	—
Forfeited	—	—	—	—
Expired or Canceled	—	—	—	—
Ending balance, December 31, 2014	8,481	\$ 8.11	\$ 1.98	\$ —

There were no CRC options granted for the years ended December 31, 2013 and 2012. There were no vested or exercisable options at December 31, 2014.

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

	2014
Exercise price per share	\$ 8.11
Expected life (in years)	4.5
Expected volatility	35.4%
Risk-free interest rate	1.4%
Dividend yield	0.5%
Grant date fair value of stock option awards granted	\$ 1.98

Employee Stock Purchase Plan

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

The maximum number of shares of our common stock which may be issued pursuant to the ESPP is subject to certain annual limits and has a cumulative limit of 5 million shares, subject to adjustment pursuant to the terms of the ESPP. As of January 1, 2015, about 45% of our employees have elected to participate in the plan.

NOTE 12 EQUITY

The following is a summary of common stock issuances:

	Common Stock (in 000's)
Balance, December 31, 2013	—
Issued	385,640
Balance, December 31, 2014	385,640

All stock issuances occurred in conjunction with the Spin-off. Approximately 3,537,000 shares consisted of CRC employee stock-based

incentive awards converted from Occidental awards and approximately 713,000 shares were for new CRC employee awards, all of which were unvested as of the Spin-off date.

Preferred Stock

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

ACCUMULATED OTHER COMPREHENSIVE INCOME / (LOSS)

Accumulated other comprehensive loss consisted of the following after-tax amounts:

	Balance at December 31,	
	2014	2013
	(in millions)	
Unrealized losses (gains) on derivatives	\$ —	\$ (1)
Pension and post-retirement adjustments ^(a)	(24)	(23)
Total	<u>\$ (24)</u>	<u>\$ (24)</u>

(a) See Note 14 for further information.

NOTE 13 EARNINGS PER SHARE

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

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

On December 1, 2014, the Spin-off date, 381.4 million shares of our common stock were distributed, of which approximately 18.5% was retained by Occidental. For comparative purposes, and to provide a more meaningful calculation of weighted-average shares outstanding, we have assumed this amount to be outstanding as of the beginning of each period prior to the Spin-off presented in the calculation of weighted-average shares. In addition, we have assumed the vested stock awards granted in December 2014 were also outstanding for each of the periods presented prior to the Spin-off, resulting in a weighted-average basic share count of 381.8 million shares. The effect of stock options granted in December 2014 was anti-dilutive.

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

	2014	2013	2012
	(in millions, except per-share amounts)		
Basic EPS calculation			
Net income / (loss)	\$ (1,434)	\$ 869	\$ 699
Net income / (loss) allocated to participating securities	—	(14)	(11)
Net income / (loss) available to common stockholders	<u>\$ (1,434)</u>	<u>\$ 855</u>	<u>\$ 688</u>
Weighted-average common shares outstanding - basic	<u>381.9</u>	<u>381.8</u>	<u>381.8</u>
Basic EPS	<u>\$ (3.75)</u>	<u>\$ 2.24</u>	<u>\$ 1.80</u>
Diluted EPS calculation			
Net income / (loss)	\$ (1,434)	\$ 869	\$ 699
Net income / (loss) allocated to participating securities	—	(14)	(11)

Net income / (loss) available to common stockholders	\$ (1,434)	\$ 855	\$ 688
Weighted average common shares outstanding - basic	381.9	381.8	381.8
Dilutive effect of potentially dilutive securities	—	—	—
Weighted-average common shares outstanding - diluted	381.9	381.8	381.8
Diluted EPS	\$ (3.75)	\$ 2.24	\$ 1.80

NOTE 14 RETIREMENT AND POSTRETIREMENT BENEFIT PLANS

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

Defined Contribution Plans

All of our employees were eligible to participate in one or more of the defined contribution retirement or savings plans that provide for periodic contributions by us, our subsidiaries or, prior to the Spin-off, by Occidental, based on plan-specific criteria, such as base pay, age, level and employee contributions. Certain salaried employees participated in a supplemental retirement plan that restored benefits lost due to governmental limitations on qualified retirement benefits. The accrued liabilities for the supplemental retirement plan were \$27 million and \$17 million as of December 31, 2014 and 2013, respectively, and we expensed \$29 million in 2014, \$34 million in 2013 and \$35 million in 2012 under the provisions of these defined contribution and supplemental retirement plans.

Defined Benefit Plans

Participation in defined benefit pension plans sponsored by us is limited. Approximately 260 employees, including union and certain nonunion employees who joined us from acquired operations with grandfathered benefits, are currently accruing benefits under these plans.

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

Postretirement and Other Benefit Plans

We provided postretirement medical and dental benefits and life insurance coverage for our employees and their eligible dependents through Occidental-sponsored plans prior to the Spin-off, and provide them through CRC-sponsored plans following the Spin-off. The benefits were generally funded as they were paid during the year. These benefit costs were approximately \$22 million in 2014, \$18 million in 2013 and \$17 million in 2012.

Obligations and Funded Status

The following tables show the amounts recognized in our balance sheets related to pension and postretirement benefit plans, including our share of obligations for Occidental-sponsored plans as well as plans that we or our subsidiaries sponsor, and their funding status, obligations and plan asset fair values (in millions):

	Pension Benefits		Postretirement Benefits	
	As of December 31,			
	2014	2013	2014	2013
Amounts recognized in the balance sheet:				
Accrued liabilities	\$ —	\$ —	\$ —	\$ (1)
Other long-term liabilities	(21)	(12)	(68)	(62)
	<u>\$ (21)</u>	<u>\$ (12)</u>	<u>\$ (68)</u>	<u>\$ (63)</u>

AOCI included the following after-tax balances:

Net loss	\$	22	\$	19	\$	2	\$	4
	Pension Benefits				Postretirement Benefits			
	2014		2013		2014		2013	
Changes in the benefit obligation:								
Benefit obligation—beginning of year	\$	103	\$	108	\$	63	\$	74
Service cost—benefits earned during the period		4		5		4		4
Interest cost on projected benefit obligation		4		3		2		3
Actuarial (gain) loss		6		(2)		(1)		(18)
Benefits paid		(9)		(11)		—		—
Benefit obligation—end of year	\$	108	\$	103	\$	68	\$	63
Changes in plan assets:								
Fair value of plan assets—beginning of year	\$	91	\$	74	\$	—	\$	—
Actual return on plan assets		5		13		—		—
Employer contributions		—		15		—		—
Benefits paid		(9)		(11)		—		—
Fair value of plan assets—end of year	\$	87	\$	91	\$	—	\$	—
(Unfunded) status:	\$	(21)	\$	(12)	\$	(68)	\$	(63)

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

	Accumulated Benefit Obligation in Excess of Plan Assets				Plan Assets in Excess of Accumulated Benefit Obligation			
	As of December 31,							
	2014		2013		2014		2013	
	(in millions)							
Projected Benefit Obligation	\$	31	\$	30	\$	77	\$	73
Accumulated Benefit Obligation	\$	26	\$	25	\$	62	\$	58
Fair Value of Plan Assets	\$	19	\$	23	\$	68	\$	68

We do not expect any plan assets to be returned during 2014.

COMPONENTS OF NET PERIODIC BENEFIT COST

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

	Pension Benefits			Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
	(in millions)					

Net periodic benefit costs:

Service cost—benefits earned during the period	\$	4	\$	5	\$	4	\$	4	\$	5	\$	4
Interest cost on projected benefit obligation		4		3		4		2		3		3
Expected return on plan assets		(6)		(4)		(4)		—		—		—
Recognized actuarial loss		2		4		4		1		2		2
Settlement cost		2		2		6		—		—		—
Net periodic benefit cost	\$	6	\$	10	\$	14	\$	7	\$	10	\$	9

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

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

	Pension Benefits	Postretirement Benefits		
	For the years ended December 31,			
	2014	2013	2014	2013
Benefit Obligation Assumptions:				
Discount rate	3.82%	4.45%	4.44%	4.75%
Rate of compensation increase	4.00%	4.00%	—	—
Net Periodic Benefit Cost Assumptions:				
Discount rate	4.45%	3.59%	4.75%	3.89%
Assumed long term rate of return on assets	6.50%	6.50%	—	—
Rate of compensation increase	4.00%	4.00%	—	—

For pension plans and postretirement benefit plans that we or our subsidiaries sponsor, we based the discount rate on the Aon/Hewitt AA Above Median yield curve in 2014 and the Aon/Hewitt AA-AAA Universe yield curve in 2013. 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 2014, we adopted the Society of Actuaries 2014 Mortality Tables Report and Mortality Improvement Scale, which updated the mortality assumptions that private defined benefit pension plans in the United States use in the actuarial valuations that determine a plan sponsor’s pension and postretirement obligations. The updated mortality data reflects increasing life expectancies in the United States, and affected plans generally expect the value of the actuarial obligations to increase, depending on the specific demographic characteristics of the plan participants and the types of benefits. The changes in the mortality assumptions resulted in an increase of \$2 million and \$7 million in the pension and postretirement benefit obligation, respectively, at December 31, 2014.

The postretirement benefit obligation was determined by application of the terms of medical and dental benefits and life insurance coverage, including the effect of established maximums on covered costs, together with relevant actuarial assumptions and healthcare cost trend rates projected at an assumed U.S. Consumer Price Index (CPI) increase of 1.79% and 2.36% as of December 31, 2014 and 2013, respectively. Under the terms of our postretirement plans, participants other than certain union employees pay for all medical cost increases in excess of increases in the CPI. For those union employees, we projected that healthcare cost trend rates would decrease 0.25 percent per year from 7.75 percent in 2014 until they reach

5.0% in 2025, and remain at 5.0% thereafter. A 1-percent increase or a 1-percent decrease in these assumed healthcare cost trend rates would result in an increase of \$6 million or a reduction of \$5 million, respectively, in the postretirement benefit obligation as of December 31, 2014. The annual service and interest costs would not be materially affected by these changes.

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

Fair Value of Pension Plan Assets

We employ a total return investment approach that uses a diversified blend of equity and fixed-income investments to optimize the long-term return of plan assets at a prudent level of risk. The investments were monitored by Occidental's Investment Committee in its role as fiduciary through November 30, 2014, and by our Investment Committee thereafter. Equity investments were diversified across United States and non-United States stocks, as well as differing styles and market capitalizations. Other asset classes, such as private equity and real estate, may have been used with the goals of enhancing long-term returns and improving portfolio diversification. The target allocation of plan assets was 65% equity securities and 35% debt securities. Investment performance was measured and monitored on an ongoing basis through quarterly investment portfolio and manager guideline compliance reviews, annual liability measurements and periodic studies.

The fair values of our pension plan assets by asset category are as follows (in millions):

	Fair Value Measurements at December 31, 2014 Using			
	Level 1	Level 2	Level 3	Total
Asset Class:				
Commingled funds:				
Fixed income	\$ —	\$ 20	\$ —	\$ 20
U.S. equity	—	31	—	31
International equity	—	17	—	17
Mutual funds:				
Bond funds	5	—	—	5
Blend funds	2	—	—	2
Value funds	2	—	—	2
Growth funds	3	—	—	3
Guaranteed deposit account	—	—	7	7
Total pension plan assets	\$ 12	\$ 68	\$ 7	\$ 87
	Fair Value Measurements at December 31, 2013 Using			
	Level 1	Level 2	Level 3	Total
Asset Class:				
Master trust investment account ^(a)	\$ —	\$ 69	\$ —	\$ 69
Mutual funds:				
Bond funds	5	—	—	5
Blend funds	3	—	—	3
Value funds	3	—	—	3
Growth funds	3	—	—	3
Guaranteed deposit account	—	—	9	9
Total pension plan assets ^(b)	\$ 14	\$ 69	\$ 9	\$ 92

(a) Represents our investment in a master trust investment account established by Occidental. The trust investments include common stock, preferred stock, publicly registered mutual funds, U.S. government securities and corporate bonds.

(b) Amounts exclude net payables of approximately \$1 million.

The activity during the years ended December 31, 2014 and 2013, for the assets using Level 3 fair value measurements was insignificant. We expect to contribute \$3 million to our defined benefit pension plans during 2015.

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

For the years ended December 31,	Pension Benefits	Postretirement Benefits	
	(in millions)		
2015	\$	15	\$ —
2016	\$	9	\$ 1
2017	\$	8	\$ 1
2018	\$	10	\$ 2
2019	\$	9	\$ 2
2020 - 2024	\$	44	\$ 17

NOTE 15 RELATED-PARTY TRANSACTIONS

During 2014, 2013 and 2012, we entered into the following related-party transactions:

	2014	2013	2012
	(in millions)		
Sales ^(a)	\$ 2,706	\$ 4,174	\$ 3,970
Allocated costs for services provided by affiliates	\$ 126	\$ 146	\$ 129
Purchases	\$ 175	\$ 164	\$ 119

(a) Amounts include related-party sales from our Elk Hills power plant of \$89 million, \$120 million and \$92 million during 2014, 2013 and 2012, respectively. These sales are included in other revenue in the statements of operations.

Through July 2014, substantially all of our products were sold through Occidental's marketing subsidiaries at market prices and were settled at the time of sale to those entities. Beginning August 2014, we started marketing our own products directly to third parties. For the years ended December 31, 2014, 2013 and 2012, sales to Occidental subsidiaries accounted for approximately 65%, 97% and 97% of our net sales, respectively.

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

Purchases from related parties reflect products purchased at market prices from Occidental's subsidiaries and used in our operations. These purchases are included in production costs. There were no significant related-party receivable or payable balances at December 31, 2014, 2013 and 2012.

Quarterly Financial Data (Unaudited)

Quarter	2014				2013			
	First	Second	Third	Fourth	First	Second	Third	Fourth

	(in millions, except per share amounts)							
Revenues	\$ 1,121	\$ 1,140	\$ 1,092	\$ 820	\$ 1,047	\$ 1,051	\$ 1,107	\$ 1,079
Gross profit	\$ 865	\$ 878	\$ 830	\$ 577	\$ 812	\$ 813	\$ 863	\$ 836
Net income / (loss)(a)	\$ 223	\$ 246	\$ 188	\$ (2,091)	\$ 217	\$ 205	\$ 235	\$ 212
Net income / (loss) per share(b):								
Basic	\$ 0.57	\$ 0.63	\$ 0.48	\$ (5.47)	\$ 0.56	\$ 0.53	\$ 0.61	\$ 0.55
Diluted	\$ 0.57	\$ 0.63	\$ 0.48	\$ (5.47)	\$ 0.56	\$ 0.53	\$ 0.61	\$ 0.55

- (a) For the quarter ended December 31, 2014, amount includes after-tax non-cash charges consisting of \$2.0 billion of asset impairments, \$31 million of rig termination and other price-related costs, and \$33 million of Spin-off and transition related costs.
- (b) For comparative purposes, and to provide a more meaningful calculation for weighted-average shares, we assumed the shares distributed to Occidental stockholders in conjunction with the Spin-off were outstanding at the beginning of each period prior to the Spin-off.

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

The following tables set forth our net interests in quantities of proved developed and undeveloped reserves of oil (including condensate), natural gas liquids (NGLs) and natural gas and changes in such quantities. Reserves are stated net of applicable royalties. Estimated reserves include our economic interests under arrangements similar to production-sharing contracts (PSCs) relating to the Wilmington field in Long Beach. All of our proved reserves are located within the State of California.

Oil Reserves

	San Joaquin Basin	Los Angeles Basin ^(a)	Ventura Basin	Sacramento Basin	Total
	(in millions of barrels (MMBbl))				
PROVED DEVELOPED AND UNDEVELOPED RESERVES					
Balance at December 31, 2011	337	130	41	—	508
Revisions of previous estimates	(44)	1	(3)	—	(46)
Improved recovery	36	16	11	—	63
Extensions and discoveries	3	—	—	—	3
Purchases of proved reserves	1	—	—	—	1
Sales of proved reserves	—	—	—	—	—
Production	(21)	(9)	(2)	—	(32)
Balance at December 31, 2012	312	138	47	—	497
Revisions of previous estimates	(8)	3	(3)	—	(8)
Improved recovery	49	24	3	—	76
Extensions and discoveries	—	—	—	—	—
Purchases of proved reserves	—	—	—	—	—

Sales of proved reserves	—	—	—	—	—
Production	(21)	(10)	(2)	—	(33)
Balance at December 31, 2013	332	155	45	—	532
Revisions of previous estimates	(41)	8	(4)	—	(37)
Improved recovery	70	11	4	—	85
Extensions and discoveries	1	—	—	—	1
Purchases of proved reserves	1	—	5	—	6
Sales of proved reserves	—	—	—	—	—
Production	(23)	(11)	(2)	—	(36)
Balance at December 31, 2014	340	163	48	—	551
?	?	?	?	?	?
PROVED DEVELOPED RESERVES					
December 31, 2011	240	97	30	—	367
December 31, 2012	221	104	30	—	355
December 31, 2013	226	109	28	—	363
December 31, 2014^(b)	229	124	34	—	387
?	?	?	?	?	?
PROVED UNDEVELOPED RESERVES					
December 31, 2011	97	33	11	—	141
December 31, 2012	91	34	17	—	142
December 31, 2013	106	46	17	—	169
December 31, 2014	111	39	14	—	164

(a) Includes proved reserves related to economic arrangements similar to PSCs of 116 MMBbl, 102 MMBbl, 98 MMBbl and 92 MMBbl at December 31, 2014, 2013, 2012 and 2011, respectively.

(b) Approximately 11 percent of the proved developed reserves at December 31, 2014 are nonproducing.

NGLs Reserves

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
(in MMBbl)					
PROVED DEVELOPED AND UNDEVELOPED RESERVES					
Balance at December 31, 2011	66	—	2	—	68
Revisions of previous estimates	(14)	—	—	—	(14)
Improved recovery	12	—	1	—	13
Extensions and discoveries	—	—	—	—	—
Purchases of proved reserves	—	—	—	—	—
Sales of proved reserves	—	—	—	—	—
Production	(6)	—	—	—	(6)
Balance at December 31, 2012	58	—	3	—	61
Revisions of previous estimates	13	—	—	—	13
Improved recovery	4	—	—	—	4

Extensions and discoveries	—	—	—	—	—
Purchases of proved reserves	—	—	—	—	—
Sales of proved reserves	—	—	—	—	—
Production	(7)	—	—	—	(7)
Balance at December 31, 2013	68	—	3	—	71
Revisions of previous estimates	8	—	—	—	8
Improved recovery	13	—	—	—	13
Extensions and discoveries	—	—	—	—	—
Purchases of proved reserves	—	—	—	—	—
Sales of proved reserves	—	—	—	—	—
Production	(7)	—	—	—	(7)
Balance at December 31, 2014	82	—	3	—	85
?	?	?	?	?	?
?	?	?	?	?	?
PROVED DEVELOPED RESERVES					
December 31, 2011	42	—	2	—	44
December 31, 2012	42	—	1	—	43
December 31, 2013	47	—	1	—	48
December 31, 2014^(a)	62	—	2	—	64
PROVED UNDEVELOPED RESERVES					
December 31, 2011	24	—	—	—	24
December 31, 2012	16	—	2	—	18
December 31, 2013	21	—	2	—	23
December 31, 2014	20	—	1	—	21

(a) Approximately 5 percent of the proved developed reserves at December 31, 2014 are nonproducing.

Natural Gas Reserves

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
(in billions of cubic feet (Bcf))					
PROVED DEVELOPED AND UNDEVELOPED RESERVES					
Balance at December 31, 2011	810	24	34	48	916
Revisions of previous estimates	(150)	(6)	(3)	(9)	(168)
Improved recovery	100	1	9	1	111
Extensions and discoveries	6	—	—	6	12
Purchases of proved reserves	2	—	—	154	156
Sales of proved reserves	—	—	—	—	—
Production	(74)	(1)	(4)	(14)	(93)

Balance at December 31, 2012	694	18	36	186	934
Revisions of previous estimates	(4)	(4)	(1)	(38)	(47)
Improved recovery	47	3	2	—	52
Extensions and discoveries	—	—	—	—	—
Purchases of proved reserves	—	—	—	—	—
Sales of proved reserves	—	—	—	—	—
Production	(66)	(1)	(4)	(24)	(95)
Balance at December 31, 2013	671	16	33	124	844
Revisions of previous estimates	(91)	—	4	7	(80)
Improved recovery	107	—	2	5	114
Extensions and discoveries	—	—	—	—	—
Purchases of proved reserves	—	—	2	—	2
Sales of proved reserves	—	—	—	—	—
Production	(66)	—	(4)	(20)	(90)
Balance at December 31, 2014	621	16	37	116	790
?	?	?	?	?	?
?	?	?	?	?	?
PROVED DEVELOPED RESERVES					
December 31, 2011	550	18	29	48	645
December 31, 2012	475	13	26	154	668
December 31, 2013	455	9	22	117	603
December 31, 2014^(a)	458	11	28	110	607
PROVED UNDEVELOPED RESERVES					
December 31, 2011	260	6	5	—	271
December 31, 2012	219	5	10	32	266
December 31, 2013	216	7	11	7	241
December 31, 2014	163	5	9	6	183

(a) Approximately 9 percent of the proved developed reserves at December 31, 2014 are nonproducing.

Total Reserves

	San Joaquin Basin	Los Angeles Basin ^(b)	Ventura Basin	Sacramento Basin	Total
(in MMBoe ^(a))					
PROVED DEVELOPED AND UNDEVELOPED RESERVES					

Balance at December 31, 2011	537	134	52	6	729
Revisions of previous estimates	(83)	—	(4)	(1)	(88)
Improved recovery	65	16	13	—	94
Extensions and discoveries	5	—	1	1	7
Purchases of proved reserves	1	—	—	25	26
Sales of proved reserves	—	—	—	—	—
Production	(39)	(9)	(4)	(2)	(54)
Balance at December 31, 2012	486	141	58	29	714
Revisions of previous estimates	4	2	(3)	(6)	(3)
Improved recovery	61	25	3	—	89
Extensions and discoveries	—	—	—	—	—
Purchases of proved reserves	—	—	—	—	—
Sales of proved reserves	—	—	—	—	—
Production	(40)	(10)	(3)	(3)	(56)
Balance at December 31, 2013	511	158	55	20	744
Revisions of previous estimates	(48)	8	(3)	1	(42)
Improved recovery	101	11	4	1	117
Extensions and discoveries	1	—	—	—	1
Purchases of proved reserves	1	—	5	—	6
Sales of proved reserves	—	—	—	—	—
Production	(41)	(11)	(3)	(3)	(58)
Balance at December 31, 2014	525	166	58	19	768

PROVED DEVELOPED RESERVES

December 31, 2011	372	99	40	6	517
December 31, 2012	341	105	38	24	508
December 31, 2013	349	110	35	20	514
December 31, 2014^(c)	367	126	41	18	552

PROVED UNDEVELOPED RESERVES

December 31, 2011	165	35	12	—	212
December 31, 2012	145	36	20	5	206
December 31, 2013	162	48	20	—	230
December 31, 2014	158	40	17	1	216

(a) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2014, the average prices of Brent oil and NYMEX natural gas were \$99.51 per Bbl and \$4.34 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 23 to 1.

(b) Includes proved reserves related to economic arrangements similar to PSCs of 116 MMBbl, 102 MMBbl, 98 MMBbl and 92 MMBbl at December 31, 2014, 2013, 2012 and 2011, respectively.

(c) Approximately 10 percent of the proved developed reserves at December 31, 2014 are nonproducing.

Capitalized Costs

Capitalized costs relating to oil and gas producing activities and related accumulated DD&A were as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
	(in millions)				
December 31, 2014					
Proved properties	\$ 15,362	\$ 1,982	\$ 1,353	\$ 326	\$ 19,023
Unproved properties	469	106	113	323	1,011
Total capitalized costs ^(a)	15,831	2,088	1,466	649	20,034
Accumulated depreciation, depletion and amortization ^(b)	(6,846)	(826)	(495)	(497)	(8,664)
Net capitalized costs	\$ 8,985	\$ 1,262	\$ 971	\$ 152	\$ 11,370
December 31, 2013					
Proved properties	\$ 15,120	\$ 2,487	\$ 1,479	\$ 542	\$ 19,628
Unproved properties	589	105	95	110	899
Total capitalized costs ^(a)	15,709	2,592	1,574	652	20,527
Accumulated depreciation, depletion and amortization ^(b)	(5,764)	(571)	(346)	(146)	(6,827)
Net capitalized costs	\$ 9,945	\$ 2,021	\$ 1,228	\$ 506	\$ 13,700
December 31, 2012					
Proved properties	\$ 14,359	\$ 1,974	\$ 1,327	\$ 286	\$ 17,946
Unproved properties	650	97	96	97	940
Total capitalized costs ^(a)	15,009	2,071	1,423	383	18,886
Accumulated depreciation, depletion and amortization ^(b)	(4,905)	(424)	(276)	(95)	(5,700)
Net capitalized costs	\$ 10,104	\$ 1,647	\$ 1,147	\$ 288	\$ 13,186
(a) Includes acquisition costs, development costs and asset retirement obligations.					
(b) Includes accumulated valuation allowance for total unproved properties of \$715 million, \$27 million and \$20 million at December 31, 2014, 2013 and 2012, respectively.					

Costs Incurred

Costs incurred includes capital investments, exploration (whether expensed or capitalized), acquisitions, and asset retirement obligations, as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
	(in millions)				
FOR THE YEAR ENDED DECEMBER 31, 2014					
Property acquisition costs					
Proved properties	\$ 79	\$ 3	\$ 128	\$ —	\$ 210

Unproved properties	21	—	81	—	102
Exploration costs	105	—	14	5	124
Development costs	1,356	495	99	12	1,962
Costs incurred	\$ 1,561	\$ 498	\$ 322	\$ 17	\$ 2,398

FOR THE YEAR ENDED DECEMBER 31, 2013

Property acquisition costs					
Proved properties	\$ 14	\$ 1	\$ —	\$ 5	\$ 20
Unproved properties	23	9	1	—	33
Exploration costs	127	—	1	3	131
Development costs	1,078	371	110	15	1,574
Costs incurred	\$ 1,242	\$ 381	\$ 112	\$ 23	\$ 1,758

FOR THE YEAR ENDED DECEMBER 31, 2012

Property acquisition costs					
Proved properties	\$ 83	\$ 8	\$ —	\$ 274	\$ 365
Unproved properties	30	1	—	10	41
Exploration costs	153	4	1	1	159
Development costs	1,721	348	124	26	2,219
Costs incurred	\$ 1,987	\$ 361	\$ 125	\$ 311	\$ 2,784

Results of Operations

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

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
(in millions)					
FOR THE YEAR ENDED DECEMBER 31, 2014					
Revenues ^(a)	\$ 2,735	\$ 956	\$ 244	\$ 88	\$ 4,023
Production costs ^(b)	579	330	89	25	1,023
General and administrative expenses ^(c)	76	42	11	11	140
Other operating expenses ^(d)	44	21	16	5	86
Depreciation, depletion and amortization	875	148	79	81	1,183
Taxes other than on income	140	49	8	6	203
Asset impairments ^(e)	1,266	1,110	437	589	3,402
Exploration expenses ^(f)	125	—	9	5	139
Pretax income	(370)	(744)	(405)	(634)	(2,153)
Income tax benefit	(151)	(304)	(165)	(259)	(879)
Results of operations	\$ (219)	\$ (440)	\$ (240)	\$ (375)	\$ (1,274)

FOR THE YEAR ENDED DECEMBER 31, 2013

Revenues(a)	\$ 2,823	\$ 968	\$ 259	\$ 89	\$ 4,139
Production costs(b)	552	306	75	27	960
General and administrative expenses	74	36	9	13	132
Other operating expenses	21	8	3	2	34
Depreciation, depletion and amortization	851	108	73	97	1,129
Taxes other than on income	109	43	9	10	171
Exploration expenses	94	1	13	8	116
Pretax income	1,122	466	77	(68)	1,597
Income tax expense / (benefit)	447	185	31	(27)	636
Results of operations	\$ 675	\$ 281	\$ 46	\$ (41)	\$ 961

FOR THE YEAR ENDED DECEMBER 31, 2012

Revenues(a)	\$ 2,738	\$ 921	\$ 262	\$ 46	\$ 3,967
Production costs(b)	790	331	81	17	1,219
General and administrative expenses	73	44	10	7	134
Other operating expenses(d)	26	—	2	2	30
Depreciation, depletion and amortization	724	79	61	44	908
Taxes other than on income	114	37	9	7	167
Asset impairments	19	10	—	—	29
Exploration expenses	112	29	1	6	148
Pretax income	880	391	98	(37)	1,332
Income tax expense / (benefit)	359	160	40	(15)	544
Results of operations	\$ 521	\$ 231	\$ 58	\$ (22)	\$ 788

- (a) Revenues are net of royalty payments.
- (b) Production costs are the costs incurred in lifting the oil and natural gas to the surface and include gathering, processing, field storage and insurance on proved properties, but do not include DD&A, royalties, income taxes and general and administrative expenses.
- (c) Includes unusual and infrequent costs related to Spin-off and transition related costs of \$6 million in total.
- (d) For 2014, the total amounts include unusual and infrequent costs related to rig termination charges and Spin-off and transition related costs totaling \$55 million. For 2012, the total amounts include rig termination charges of \$12 million.
- (e) At year end 2014, we recorded pre-tax asset impairment charges of \$3.4 billion on certain proved and unproved properties in the San Joaquin, Los Angeles, Ventura and Sacramento basins.
- (f) Includes \$21 million of unusual and infrequent costs related to dry holes and seismic charges.

Results per Unit of Production

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
(in millions)					
FOR THE YEAR ENDED DECEMBER 31, 2014					
Revenue from each barrel of oil equivalent (\$/Boe)(a)(b)	\$ 67.32	\$ 88.96	\$ 75.73	\$ 26.11	\$ 69.40
Production costs	14.24	30.71	27.62	7.42	17.64
General and administrative expenses	1.87	3.91	3.41	3.26	2.41
Other operating expenses	1.13	1.95	4.97	1.48	1.52
Depreciation, depletion and amortization	21.52	13.77	24.52	24.04	20.40
Taxes other than on income	3.44	4.56	2.48	1.78	3.50

Asset impairments ^(c)	31.14	103.29	135.63	174.78	58.66
Exploration expenses	3.07	—	2.79	1.48	2.40
Pretax income	(9.09)	(69.23)	(125.69)	(188.13)	(37.13)
Income tax benefit	(3.71)	(28.29)	(51.21)	(76.85)	(15.16)
Results of operations	<u>\$ (5.38)</u>	<u>\$ (40.94)</u>	<u>\$ (74.48)</u>	<u>\$ (111.28)</u>	<u>\$ (21.97)</u>

FOR THE YEAR ENDED DECEMBER 31, 2013

Revenue from each barrel of oil equivalent (\$/Boe) ^{(a)(b)}	\$ 71.86	\$ 101.17	\$ 79.28	\$ 22.09	\$ 73.72
Production costs	14.05	31.98	22.96	6.70	17.10
General and administrative expenses	1.88	3.76	2.75	3.23	2.35
Other operating expenses	0.53	0.83	0.92	0.50	0.60
Depreciation, depletion and amortization	21.66	11.29	22.34	24.08	20.11
Taxes other than on income	2.77	4.49	2.75	2.48	3.05
Exploration expenses	2.39	0.10	3.98	1.99	2.07
Pretax income	28.58	48.72	23.58	(16.89)	28.44
Income tax expense / (benefit)	11.38	19.34	9.49	(6.70)	11.33
Results of operations	<u>\$ 17.20</u>	<u>\$ 29.38</u>	<u>\$ 14.09</u>	<u>\$ (10.19)</u>	<u>\$ 17.11</u>

FOR THE YEAR ENDED DECEMBER 31, 2012

Revenue from each barrel of oil equivalent (\$/Boe) ^{(a)(b)}	\$ 69.30	\$ 102.45	\$ 81.85	\$ 20.09	\$ 73.48
Production costs	20.00	36.82	25.30	7.42	22.58
General and administrative expenses	1.85	4.89	3.12	3.06	2.48
Other operating expenses	0.66	—	0.62	0.88	0.56
Depreciation, depletion and amortization	18.33	8.79	19.06	19.21	16.82
Taxes other than on income	2.89	4.12	2.81	3.06	3.09
Asset impairments	0.48	1.11	—	—	0.54
Exploration expenses	2.83	3.23	0.31	2.62	2.74
Pretax income	22.26	43.49	30.63	(16.16)	24.67
Income tax expense / (benefit)	9.09	17.80	12.50	(6.55)	10.08
Results of operations	<u>\$ 13.17</u>	<u>\$ 25.69</u>	<u>\$ 18.13</u>	<u>\$ (9.61)</u>	<u>\$ 14.59</u>

- (a) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2014, the average prices of Brent oil and NYMEX natural gas were \$99.51 per Bbl and \$4.34 per Mcf, respectively, resulting in an oil to gas price ratio of approximately 23 to 1.
- (b) Revenues are net of royalty payments.
- (c) At year end 2014, we recorded pre-tax asset impairment charges of \$3.4 billion on certain proved and unproved properties in the San Joaquin, Los Angeles, Ventura and Sacramento basins.

Standardized Measure, Including Year-to-Year Changes Therein, of Discounted Future Net Cash Flows

For purposes of the following disclosures, future cash flows were computed by applying to our proved oil and gas reserves the unweighted arithmetic average of the first-day-of-the-month price for each month within the years ended December 31, 2014, 2013 and 2012, respectively. The realized prices used to calculate future cash flows vary by producing area and market conditions. Future operating and capital costs were forecast using the current cost environment applied to expectations of future operating and development activities. Future income tax expenses were computed by applying, generally, year-end statutory tax rates (adjusted for permanent differences, tax credits and allowances) to the estimated

net future pre-tax cash flows, after allowing for the tax basis of the assets as of December 31, 2014. The discount was computed by application of a 10-percent discount factor. The calculations assumed the continuation of existing economic, operating and contractual conditions at December 31, 2014, 2013 and 2012. Such assumptions, which are prescribed by regulation, have not always proven accurate in the past. Other valid assumptions would give rise to substantially different results.

Standardized Measure of Discounted Future Net Cash Flows

	Total
	(in millions)
AT DECEMBER 31, 2014	
Future cash inflows	\$ 59,709
Future costs	
Production costs ^(a)	(22,906)
Development costs ^(b)	(4,858)
Future income tax expense	(10,322)
Future net cash flows	21,623
Ten percent discount factor	(10,795)
Standardized measure of discounted future net cash flows	\$ 10,828
AT DECEMBER 31, 2013	
Future cash inflows	\$ 60,884
Future costs	
Production costs ^(a)	(29,523)
Development costs ^(b)	(6,327)
Future income tax expense	(8,213)
Future net cash flows	16,821
Ten percent discount factor	(7,598)
Standardized measure of discounted future net cash flows	\$ 9,223
AT DECEMBER 31, 2012	
Future cash inflows	\$ 57,468
Future costs	
Production costs ^(a)	(26,968)
Development costs ^(b)	(5,961)
Future income tax expense	(8,059)
Future net cash flows	16,480
Ten percent discount factor	(7,407)
Standardized measure of discounted future net cash flows	\$ 9,073

(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,		
	2014	2013	2012
	(in millions)		
Beginning of year	\$ 9,223	\$ 9,073	\$ 10,347
Sales and transfers of oil and natural gas produced, net of production costs and other operating expenses	(2,658)	(3,082)	(2,695)
Net change in prices received per Bbl, net of production costs and other operating expenses	567	575	(1,431)
Extensions, discoveries and improved recovery, net of future production and development costs	2,593	1,914	1,897
Change in estimated future development costs	75	(688)	(1,526)
Revisions of quantity estimates	(925)	(62)	(1,405)
Previously estimated development costs incurred during the period	1,440	1,185	1,039
Accretion of discount	1,324	1,292	1,512
Net change in income taxes	(468)	(95)	984
Purchases and sales of reserves in place, net	125	4	221
Changes in production rates and other	(468)	(893)	130
Net change	1,605	150	(1,274)
End of year	\$ 10,828	\$ 9,223	\$ 9,073

Oil, NGLs and Natural Gas Production Per Day

The following table set forth the production volumes of oil, NGLs and natural gas per day for each of the three years in the period ended December 31, 2014.

	2014	2013	2012
Oil (MBbl/d)			
San Joaquin Basin ^(b)	64	58	58
Los Angeles Basin ^(c)	29	26	24
Ventura Basin	6	6	6
Sacramento Basin	—	—	—
Total	99	90	88
?		?	?
NGLs (MBbl/d)			
San Joaquin Basin ^(b)	18	19	16
Los Angeles Basin	—	—	—
Ventura Basin	1	1	1
Sacramento Basin	—	—	—
Total	19	20	17
?	?	?	?
Natural gas (MMcf/d)			
San Joaquin Basin ^(b)	180	182	204
Los Angeles Basin ^(c)	1	2	3
Ventura Basin	11	11	12
Sacramento Basin	54	65	37

Total	246	260	256
Total Production (MBoe/d)^(a)	159	154	148

- (a) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2014, the average prices of Brent oil and NYMEX natural gas were \$99.51 per Bbl and \$4.34 per Mcf, respectively, resulting in an oil to gas price ratio of approximately 23 to 1.
- (b) Includes daily production from Elk Hills field of 25 MBbl oil, 16 MBbl NGLs and 136 MMcf natural gas in 2014; 26 MBbl oil, 18 MBbl NGLs and 145 MMcf natural gas in 2013; and 29 MBbl oil, 15 MBbl NGLs and 168 MMcf natural gas in 2012.
- (c) Includes daily production from Wilmington field of 25 MBbl Oil in 2014; 22 MBbl Oil in 2013; and 21 MBbl Oil in 2012.

California Resources Corporation



**Offer to Exchange up to
\$1,000,000,000 Principal Amount Outstanding of 5% Senior Notes due 2020,
\$1,750,000,000 Principal Amount Outstanding of 5 1/2% Senior Notes due 2021,
\$2,250,000,000 Principal Amount Outstanding of 6% Senior Notes due 2024 and
That Have Not Been Registered Under
The Securities Act of 1933**

For

**\$1,000,000,000 Principal Amount Outstanding of 5% Senior Notes due 2020,
\$1,750,000,000 Principal Amount Outstanding of 5 1/2% Senior Notes due 2021,
\$2,250,000,000 Principal Amount Outstanding of 6% Senior Notes due 2024 and
That Have Been Registered Under
The Securities Act of 1933**

**This Exchange Offer will expire at 5:00 p.m.,
New York City time, on April 28, 2015, unless extended.**

Each broker-dealer that receives exchange notes pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of exchange notes. The letter of transmittal states that by so acknowledging and by delivering a prospectus, such broker-dealer will not be deemed to admit that it is an “underwriter” within the meaning of the Securities Act. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of the exchange notes received in exchange for original notes where such original notes were acquired by such broker-dealer as a result of market-making activities or other trading activities. Until the earlier of (i) September 27, 2015 and (ii) the date on which broker-dealers are no longer required to deliver a prospectus in connection with the market-making or other trading activities, all dealers that effect transactions in the exchange notes, whether or not participating in this exchange offer, may be required to deliver a prospectus. This is in addition to the dealers’ obligation to deliver a prospectus when acting as underwriters with respect to their unsold allotments or subscriptions. We have agreed that, at any time before September 27, 2015 (or earlier as provided in the foregoing sentence), we will make this prospectus available to any broker-dealer for use in connection with any such resale. See “The Exchange Offer—Purpose and Effects of the Exchange Offer” and “Plan of Distribution.”

Annex A
CALIFORNIA RESOURCES CORPORATION
LETTER OF TRANSMITTAL

for Offer to Exchange up to
\$1,000,000,000 Principal Amount Outstanding of 5% Senior Notes due 2020,
\$1,750,000,000 Principal Amount Outstanding of 5½% Senior Notes due 2021, and
\$2,250,000,000 Principal Amount Outstanding of 6% Senior Notes due 2024
That Have Not Been Registered Under
The Securities Act of 1933
For
\$1,000,000,000 Principal Amount Outstanding of 5% Senior Notes due 2020,
\$1,750,000,000 Principal Amount Outstanding of 5½% Senior Notes due 2021, and
\$2,250,000,000 Principal Amount Outstanding of 6% Senior Notes due 2024
That Have Been Registered Under
The Securities Act of 1933

PURSUANT TO THE EXCHANGE OFFER AND PROSPECTUS

DATED March 31, 2015

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The Exchange Offer will expire at 5:00 p.m., New York City time, on April 28, 2015 (such date and time, as it may be extended by the issuer, the “Expiration Date”). Outstanding notes tendered in the Exchange Offer may be withdrawn at any time prior to 5:00 p.m., New York City time, on the Expiration Date, but not thereafter.

Delivery by Registered or Certified Mail:
Wells Fargo Bank, NA
Corporate Trust Operations
P.O. Box 1517
Minneapolis, MN 55480-1517

Regular Mail or Overnight Courier:
Wells Fargo Bank, NA
Corporate Trust Operations
N9303-121
6th & Marquette Avenue
Minneapolis, MN 55479

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In Person by Hand Only:
Wells Fargo Bank, NA
Northstar East Building
608 2nd Avenue South, 12th Floor
Minneapolis, MN 55402
For Information or Confirmation by Telephone:
(800) 344-5128

The undersigned hereby acknowledges receipt of the prospectus dated March 31, 2015 (the “Prospectus”) of California Resources Corporation (the “Issuer”) and this letter of transmittal (this “Letter of Transmittal”), which together constitute the offer by the Issuer to exchange its 5% Senior Notes due 2020 (the “2020 Exchange Notes”), 5½% Senior Notes due 2021 (the “2021 Exchange Notes”) and 6% Senior Notes due 2024 (the “2024 Exchange Notes”) or collectively, the “Exchange Notes,” the issuance of which has been registered under the Securities Act of 1933, as amended (the “Securities Act”), for a like principal amount of its issued and outstanding unregistered 5% Senior Notes due 2020 (the “2020 Original Notes”), 5½% Senior Notes due 2021 (the “2021 Original Notes”) and 6% Senior Notes due 2024 (the “2024 Original Notes”) or collectively, the “Original Notes.” The offer to exchange the Original Notes for the Exchange Notes is referred to as the “Exchange Offer.” Capitalized terms used but not defined herein shall have the respective meanings given to such terms in the Prospectus.

The Issuer reserves the right, at any time or from time to time, to extend the period of time during which the Exchange Offer for the Original Notes is open, at its discretion, in which event the term “Expiration Date” shall mean the latest date to which the Exchange Offer is extended. The Issuer shall notify Wells Fargo Bank, National Association (the “Exchange Agent”) of any extension by oral or written notice and shall make a public announcement thereof no later than 9:00 a.m., New York City time, on the next business day after the previously scheduled Expiration Date.

This Letter of Transmittal is to be used by a holder of Original Notes. Tender of the Original Notes is to be made according to the Automated Tender Offer Program (“ATOP”) of the Depository Trust Company (“DTC”) pursuant to the procedures set forth in the Prospectus under the caption “The Exchange Offer-Procedures for Tendering Original Notes.” DTC participants that are accepting the Exchange Offer must transmit their acceptance to DTC, which will verify the acceptance and execute a book-entry delivery to the Exchange Agent’s DTC account. DTC will then send a computer-generated message known as an “agent’s message” to the exchange agent for its acceptance. For you to validly tender your Original Notes in the Exchange Offer, the Exchange Agent must receive, prior to the Expiration Date, an agent’s message under the ATOP procedures that confirms that:

- DTC has received your instructions to tender your Original Notes; and
- You agree to be bound by the terms of this Letter of Transmittal.

BY USING THE ATOP PROCEDURES TO TENDER ORIGINAL NOTES, YOU WILL NOT BE REQUIRED TO DELIVER THIS LETTER OF TRANSMITTAL TO THE EXCHANGE AGENT. HOWEVER, YOU WILL BE BOUND BY ITS TERMS, AND YOU WILL BE DEEMED TO HAVE MADE THE ACKNOWLEDGMENTS AND THE REPRESENTATIONS AND WARRANTIES IT CONTAINS, JUST AS IF YOU HAD SIGNED IT.

PLEASE READ THE ACCOMPANYING INSTRUCTIONS CAREFULLY

Ladies and Gentlemen:

1. By tendering Original Notes in the Exchange Offer, you acknowledge receipt of the Prospectus and this Letter of Transmittal.

2. By tendering Original Notes in the Exchange Offer, you represent and warrant that you have (1) full authority to tender the Original Notes described above and in the Prospectus and will, upon request, execute and deliver any additional documents deemed by the Issuer to be necessary or desirable to complete the tender of Original Notes, (2) the Issuer will acquire good, marketable and unencumbered title to the tendered Original Notes, free and clear of all liens, restrictions, charges and other encumbrances, and (3) the Original Notes tendered hereby are not subject to any adverse claims or proxies.

3. The tender of the Original Notes pursuant to all of the procedures set forth in the Prospectus will constitute an agreement between you and the Issuer as to the terms and conditions set forth in the Prospectus.

4. You understand that by tendering Original Notes in the Exchange Offer, you acknowledge that the Exchange Offer is being made in reliance upon interpretations contained in no-action letters issued to third parties by the staff of the Securities and Exchange Commission (the "Commission"), including Exxon Capital Holdings Corp., Commission No-Action Letter (available May 13, 1988), Morgan Stanley & Co., Inc., Commission No-Action Letter (available June 5, 1991) and Shearman & Sterling, Commission No-Action Letter (available July 2, 1993), that the Exchange Notes issued in exchange for the Original Notes pursuant to the Exchange Offer may be offered for resale, resold and otherwise transferred by holders thereof (other than a broker-dealer who purchased Original Notes exchanged for such Exchange Notes directly from the Issuer to resell pursuant to Rule 144A or any other available exemption under the Securities Act of 1933, as amended (the "Securities Act") and any such holder that is an "affiliate" of the Issuer or of any of the subsidiary guarantors named in the Prospectus within the meaning of Rule 405 under the Securities Act), without compliance with the registration and prospectus delivery provisions of the Securities Act, provided that such Exchange Notes are acquired in the ordinary course of such holders' business and such holders are not participating in, and have no arrangement with any person to participate in, the distribution of such Exchange Notes.

5. By tendering Original Notes in the Exchange Offer, you represent and warrant that:

- a. the Exchange Notes acquired pursuant to the Exchange Offer are being obtained in the ordinary course of your business, whether or not you are the holder;
- b. neither you nor any such other person is engaging in or intends to engage in a distribution of such Exchange Notes;
- c. neither you nor any such other person has an arrangement or understanding with any person or entity to participate in the distribution of such Exchange Notes;
- d. neither you nor any such other person is an "affiliate," as such term is defined under Rule 405 promulgated under the Securities Act, of the Issuer, or of the subsidiary guarantors named in the Prospectus or, if you are an affiliate, that you will comply with the registration and prospectus delivery requirements of the Securities Act to the extent applicable; and
- e. if you are a broker-dealer that will receive Exchange Notes for your own account in exchange for Original Notes, you acquired those Original Notes as a result of market-making activities or other trading activities and you will deliver the Prospectus, as required by law, in connection with any resale of the Exchange Notes.

6. If you are a broker-dealer that will receive Exchange Notes for your own account in exchange for Original Notes that were acquired as a result of market-making activities or other trading activities, you acknowledge, by tendering Original Notes in the Exchange Offer, that you will deliver a prospectus in connection with any resale of such Exchange Notes; however, by so acknowledging and by delivering a prospectus, you will not be deemed to admit that you are an "underwriter" within the meaning of the Securities Act. If you are a broker-dealer and Original Notes held for your own account were not acquired as a result of market-making or other trading activities, such Original Notes cannot be exchanged pursuant to the Exchange Offer.

7. Any of your obligations hereunder shall be binding upon your successors, assigns, executors, administrators, trustees in bankruptcy and legal and personal representatives.

INSTRUCTIONS TO LETTER OF TRANSMITTAL

FORMING PART OF THE TERMS AND CONDITIONS OF THE EXCHANGE OFFER

1. Book-Entry Confirmations.

Any confirmation of a book-entry transfer to the Exchange Agent’s account at DTC of Original Notes tendered by book-entry transfer (a “Book-Entry Confirmation”), as well as an agent’s message, and any other documents required by this Letter of Transmittal, must be received by the Exchange Agent at its address set forth herein prior to 5:00 P.M. New York City time on the Expiration Date.

2. Partial Tenders.

Tenders of Original Notes will be accepted only in denominations of \$2,000 and integral multiples of \$1,000 in excess thereof. The entire principal amount of Original Notes delivered to the Exchange Agent will be deemed to have been tendered unless otherwise communicated to the Exchange Agent. If the entire principal amount of all Original Notes is not tendered, then Original Notes for the principal amount of Original Notes not tendered and Exchange Notes issued in exchange for any Original Notes accepted will be delivered to the holder via the facilities of DTC promptly after the Original Notes are accepted for Exchange.

3. Validity of Tenders.

All questions as to the validity, form, eligibility (including, time of receipt), acceptance and withdrawal of tendered Original Notes will be determined by the Issuer in its sole discretion, which determination will be conclusive, final and binding. The Issuer reserves the absolute right to reject any and all tenders not in proper form or any Original Notes the Issuer’s acceptance of which would, in the opinion of the Issuer’s counsel, be unlawful. The Issuer also reserve the right to waive any of the conditions of the Exchange Offer or any defect or irregularity in the tender of Original Notes. Unless waived, any defects or irregularities in connection with tenders of Original Notes must be cured within such time as the Issuer shall determine. The Issuer’s interpretation of the terms of the Exchange Offer (including this Letter of Transmittal and the instructions hereto) shall be conclusive, final and binding on all parties. Unless waived, any defects or irregularities in connection with tenders of Original Notes must be cured within such time as the Issuer shall determine. Although the Issuer intends to notify holders of defects or irregularities with respect to tenders of Original Notes through the Exchange Agent, neither the Issuer, the Exchange Agent nor any other person is under any duty to give such notice, nor shall they incur any liability for failure to give such notice. Tenders of Original Notes will not be deemed to have been made until such defects or irregularities have been waived by the Issuer or cured. Any Original Notes received by the Exchange Agent that are not properly tendered and as to which the defects or irregularities have not been cured or waived will be returned by the Exchange Agent to the tendering holders, unless otherwise provided in the Letter of Transmittal, promptly following the Execution Date.

4. Waiver of Conditions.

The Issuer in its sole discretion reserves the absolute right to waive, in whole or part, any of the conditions to the Exchange Offer set forth in the Prospectus or in this Letter of Transmittal.

5. No Conditional Tender.

No alternative, conditional or contingent tender of Original Notes will be accepted.

6. Requests for Assistance or Additional Copies.

Requests for assistance or for additional copies of the Prospectus or this Letter of Transmittal may be directed to the Exchange Agent at the address or telephone number set forth on the cover page of this Letter of

Transmittal. Holders may also contact their broker, dealer, commercial bank, trust company or other nominee for assistance concerning the Exchange Offer.

7. Withdrawal.

Tenders may be withdrawn only in accordance with the procedures set forth in the Prospectus under the caption “The Exchange Offer- Withdrawal of Tenders.”

8. No Guarantee of Late Delivery.

There is no procedure for guarantee of late delivery in the Exchange Offer.

IMPORTANT: BY USING THE ATOP PROCEDURES TO TENDER ORIGINAL NOTES, YOU WILL NOT BE REQUIRED TO DELIVER THIS LETTER OF TRANSMITTAL TO THE EXCHANGE AGENT. YOU WILL, HOWEVER, BE BOUND BY ITS TERMS, AND YOU WILL BE DEEMED TO HAVE MADE THE ACKNOWLEDGMENTS AND THE REPRESENTATIONS AND WARRANTIES IT CONTAINS.

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Annex B
Reconciliation of Non-GAAP Measures and Other Information

Core Income

The table below reconciles net income / (loss) to core income and lists unusual and infrequent items affecting earnings for the years ended December 31, 2014 and 2013 (in millions):

	2014	2013	2012
Net income / (loss)	\$ (1,434)	\$ 869	\$ 699
Unusual and infrequent items:			
Asset impairments	3,402	—	29
Rig terminations and other price-related costs	52	—	12
Spin-off and transition related costs	55	—	—
	<u>3,509</u>	<u>—</u>	<u>41</u>
Tax effect of pre-tax adjustments	(1,425)	—	17
Core income	<u>\$ 650</u>	<u>\$ 869</u>	<u>\$ 675</u>

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

EBITDAX

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

The following table presents a reconciliation of the non-GAAP financial measure of EBITDAX to the GAAP financial measure of net income for the years ended December 31, 2014 and 2013 (in millions):

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	2014	2013	2012
Net income / (loss)	\$ (1,434)	\$ 869	\$ 699
Interest expense	72	—	—
Income tax expense / (benefit)	(987)	578	482
Asset impairments	3,402	—	29
Depreciation, depletion and amortization	1,198	1,144	926
Exploration expense	139	116	148
Other non-cash items	51	26	—
Unusual and infrequent charges ^(a)	107	—	12
EBITDAX	<u>\$ 2,548</u>	<u>\$ 2,733</u>	<u>\$ 2,296</u>

(a) Includes rig terminations and other price-related costs, and Spin-off and transition related costs.
(b) The following table sets forth a reconciliation of the non-GAAP financial measure of EBITDAX to the GAAP measure of net cash provided by operating activities:

	2014	2013
Net cash provided by operating activities	\$ 2,371	\$ 2,476
Interest expense	72	—
Current income taxes	165	318
Cash exploration expenses	38	44
Changes in operating assets and liabilities	(143)	(103)
Other, net	45	(2)
EBITDAX	<u>\$ 2,548</u>	<u>\$ 2,733</u>

Reserve Replacement Ratio

The reserves replacement ratio is calculated for a specified period using the applicable proved oil-equivalent additions divided by oil-equivalent production. 76% of the additions are proved undeveloped. There is no guarantee that historical sources of reserves additions will continue as many factors fully or partially outside management's control, including the underlying geology, commodity prices and availability of capital, affect reserves additions. Management uses this measure to gauge results of its capital allocation. The measure is limited in that reserves may be added and produced based on costs incurred in separate periods and other oil and gas producers may use different replacement ratios affecting comparability.

Finding and Development Costs

Finding and development costs for the capital program are calculated by dividing the costs incurred from the capital program (development and exploration costs) by the amount of proved reserves added in the same year from improved recovery and extensions and discoveries (excluding acquisitions and revisions). Our management believes that reporting our finding and development costs can aid evaluation of our ability to add proved reserves at a reasonable cost and is not a substitute for our GAAP disclosures. Various factors, including timing differences and effects of commodity price changes, can cause finding and development costs to reflect costs associated with particular reserves imprecisely. For example, we will need to make more investments in order to develop the proved undeveloped reserves added during the year and any future revisions may change the actual measure from that presented above. Our calculations of finding and development costs may not be comparable to similar measures provided by other companies.

