SANDRIDGE ENERGY INC
Form 10-K
March 30, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark One)
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 001-33784
SANDRIDGE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20-8084793 (I.R.S. Employer Identification No.)
123 Robert S. Kerr Avenue Oklahoma City, Oklahoma (Address of principal executive offices)	73102 (Zip Code)

(405) 429-5500
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $0.001 par value	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No þ
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No þ
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o	Accelerated filer þ
Non-accelerated filer o (Do not check if smaller reporting company)	Smaller reporting company o

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2015 was approximately $447.7 million based on the closing price as quoted on the New York Stock Exchange. As of March 23, 2016, there were 718,226,053 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company’s definitive proxy statement for the 2016 Annual Meeting of Stockholders are incorporated by reference in Part III.

SANDRIDGE ENERGY, INC.
2015 ANNUAL REPORT ON FORM 10-K
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Certain Defined Terms

References in this report to the “Company” and “SandRidge” mean SandRidge Energy, Inc., including its consolidated subsidiaries and variable interest entities of which it is the primary beneficiary. In addition, this report includes terms commonly used in the oil and natural gas industry, which are defined in the “Glossary of Oil and Natural Gas Terms” beginning on page 26.

Information Regarding Forward-Looking Statements

Various statements contained in this report, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). These statements generally are accompanied by words that convey projected future events or outcomes. These forward-looking statements may include projections and estimates concerning the Company’s capital expenditures, liquidity, capital resources and debt profile, pending dispositions, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, elements of the Company’s business strategy, compliance with governmental regulation of the oil and natural gas industry, including environmental regulations, acquisitions and divestitures and the effects thereof on the Company’s financial condition and other statements concerning the Company’s operations, financial performance and financial condition. Forward-looking statements are generally accompanied by words such as “estimate,” “assume,” “target,” “project,” “predict,” “believe,” “expect,” “anticipate,” “potential,” “could,” “may,” “foresee,” “plan,” “goal,” “should,” “intend” or other words that uncertainty of future events or outcomes. The Company has based these forward-looking statements on its current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments as well as other factors the Company believes are appropriate under the circumstances. The actual results or developments anticipated may not be realized or, even if substantially realized, may not have the expected consequences to or effects on the Company’s business or results. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected in such forward-looking statements. These forward-looking statements speak only as of the date hereof. The Company disclaims any obligation to update or revise these forward-looking statements unless required by law, and it cautions readers not to rely on them unduly. While the Company’s management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks and uncertainties discussed in “Risk Factors” in Item 1A of this report, including the following:

- risks associated with drilling oil and natural gas wells;
- the volatility of oil, natural gas and natural gas liquids (“NGL”) prices;
- uncertainties in estimating oil, natural gas and NGL reserves;
- the need to replace the oil, natural gas and NGLs the Company produces;
- the Company’s ability to execute its growth strategy by drilling wells as planned;
- the amount, nature and timing of capital expenditures, including future development costs, required to develop the Company’s undeveloped areas;
- concentration of operations in the Mid-Continent region of the United States;
- risks associated with obligations to deliver minimum volumes of natural gas under long-term contracts, including the risk that the Company will incur significant monetary penalties for under-delivery;
- limitations of seismic data;
- the potential adverse effect of commodity price declines on the carrying value of the Company’s oil and natural properties;
- severe or unseasonable weather that may adversely affect production;

- availability of satisfactory oil, natural gas and NGL marketing and transportation;
- availability and terms of capital to fund capital expenditures;
- amount and timing of proceeds of asset monetizations;
- substantial existing indebtedness and limitations on operations resulting from debt restrictions and financial covenants;
- potential financial losses or earnings reductions from commodity derivatives;
- potential elimination or limitation of tax incentives;
- competition in the oil and natural gas industry;
- general economic conditions, either internationally or domestically or in the areas where the Company operates;

- costs to comply with current and future governmental regulation of the oil and natural gas industry, including environmental, health and safety laws and regulations, and regulations with respect to hydraulic fracturing and the disposal of produced water; and
- the need to maintain adequate internal control over financial reporting.

PART I

Item 1. Business

GENERAL

SandRidge Energy, Inc. is an energy company engaged in the exploration, development and production of crude oil, natural gas and NGLs. The Company's primary area of operation is the Mid-Continent in Oklahoma and Kansas. The Company owns and operates additional interests in west Texas and acquired properties located in the Rockies in Colorado in December 2015. Additionally, the Company owned interests in the Gulf of Mexico and Gulf Coast until February 2014, as discussed under "2014 Divestiture" below.

As of December 31, 2015, the Company had 4,411 gross (3,371.7 net) producing wells, a substantial portion of which it operates, and approximately 2,063,000 gross (1,476,000 net) total acres under lease. As of December 31, 2015, the Company had four rigs drilling in the Mid-Continent. Total estimated proved reserves as of December 31, 2015 were 324.6 MMBoe, of which approximately 80% were proved developed.

The Company also operates businesses and infrastructure systems that are complementary to its primary exploration and production activities, including gas gathering and processing facilities, marketing operations, a saltwater gathering and disposal system and an electrical transmission system. Additionally, until January 2016, the Company operated a drilling and related oilfield services business.

The Company's principal executive offices are located at 123 Robert S. Kerr Avenue, Oklahoma City, Oklahoma 73102 and the Company's telephone number is (405) 429-5500. SandRidge makes available free of charge on its website at www.sandridgeenergy.com its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after the Company electronically files such material with, or furnishes it to, the Securities and Exchange Commission ("SEC"). Any materials that the Company has filed with the SEC may be read and copied at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington D.C. 20549 or accessed via the SEC's website address at www.sec.gov.

Business Strategy

SandRidge's mission is to become a high-return, growth-oriented resource conversion company focused in the Mid-Continent and Rockies regions of the United States. In pursuit of its mission, the Company focuses on the following strategies:
Complementary Operating Areas. The Company's primary areas of operation are the Mid-Continent area of Oklahoma and Kansas and the Niobrara Shale in the Colorado Rockies. In the Mid-Continent, the Company is able to (i) increase its technical expertise that it has developed as one of the most active drillers and operators in the region and leverage that expertise in the interpretation of geological and operational opportunities, (ii) achieve economies of scale and breadth of operations, both of which help to control costs, (iii) take advantage of investments in infrastructure including electrical delivery and saltwater gathering and disposal systems and (iv) opportunistically grow its holdings through acquisitions, farmouts and operations in this area to achieve production and reserve growth. With the recent acquisition of Rockies acreage and assets in Colorado's North Park Basin, the Company intends to develop a proven oil resource play similar to that being developed in Colorado's DJ Basin, both areas drawing from the oil rich Niobrara Shale. In the Rockies, the Company intends to apply its core competencies in developing medium depth formations and deploy its expertise in multi-stage fracture stimulation, artificial lift and extended and multi-lateral wellbore designs. Additionally, as operator of a majority of its wells, the Company has flexibility to utilize these competitive advantages to deliver strong, sustainable returns.

Preservation of Capital in Depressed Commodity Pricing Environment. Volatility of pricing can significantly impact the amount of revenue received for oil and natural gas production and the level of economic returns the Company receives for amounts invested in its exploration and development activities. Over time, costs to drill, complete and operate wells typically adjust to prevailing commodity price levels, resulting in improved and more certain returns; however, during periods of depressed oil and natural gas pricing, such as that which began during the second half of 2014 and is continuing, the Company preserves capital and liquidity by contracting its capital expenditures budget and high-grading locations for development. During such times, the Company capitalizes on in place infrastructure, such as the Company's saltwater gathering and disposal and electrical systems, by focusing drilling efforts on locations that can most effectively make use of this existing infrastructure. Additionally, exploration programs are conducted within a high-graded inventory of locations that have a greater certainty of economic returns. The Company's 2016 capital expenditures budget is approximately $285.0 million, with approximately $262.0 million designated for exploration and production activities.

Focus on Cost Efficiency and Capital Allocation. By leveraging its experienced workforce, scalable operational structure and infrastructure systems, the Company is able to achieve cost efficiencies and sustainable returns in the Mid-Continent and Niobrara Shale in the Rockies. In the Mid-Continent, with a focus on lower-risk, high rate of return and repeatable drilling opportunities with long economic lives, the Company has made improvements in its multi-lateral wellbore designs, its completion designs, well site production facilities, utilization of pad drilling, its vendor contracts and spud-to-spud cycle time to further reduce its cost structure in the Mid-Continent. Further, due to the low pressure and shallow characteristics of the reservoirs the Company develops, the Company is able to maintain a low-cost operating structure and manage service costs. Similar opportunities exist in the development of the Niobrara Shale in the Rockies, where technologies developed in the Mid-Continent are transferable. The ability to drill multiple laterals from a single pad or single vertical wellbore is expected to facilitate cost-effective development of this oil rich resource play.

Mitigate Commodity Price Risk. As appropriate, the Company enters into derivative contracts to mitigate a portion of the commodity price volatility inherent in the oil and natural gas industry. By increasing the predictability of cash inflows for a portion of its future production, the Company is better able to mitigate funding risks for its longer term development plans and lock-in rates of return on its capital projects.

Develop Key Infrastructure Systems. By constructing a saltwater gathering and disposal system and electrical delivery system to service its Mid-Continent properties, the Company is able to produce oil and natural gas more efficiently and, therefore, more economically, giving it a competitive advantage over other operators in this rural area. Expertise developed by the Company in planning and executing large scale infrastructure and midstream projects in the Mid-Continent is being directly applied to the development of the Niobrara Shale.

Maintain Flexibility. The Company has multi-year inventories of both oil and natural gas drilling locations within its core operating area. Maintaining inventories of both oil and natural gas drilling locations allows the Company to efficiently direct capital toward projects with the most attractive returns.

Pursue Opportunistic Acquisitions. The Company periodically reviews acquisition targets to complement its existing asset base. The Company selectively identifies such targets based on several factors including relative value, hydrocarbon mix and location, and the relative fit of the Company's core competencies and technical expertise and, when appropriate, seeks to acquire them at a discount to other opportunities.

Acquisitions and Divestitures

2016 Divestiture and Release from Treating Agreement

On January 21, 2016, the Company transferred ownership of substantially all of its oil and natural gas properties and midstream assets located in the Piñon field in the West Texas Overthrust ("WTO") and $11.0 million in cash to a wholly owned subsidiary of Occidental Petroleum Corporation ("Occidental") and was released from all past, current and future claims and obligations under an existing 30-year treating agreement between the companies. For the year ended December 31, 2015, production, revenues and direct operating expenses for the conveyed oil and natural gas properties were 1.9 MMBoe, $14.6 million and $41.1 million, respectively. Additionally, during the year ended December 31, 2015, the Company accrued approximately $34.9 million in penalties related to the Company's shortfall in meeting its 2015 annual CO_2 delivery requirement under the 30-year treating agreement that was terminated in accordance with the terms of the transaction.

The assets of Piñon Gathering Company, LLC ("PGC"), which were acquired by the Company in October 2015 as discussed further below, were included in the consideration conveyed to Occidental.

2015 Acquisitions

Piñon Gathering Company, LLC. In October 2015, the Company acquired the assets of and terminated a gas gathering agreement with PGC for $48.0 million in cash and $78.0 million principal amount of newly issued 8.75% Senior

Secured Notes due 2020 (“Senior Secured Notes”). PGC owns approximately 370 miles of gathering lines supporting the natural gas production from the Company's Piñon field in the WTO.

Rockies Properties - North Park Basin. In December 2015, the Company acquired approximately 135,000 net acres in the North Park Basin, Jackson County, Colorado for approximately $191.1 million in cash, including post-closing adjustments. Also included in the acquisition were working interests in 16 wells previously drilled on the acreage. Additionally, the seller paid the Company $3.1 million for certain overriding interests retained in the properties.

2014 Divestiture

Sale of Gulf of Mexico and Gulf Coast Properties. On February 25, 2014, the Company sold certain of its subsidiaries that owned the Company's Gulf of Mexico and Gulf Coast oil and natural gas properties (collectively, the "Gulf Properties"), to Fieldwood Energy, LLC ("Fieldwood") for $702.6 million, net of working capital adjustments and post-closing adjustments, and Fieldwood's assumption of approximately $366.0 million of related asset retirement obligations. The Company used the proceeds from the sale to fund its drilling in the Mid-Continent. Additionally, the Company settled a portion of its existing oil derivative contracts in January and February 2014 prior to their respective maturities to reduce volumes hedged in proportion to the anticipated reduction in daily production volumes due to the sale, which resulted in the Company making cash payments of approximately $69.6 million. The Company retained a 2% overriding royalty interest in certain exploration prospects.

In accordance with the terms of the sale, the Company agreed to guarantee on behalf of the buyer certain plugging and abandonment obligations associated with the Gulf Properties for a period of up to one year from the date of closing. Additionally, the buyer agreed to indemnify the Company for any costs it may incur as a result of the guarantee. The Company did not incur any costs as a result of this guarantee, and was released from the obligation during the third quarter of 2015.

2013 Divestiture

Sale of Permian Properties. On February 26, 2013, the Company sold its oil and natural gas properties in the Permian Basin area of west Texas, excluding the assets associated with the SandRidge Permian Trust area of mutual interest (the "Permian Properties") for net proceeds of $2.6 billion, including post-closing adjustments that were finalized in the third quarter of 2013. The Company used a portion of the sale proceeds to fund the redemption of approximately $1.1 billion aggregate principal amount of outstanding senior notes and used the remaining proceeds to fund capital expenditures in the Mid-Continent and for general corporate purposes. Including final post-closing adjustments, the Company recorded a non-cash loss on the sale of $398.9 million, of which $71.7 million was allocated to noncontrolling interests. Additionally, the Company settled a portion of its existing oil derivative contracts in February 2013 prior to their contractual maturities to reduce volumes hedged in proportion to the anticipated reduction in daily production volumes due to the sale, which resulted in a loss on settlement of approximately $29.6 million.

PRIMARY BUSINESS OPERATIONS

The Company's dominant segment is its exploration and production business, which explores for, develops and produces oil and natural gas. Financial information for this segment and the Company's two other reportable business segments, the drilling and oilfield services and midstream services segments, is provided in Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Note 23—Business Segment Information" to the Company's consolidated financial statements in Item 8 of this report. The information below includes the interests and activities of SandRidge Mississippian Trust I (the "Mississippian Trust I"), SandRidge Permian Trust (the "Permian Trust") and SandRidge Mississippian Trust II (the "Mississippian Trust II") (collectively, the "Royalty Trusts"), including amounts attributable to noncontrolling interest, all of which are included in the exploration and production segment.

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The following table presents information concerning the Company's exploration and production activities by geographic area of operation as of December 31, 2015, unless otherwise noted.

Area	Estimated Net Proved Reserves (MMBoe)	PV-10 (In millions)(1)	Daily Production (MBoe/d)(2)	Reserves/ Production (Years)(3)	Gross Acreage	Net Acreage	Capital Expenditures (In millions) (4)
Mid-Continent	259.1	$ 1,171.8	59.5	11.9	1,826,050	1,273,232	$ 655.4
Rockies	27.6	18.4	0.5	—	148,509	134,933	—
West Texas	37.9	124.8	8.3	12.5	88,244	68,210	4.9
Total	324.6	$ 1,315.0	68.3	13.0	2,062,803	1,476,375	$ 660.3

(1) For a reconciliation of PV-10 to Standardized Measure, see "—Proved Reserves." The Company's total Standardized Measure was $1.3 billion at December 31, 2015.
(2) Average daily net production for the month of December 2015.
(3) Estimated net proved reserves as of December 31, 2015 divided by production for the month of December 2015 annualized.
(4) Capital expenditures for the year ended December 31, 2015 on an accrual basis.

Properties

Mid-Continent

The Company held interests in approximately 1,826,000 gross (1,273,000 net) leasehold acres primarily in Oklahoma and Kansas at December 31, 2015. Associated proved reserves at December 31, 2015 totaled 259.1 MMBoe, 85% of which were proved developed reserves, based on estimates prepared by Cawley, Gillespie & Associates, Inc., ("CG&A") and the Company's internal engineers. The Company's interests in the Mid-Continent as of December 31, 2015 included 2,386 gross (1,392.2 net) producing wells with an average working interest of 59%. The Company had four rigs operating in the Mid-Continent as of December 31, 2015, all of which were drilling horizontal wells. The Company drilled a total of 165 wells in this area during 2015, of which 161 were horizontal wells and four were saltwater disposal wells.

Mississippian Formation. A key target for exploration and development within the Mid-Continent area is the Mississippian formation, which is an expansive carbonate hydrocarbon system located on the Anadarko Shelf in northern Oklahoma and southern Kansas. The top of this formation is encountered between approximately 4,000 and 7,000 feet and lies stratigraphically between various formations of Pennsylvanian age and the Devonian-aged Woodford Shale formation. The Mississippian formation can reach 1,000 feet in gross thickness and have targeted porosity zone(s) ranging between 20 and 150 feet in thickness. At December 31, 2015, the Company had approximately 1,732,000 gross (1,218,000 net) acres under lease in the Mississippian formation.

The Company has drilled approximately 1,675 wells in this formation as of December 31, 2015. From December 31, 2014 to December 31, 2015, the number of the Company's producing horizontal wells in the Mississippian formation increased from 1,555 to 1,726. Of the wells the Company drilled in the Mississippian formation during 2015, three wells are subject to the royalty interests of the Mississippian Trust II. The Company fulfilled its drilling obligation to the Mississippian Trust II in March 2015.

Other Formations. The Company drilled 23 wells in the Chester formation and eight wells in the Woodford formation in 2015 in order to determine commerciality and initiate development of these productive formations.

Historically drilled with vertical wells, the Chester formation in the Northern Mid-Continent is currently being targeted for horizontal development. The formation, which lies beneath various Pennsylvanian-aged formations and above the Mississippian formation, is composed of stacked low permeability sandstone and carbonate layers interbedded with shale. The top of the formation occurs at about 5,600 feet and ranges in thickness from less than 100 to over 1,000 feet. Individual target zones within the formation range from 15 to 50 feet in thickness.

Long regarded as the primary source rock for most Mid-Continent reservoirs, the Woodford formation is now itself being developed horizontally across much of Oklahoma. This Devonian-aged formation, which lies beneath the Mississippian formation and above various Lower Paleozoic formations, is stratigraphically equivalent to the Marcellus Shale in the

Appalachian Basin and the Bakken Shale in the Williston Basin. It is composed of alternating layers of organic-rich shale and less organic-rich siliceous or carbonate-rich shale. The top of the formation in the exploration and development area ranges from 6,200 to 10,000 feet, and the thickness of the formation ranges from less than 50 to over 100 feet.

Gathering and Disposal and Electrical Systems. The Company's electrical infrastructure, owned by the Company's midstream services segment, and saltwater gathering and disposal system assist in the economically efficient production of oil and natural gas in the Mid-Continent. The Company's electrical infrastructure, which consisted of approximately 1,122 miles of power lines and seven substations at December 31, 2015, coordinates the delivery of electricity to the Company's Mid-Continent operations at a lower cost than electricity provided by on-site generation. Additionally, by building its own infrastructure in these rural areas, the Company has been able to provide sufficient electricity to its operations. The Company is also able to obtain lower electrical rates based on aggregated volumes. The saltwater gathering and disposal system, which included more than 150 active wells and approximately 1,150 miles of gathering lines at December 31, 2015, reduces the overall cost of water disposal, which directly reduces production costs. The system has a current injection capacity of over 2.0 million barrels of water per day.

Rockies

The Company acquired its Rockies assets, located in the North Park Basin in Jackson County, Colorado, in December 2015. At December 31, 2015, the properties consisted of approximately 149,000 gross (135,000 net) acres and operated working interests in 16 previously drilled producing wells with an average working interest of 100%. Associated proved reserves at December 31, 2015 were approximately 27.6 MMBoe, of which approximately 6% were proved developed reserves. The Rockies acreage is located within the Niobrara Shale play. The Niobrara Shale is characterized by numerous stacked pay reservoirs at depths of 5,500 to 9,000 feet with reservoir thickness over 450 feet.

West Texas

The Company's west Texas oil and natural gas properties include properties in the WTO and the Permian Basin. As of December 31, 2015, the Company's west Texas properties consisted of approximately 88,000 gross (68,000 net) leasehold acres, 2,009 gross (1,963.5 net) producing wells with an average working interest of 98%. Associated proved reserves at December 31, 2015 were 37.9 MMBoe, 100% of which were proved developed reserves. The Company did not drill any wells in this area during 2015.

As discussed in "2016 Divestiture and Release from Treating Agreement" above, the Company divested its WTO oil and natural gas properties in January 2016. Also, under the terms of the transaction, the Company was released from its past, current and future obligations under a 30-year treating agreement pursuant to which (i) the Company delivered natural gas produced in the WTO to Occidental's CO_2 treatment plant in Pecos County, Texas (the "Century Plant") and (ii) Occidental removed CO_2 from natural gas volumes delivered by the Company. The Company retained all methane gas after treatment. Under the agreement, the Company was required to deliver a total of approximately 3,200 Bcf of CO_2 during the agreement period. The Company was obligated to pay Occidental $0.25 per Mcf to the extent minimum annual CO_2 volume requirements were not met and $0.70 per Mcf to the extent the total contract delivery requirement was not met by the end of the contract term.

Proved Reserves

Preparation of Reserves Estimates

The estimates of oil, natural gas and NGL reserves in this report are based on reserve reports, the substantial majority of which were prepared by independent petroleum engineers. To achieve reasonable certainty, the Company's engineers relied on technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used to estimate the Company's proved reserves include, but are not limited to, well logs, geological maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. This data was reviewed by various levels of management for accuracy, before consultation with independent petroleum engineers. Such consultation included review of properties, assumptions and any new data available. The Corporate Reservoir department's internal reserves estimates and methodologies were compared to those prepared by independent petroleum engineers to test the reserves estimates and conclusions before the reserves estimates were included in this report. The accuracy of the reserve estimates is dependent on many factors, including the following:

- the quality and quantity of available data and the engineering and geological interpretation of that data;

- estimates regarding the amount and timing of future costs, which could vary considerably from actual costs;

- the accuracy of economic assumptions such as the future price of oil and natural gas; and

- the judgment of the personnel preparing the estimates.

SandRidge’s Senior Vice President—Corporate Reservoir Engineering is the technical professional primarily responsible for overseeing the preparation of the Company’s reserves estimates. He has a Bachelor of Science degree in Petroleum Engineering with over 30 years of practical industry experience, including over 30 years of estimating and evaluating reserve information. He has also been a certified professional engineer in the state of Oklahoma since 2007 and a member of the Society of Petroleum Engineers since 1980.

SandRidge’s Reservoir Engineering Department continually monitors asset performance, making reserves estimate adjustments, as necessary, to ensure the most current reservoir information is reflected in reserves estimates. Reserve information includes production histories as well as other geologic, economic, ownership and engineering data. The Corporate Reservoir department currently has a total of 20 full-time employees, comprised of 11 degreed engineers and nine engineering and business analysts with a minimum of a four-year degree in mathematics, finance or other business or science field.

The Company maintains a continuous education program for its engineers and analysts on new technologies and industry advancements and also offers refresher training on basic skill sets.

In order to ensure the reliability of reserves estimates, internal controls within the reserve estimation process include:

- no employee’s compensation is tied to the amount of reserves recorded.
- reserves estimates are prepared by experienced reservoir engineers or under their direct supervision.
- the Senior Vice President—Corporate Reservoir Engineering reports directly to the Company’s Chief Operating Officer.
- the Reservoir Engineering Department follows comprehensive SEC-compliant internal policies to determine and report proved reserves including:
- confirming that reserves estimates include all properties owned and are based upon proper working and net revenue interests;
- reviewing and using in the estimation process data provided by other departments within the Company such as Accounting; and
- comparing and reconciling the Corporate Reservoir department’s internally generated reserves estimates to those prepared by third parties.

Each quarter, the Senior Vice President—Corporate Reservoir Engineering presents the status of the Company’s reserves to a committee of executives, which subsequently approves all changes.

The Reservoir Engineering Department works closely with its independent petroleum consultants at each fiscal year end to ensure the integrity, accuracy and timeliness of annual independent reserves estimates. These independently developed reserves estimates are reviewed by the Audit Committee, as well as the Chief Financial Officer, Senior Vice President of Accounting, Director of Internal Audit, Vice President of Financial Reporting and General Counsel and are approved as the Company’s corporate reserves. In addition to reviewing the independently developed reserve reports, the Audit Committee annually meets with the principal engineers who are primarily responsible for the reserve reports. The Audit Committee also periodically meets with the other independent petroleum consultants that prepare estimates of proved reserves.

The percentage of the Company’s total proved reserves prepared by each of the independent petroleum consultants is shown in the table below.

	December 31,					
	2015		2014		2013	
Cawley, Gillespie & Associates, Inc.	77.7	%	82.4	%	64.6	%
Ryder Scott Company, L.P.	8.5	%	—	%	—	%
Netherland, Sewell & Associates, Inc.	3.9	%	3.7	%	21.5	%
Total	90.1	%	86.1	%	86.1	%

The remaining 9.9%, 13.9% and 13.9% of the Company’s estimated proved reserves as of December 31, 2015, 2014 and 2013, respectively, were based on internally prepared estimates.

Copies of the reports issued by the Company’s independent petroleum consultants with respect to the Company’s oil, natural gas and NGL reserves for the substantial majority of all geographic locations as of December 31, 2015 are filed with this report as Exhibits 99.1, 99.2 and 99.3. The geographic location of the Company’s estimated proved reserves prepared by each of the independent petroleum consultants as of December 31, 2015 is presented below.

	Geographic Locations—by Area by State
Cawley, Gillespie & Associates, Inc.	Mid-Continent—KS, OK
Ryder Scott Company, L.P.	Rockies—CO
Netherland, Sewell & Associates, Inc.	Permian Basin—TX

The qualifications of the technical personnel at each of these firms primarily responsible for overseeing the firm’s preparation of the Company’s reserves estimates included in this report are set forth below. These qualifications meet or exceed the Society of Petroleum Engineers’ standard requirements to be a professionally qualified Reserve Estimator and Auditor.

Cawley, Gillespie & Associates, Inc.

- more than 28 years of practical experience in petroleum engineering and more than 26 years of experience estimating and evaluating reserve information;
- a registered professional engineer in the state of Texas; and
- Bachelor of Science Degree in Petroleum Engineering.

Ryder Scott Company, L.P.

- more than 30 years of practical experience in the estimation and evaluation of petroleum reserves;
- a registered professional engineer in the states of Alaska, Colorado, Texas and Wyoming; and
- Bachelor of Science Degree in Petroleum Engineering and MBA in Finance;

Netherland, Sewell & Associates, Inc.

- practicing consulting petroleum engineering since 2013 and over 15 years of prior industry experience;
- licensed professional engineers in the state of Texas; and
- Bachelor of Science Degree in Chemical Engineering

Technologies

Under SEC rules, proved reserves are those quantities of oil, natural gas and NGLs, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, based on prices used to estimate reserves, 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. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil, natural gas and/or NGLs actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

The area of a reservoir considered proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil, natural gas or NGLs on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. In determining the amount of proved reserves, the price used must be the average price during the 12-month period prior to the ending date of the period covered by the reserve report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

The estimates of proved developed reserves included in the reserve report were prepared using decline curve analysis to determine the reserves of individual producing wells. After estimating the reserves of each proved developed well, it was determined that a reasonable level of certainty exists with respect to the reserves that can be expected from close offset undeveloped wells in the field.

Development Plan

Based on the economic conditions on December 31, 2015, the Company approved of a plan to develop the proved undeveloped locations identified in the Company’s reserve report within five years of initial booking, in accordance with SEC regulations. The reserve report anticipated a three rig drilling program for the first half of 2016 and four rigs in the second half of the year. Two rigs were scheduled to drill primarily proved undeveloped locations in the first half of 2016, increasing to three rigs in the second half of the year.

However, persistently low commodity prices through the first quarter of 2016 have negatively impacted the Company’s results of operations, financial condition and future development plans. As a result, the Company intends to scale back to a two rig drilling program beginning in the second quarter of 2016. If commodity pricing falls short of the Company's current expectations or rebounds to a level supportive of more drilling, the Company may change its 2016 capital expenditure plans again. However, the Company's management does not expect these short term changes to negatively impact the Company's ability to develop all of its December 31, 2015 proved undeveloped locations within the five year time frame described above, nor does it expect such changes to have a significant impact to the Company's overall development plan or PV-10 as presented in the Company's December 31, 2015 reserve report.

Reporting of Natural Gas Liquids

NGLs are produced as a result of the processing of a portion of the Company's natural gas production stream. At December 31, 2015, NGLs comprised approximately 19% of the Company's total proved reserves on a barrel equivalent basis and represented volumes to be produced from properties where the Company has contracts in place for the extraction and separate sale of NGLs. NGLs are products sold by the gallon. In reporting proved reserves and production of NGLs, the Company has included production and reserves in barrels. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. All production information related to natural gas is reported net of the effect of any reduction in natural gas volumes resulting from the processing and extraction of NGLs.

Reserve Quantities, PV-10 and Standardized Measure

The following estimates of proved oil, natural gas and NGL reserves are based on reserve reports as of December 31, 2015, 2014 and 2013, the substantial majority of which were prepared by independent petroleum engineers. The estimates include reserves attributable to the Royalty Trusts, including amounts associated with noncontrolling interest. The PV-10 values shown in the table below are not intended to represent the current market value of the Company's estimated proved reserves as of the dates shown. The reserve reports were based on the Company's drilling schedule and the average price during the 12-month periods ended December 31, 2015, 2014 and 2013, using first-day-of-the-month prices for each month. Such prices are not reflective of actual prices at December 31, 2015 or current prices. See further discussion of prices in "Risk Factors" included in Item 1A of this report. At December 31, 2015, the Company estimated that approximately 100% of its current proved undeveloped reserves will be developed by the end of 2020. See "Critical Accounting Policies and Estimates" in Item 7 of this report for further discussion of uncertainties inherent to the reserves estimates.

	December 31,		
	2015	2014	2013
Estimated Proved Reserves(1)			
Developed			
Oil (MMBbls)	48.6	79.0	83.9
NGL (MMBbls)	51.1	56.8	35.8
Natural gas (Bcf)	964.6	1,203.4	951.6
Total proved developed (MMBoe)	260.5	336.4	278.3
Undeveloped			
Oil (MMBbls)	29.3	47.0	58.7
NGL (MMBbls)	9.9	35.0	23.3
Natural gas (Bcf)	149.2	584.8	438.8
Total proved undeveloped (MMBoe)	64.1	179.5	155.1
Total Proved			
Oil (MMBbls)	77.9	126.0	142.6
NGL (MMBbls)	61.0	91.8	59.1
Natural gas (Bcf)	1,113.8	1,788.2	1,390.4
Total proved (MMBoe)(2)	324.6	515.9	433.4
PV-10 (in millions)(3)	$1,315.0	$5,516.4	$5,191.6
Standardized Measure of Discounted Net Cash Flows (in millions)(2)(4)	$1,314.6	$4,087.8	$4,017.6

(1) The Company's estimated proved reserves and the future net revenues, PV-10 and Standardized Measure were determined using prices calculated as a 12-month unweighted average of the first-day-of-the-month index price for each month of each year. All prices are held constant throughout the lives of the properties. The index prices and the equivalent weighted average wellhead prices used in the Company's reserve reports are shown in the table below.

	Index prices (a)		Weighted average wellhead prices (b)		
	Oil (per Bbl)	Natural gas (per Mcf)	Oil (per Bbl)(c)	NGL (per Bbl)	Natural gas (per Mcf)
December 31, 2015	$46.79	$2.59	$45.29	$12.68	$1.87
December 31, 2014	$91.48	$4.35	$91.65	$32.79	$3.61
December 31, 2013	$93.42	$3.67	$95.67	$31.40	$3.65

(a) Index prices are based on average West Texas Intermediate posted prices for oil and average Henry Hub spot market prices for natural gas.

(b) Average adjusted volume-weighted wellhead product prices reflect adjustments for transportation, quality, gravity, and regional price differentials.

(c) At December 31, 2013, the weighted average wellhead oil price is significantly higher than the index price as a result of favorable location differentials for production in the Gulf of Mexico.

(2) Estimated total proved reserves and Standardized Measure include amounts attributable to noncontrolling interests, as shown in the following table:

	Estimated Proved Reserves (MMBoe)	Standardized Measure (In millions)
December 31, 2015	19.1	$224.6
December 31, 2014	27.6	$643.3
December 31, 2013	29.9	$781.6